Office of the Secretary
Service Date
August 11, 1999

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF THE WASHINGTON WATER POWER COMPANY (NOW AVISTA CORPORATION DBA AVISTA UTILITIES—WASHINGTON WATER POWER DIVISION) FOR AN ORDER APPROVING INCREASED RATES AND CHARGES FOR ELECTRIC SERVICE IN THE STATE OF IDAHO.	)	**CASE NO. WWP-E-98-11** **ERRATA NOTICE TO ORDER NO. 28097**

On July 29, 1999, the Idaho Public Utilities Commission issued Order No. 28097, in the above referenced case. The following correction should be made to Appendix D of that Order.

Extra Large General Service - Schedule 25, Commission Ordered Rates

Where it reads:

Annual Minimum <u>$419,230.00</u>

Should read:

Annual Minimum <u>$397,670.00</u>

DATED at Boise, Idaho this 11th day of August 1999 .

Myrna J. Walters
Myrna J. Walters
Commission Secretary

O:wwpe9811_err

Office of the Secretary
Service Date
July 29, 1999

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF THE WASHINGTON WATER POWER COMPANY (NOW AVISTA CORPORATION DBA AVISTA UTILITIES—WASHINGTON WATER POWER DIVISION) FOR AN ORDER APPROVING INCREASED RATES AND CHARGES FOR ELECTRIC SERVICE IN THE STATE OF IDAHO.	**CASE NO. WWP-E-98-11** **ORDER NO. 28097**

On December 18, 1998, the Idaho Public Utilities Commission (Commission) received an Application from The Washington Water Power Company, now Avista Corporation dba Avista Utilities — Washington Water Power Division (Avista; Company; WWP) requesting authority to increase its rates and charges for electric service in the state of Idaho. The Company's original request of $14,223,000 or 11.56% was revised at hearing to $13,456,000 or 10.94%. By this Order the Commission authorizes the Company to increase its revenues by $9,330,000, or approximately 7.58%. We approve a pro forma rate base of $360,546,000, a return on equity of 10.75% and an overall rate of return of 8.979%.

APPLICATION

Avista is a public utility engaged in the generation, transmission and distribution of electric power and the distribution of natural gas. Avista serves approximately 100,000 customers in northern Idaho ranging from Grangeville to Sandpoint. The Company in its Application requested a Commission Order approving revised rates and charges effective January 22, 1999. The proposed effective date was suspended pending hearing on the Application and further order of the Commission. (Commission Order Nos. 27852 and 28098; Reference *Idaho Code* § 61-622.)

The Company's last general rate case in Idaho was in 1986 (ref. Case No. U-1008-256, Order No. 20905). Since that time, Avista's overall electric rates in Idaho have been modified with the implementation in March 1995 of a non-bypassable 1.5% energy surcharge to fund energy efficiency improvements and a Power Cost Adjustment (PCA) mechanism implemented in 1989. The PCA has resulted in several temporary rate adjustments, both surcharges and rebates, to reflect changes in power costs related to stream flow and wholesale market conditions.

Avista amended its original request at hearing to an overall increase in annual revenue for its Idaho electric jurisdiction of $13,456,000, or 10.94%. Reference Exh. 24, Sch. 1, p. 1; Tr. p. 678. Avista proposes to set rates for individual customer classes based in part on a cost of service study. Therefore, the amount of the Company proposed percentage increases varies by class of customer and by usage.

The Company's proposed rate increase will also apply to those customers formerly served by PacifiCorp (Clark Fork, Hope, East Hope, Old Town, Priest River and Sandpoint). The four-year rate transition period applicable to those customers expired in January 1999 when they were transferred to the Company's comparable rate schedules. Reference Case No. WWP-E-94-1.

The Company's requested revenue increase is predicated on a 9.446% rate of return, including an 11.75% return on equity and a proposed 25 basis point equity adder as a bonus incentive. The Company states that for its proposed test year, 1997, its rate of return in Idaho, on a pro forma basis, was 7.075%, significantly below its authorized rate of return of 10.95%. Exh. 24, p.7. Avista alleges that the rates in its present tariff are no longer reasonable or adequate and do not allow it to earn a fair and reasonable return on investment.

HEARING

The technical hearing on this Application was held in Sandpoint, Idaho, on June 8-9, 1999. The following parties appeared by and through their respective counsel:

Avista Corporation dba Avista Utilities— Washington Water Power Division	David J. Meyer, Esq.
Potlatch Corporation	Conley Ward, Esq.
Hecla Mining Company Silver Valley Resources Corp Sunshine Mining & Refining Company	M. Karl Shurtliff, Esq.
Commission Staff	Scott Woodbury, Esq.

Also held on June 8 was an evening hearing for the purpose of receiving public comment and testimony on the Company's Application. Two members of the public appeared and commented. The remarks of Shawn Keough, State Senator for Legislative District 1 are discussed starting at page 28 of this Order. Tr. pp. 549-565.

Motion to Dismiss

After some initial questions of Avista's Board Chairman and Chief Executive Officer regarding Centralia, Potlatch made a Motion to Dismiss the Company's Application without prejudice to refiling at such later time when uncertainty regarding the potential sale of Centralia has been settled. Tr. p. 51; Reference IDAPA 31.01.01.056; -256.

Potlatch contends based on an item reported in recent industry publications that Avista has entered into an agreement to sell its 15% interest in the Centralia coal-fired generating station. Tr. p. 49. Centralia represents approximately 200 megawatts of Avista's thermal generating capacity. Reference Exh. 3. The proposed sale is subject to regulatory approval, a process that the Company anticipates may take 12 to 18 months.

In this rate case Avista uses a 1997 test year. As part of its adjustments to the test year, however, the Company uses a projected July 1999 – June 2000 time period for pro forma power supply expense. Tr. p. 50. Centralia is included in the Company's power supply or dispatch simulation model. The dispatch model is used to normalize for ratemaking purposes power costs that are dependent upon stream flow and wholesale market conditions. Tr. p. 379.

Potlatch argues that if the sale of Avista's interest in Centralia is approved, the result will be a reduction in the Company's rate base, a related power supply expense adjustment and a distribution back to ratepayers of depreciation. Tr. p. 52. Idaho's allocated revenue deficiency in this case as filed by the Company is roughly $9 million before it is grossed up for taxes. Potlatch concludes that any combination of reduction in power supply, reduction in rate base or rebates or credits to customers for depreciation previously paid that total $9 million will remove or simply wipe out the Company's rate case. Tr. p. 53. The Commission, Potlatch contends, cannot simply set rates now and adjust for Centralia later. To do so, it suggests, will result in a mismatch of revenues, expenses and accounting items.

Avista opposes Potlatch's Motion to Dismiss pointing out substantial uncertainties surrounding the sale as to timing, regulatory approvals, and related conditions. Avista argues that the results of the sale, if it does occur, including questions regarding replacement power, are neither known nor measurable. Tr. pp. 55, 56. At hearing the Commission took Potlatch's Motion under advisement.

Findings:

We have now had the opportunity to fully consider Potlatch's Motion to Dismiss and the related arguments of the parties. Although the possible ramifications of the Centralia sale have been identified by Potlatch, it was done only on a general basis. We find that there are presently too many unknowns, and too many uncertainties regarding the proposed sale for that to be the basis of a ruling in this case. The facts presented in this case regarding the Centralia sale neither support nor justify dismissal of the Company's Application.

It is the Commission's understanding that there have as yet been no regulatory filings regarding the proposed sale. Although raised at hearing (Tr. p. 52), the Commission reserves judgment as to the applicability of *Idaho Code* § 61-328—Electric Utilities—Sale of Property to be Approved by Commission. We note that the Company's ownership interest in Centralia is part of its rate base in Idaho on which it receives a return on investment. We therefore put Avista on notice that prior to any transfer of its ownership interest in Centralia we expect a filing by Avista with this Commission addressing the proposed sale, its ramifications, rate consequences and the Company's proposed treatment of same.

Test Year

In this case Avista proposes use of a historical twelve-month test year period ending December 31, 1997, with operating adjustments to both rate base and operating results for post-test year changes. Tr. p. 571. Staff and Intervenors object to some of the adjustments but no party objects to the proposed test year.

Findings:

The Commission finds the use of a historical test year period ending December 31, 1997 to be reasonable for the purposes of this rate case.

Operating Results—Adjustments to Test Year Revenues and Expenses

Having selected a 1997 test year, Avista, and subsequently Staff and Potlatch proposed adjustments to specific booked amounts for revenues, expenses and rate base. Adjustments to test year revenues and expenses often are necessary 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. Some of the adjustments to revenues and expenses also affect rate base. As set forth in Company Rebuttal Exhibit 24, Sch. 1 p. 1 a revised annual revenue increase of $13,456,000 or 10.94% is requested.

The Company has agreed to and incorporated into its Rebuttal Exhibit 24, Sch. 1 results of operations, the Staff proposed adjustments to operating expense for depreciation, tree trimming, and income tax. Tr. pp. 133, 134. The net income after taxes agreed to by the Company is as follows:

Depreciation Adjustment	$463,048
Tree Trimming Adjustment	$322,471
Income tax Adjustment	$ 16,670

Pro Forma Revenue Adjustments — Staff and Potlatch

Commission Staff, based on its analysis, calculates a revenue deficiency of $10,234,000 and recommended an 8.32% increase. Reference Exh. No. 118, p. 3. The difference between the Company requested and Staff calculated revenue requirement is $3,222,000.

Potlatch, based on its analysis, concluded that the Company's original rate increase request was overstated by approximately $11.5 million. Tr. p. 1222

Of the Staff proposed adjustments, four remain contested by the Company: Hydro Re-licensing costs—Clark Fork Settlement Agreement; CIAC adjustment (line extension); Injuries And Damages (1996 Ice Storm); and Miscellaneous General Expense (FERC Acct 930).

Potlatch provides testimony and recommendations regarding Avista's marketing efforts—specifically: allocation of costs/benefits regarding secondary transactions. Potlatch also proposes adjustments regarding depreciation, normalized net power supply cost, hydro-relicensing, amortization of 1996 ice storm costs and rate of return.

Hydro Relicensing Costs—Clark Fork Settlement Agreement

The Company is presently attempting to relicense two of its hydro generation facilities, Cabinet Gorge and Noxon Rapids (Clark Fork projects). Unless renewed, the FERC licenses are scheduled to expire in 2001. Beginning in 1996 the Company initiated a collaborative negotiation relicensing process referred to as the Living License TM. Tr. pp. 619, 620. The negotiation group includes over 100 representatives from nearly 40 organizations, including federal and state agencies and local governments from Idaho and Montana, five American Indian Tribes, nongovernment organizations, conservation groups, property owners and the Company. Tr. p. 620. As part of a negotiated Settlement Agreement, the Company committed to begin implementation related to Protection, Mitigation And Enhancement (PM&E) in March of 1999, two years before the present licenses expires. Early implementation of these measures, the Company contends, became the Company's greatest point of leverage in negotiating an agreement among parties at what it argues is a much lower cost to the Company than certain agencies have the unilateral authority to approve. Tr. pp. 621, 622. With this Settlement Agreement, the Company estimates that on a system basis it will incur incremental hydropower relicensing operation and maintenance (O&M) expense at a levelized amount of $2,018,000. Tr. p. 623. On rebuttal the Company reduced and amended its PM&E expense projections to $1,861,820. Tr. p. 644; Exh. 25. The Company proposes in this case to pro form in the O&M expense levels contained in the Settlement Agreement. Capital expenditures associated with the settlement are not a component of the Company's filing. Tr. p. 644.

Staff witness Lobb recommends that $860,000 of the $2,018,000 hydro power relicensing expenses be excluded from the pro formed test year. $180,000 of the adjustment is a transpositional error in total PM&E; the remaining $680,000 is hydro relicensing expense that Staff contends is either a one-time expense or not presently "known or measurable." Reference Exhs. 104, 105.

The $860,000 recommended disallowance is a "system" number. As reflected in Exh. No. 118, p. 2, Col. E, the original adjustment on an Idaho jurisdictional basis translates to a reduction in production and transmission expenses of $285,376. Associated adjustments are an increase in state income tax in the amount of $4,191 and an increase in federal income tax in the amount of $98,415. The resultant increase to net operating income is $182,770.

Staff expressed concern regarding the potential mismatch between the projected O&M level of Settlement costs included in the Company's revenue requirement (and recovered in rates) and the actual amounts expended by the Company. The Company in rebuttal proposes that a balancing account be utilized to capture the differences between the O&M level of settlement costs ultimately allowed in rates and the amounts that get expended on an annual basis. The Company proposes using FERC Account 253, Other Deferred Debits, to accumulate a running balance that would represent either a regulatory asset or a regulatory liability. The Company proposes that any balance in the hydro relicensing deferred balancing account be consolidated with any balance in its Power Cost Adjustment (PCA) deferral account and that it be subject to refund or surcharge based upon the currently authorized $2.2 million PCA trigger mechanism. Tr. pp. 642, 643.

Staff at hearing indicated that while it is not opposed to the concept of a balancing account for Settlement O&M costs; it is opposed to combining the balancing account with the PCA. Tr. pp. 937, 938. The PCA has a $2.2 million trigger. Staff believes that the Company could delay or manipulate reaching the trigger by simply altering the timing of expenditures reflected in the relicensing account. Staff further notes that the PCA was intended to adjust for power supply expenses, especially expense variations that occur due to changing water conditions. Including another adjustment of unknown magnitude, Staff contends, would change the operation of the PCA and would be inappropriate. Staff recommends that separate subaccounts in FERC Account 253 be established and used to identify the specific relicensing O&M expenses that vary from the costs included in base rates. Staff proposes that the Commission approve its suggested relicensing expense in base rates with modifications for the bull trout adjustment ($125,000 total Company) for a total system adjustment of $735,000. Acceptance of the Staff's modified proposed adjustment results in a reduction of operating expenses of $235,997, an increase in state income tax of $3,466, and an increase in federal income tax of $81,386. The resultant increase in net operating income is $151,145. Staff recommends that costs be looked at every two to three years so they have a chance to balance out rather than adjusting every year. Tr. pp. 937-939.

Potlatch recommends that the Company's pro forma hydro relicensing cost adjustment be rejected. Potlatch contends that the adjustment will cause a mismatch of costs and benefits between present and future ratepayers. Potlatch suggests that what the Company is proposing is the equivalent of putting construction work in progress (CWIP) into rate base. Tr. p. 1212; Reference *Idaho Code* § 61-502A. Furthermore, FERC, Potlatch contends, may or may not relicense the Clark Fork projects. Potlatch recommends that the Company's hydro re-licensing adjustment be reduced by $1.4 million. Tr. p. 1222.

Findings:

The Commission has reviewed and considered the testimony and exhibits regarding the Company's proposal to recover O&M costs related to its obligations under the Clark Fork Settlement Agreement as well as the Company's proposed method of recovery. We have also considered the related comments of Staff and Potlatch. We commend the Company for its relicensing efforts. While Potlatch would have this Commission liken the Settlement PM&E expenditures to CWIP (Tr. p. 1212), we do not believe that the comparison is valid. This is not construction work in progress. By agreeing to early implementation, the Settlement Agreement benefits to the Company and its customers are clear and immediate.

We find the proposed use of a balancing account (FERC Account 253, Other Deferred Debits) to be an acceptable method of addressing the potential mismatch between recovery and expense. We find that to avoid questions related to timing of expenditures, the balancing account for Clark Fork Settlement Agreement O&M should be maintained and operated separately from the PCA. Interest shall accrue in this account in the same manner as it does in the Company's PCA account. We accept Staff's modified proposed adjustment as reasonable. The Company is encouraged to request recovery every two to three years, rather than annually. Should the Company, however, fail to make application, amortization of accrued balances will begin after three years.

CIAC Adjustment (line extensions)

Staff recommends that revenue of $1,178,835 be imputed as Contribution in Aid of Construction (CIAC). Staff contends that this additional amount should have been collected from new customers added to the Company's system between 1989 and 1997. Staff argues that the neglect and/or failure of the Company to keep line extension costs in its Schedule 51 tariff up to date, as ordered by the Commission in 1989 in Order No. 23071, has caused the Company's annual revenue requirement to be higher than it otherwise should be. Tr. pp. 967, 968.[1] The proposed amount of Staff's adjustment is based on the difference between the amount of CIAC actually collected between the years 1988 and 1997 and the amount of CIAC calculated by Staff that should have been collected. In its calculation Staff assumes that the Company's line extension costs for all the years between 1988 and 1997 escalated at the same rate of escalation as the Standard & Poor's (S&P) DRI Price Index for public utility structures. Exh. No. 110. Staff compares the assumed level of CIAC to the actual CIAC collected by the Company for each year from 1988 through 1997. The cumulative difference for the ten-year period is $1,178,835. The Company on rebuttal challenges Staff's adjustment as based more on assumptions than actual data. Tr. p. 867.

Staff's proposed adjustment results in a reduction in distribution plant depreciation expense of $26,435, an increase in state income tax of $388, and an increase in federal income tax of $9,116. The resultant increase in net operating income is $16,960. Related adjustments to rate base are a reduction in distribution plant in service of $1,152,075, a reduction in accumulated depreciation of $110,000, and an increase in deferred taxes of $403,000 for a net decrease in rate base of $639,075.

Staff also recommends that a new line extension case be opened once the rate case has been concluded in order to more closely examine the Company's line extension tariff (Schedule 51) to ensure that upward pressure on rates due to growth and new distribution plant additions is minimized. Tr. p. 968. The Company agrees with Staff that its line extension tariffs need to be more closely examined, that its line extension costs need to be updated and that allowances may need to be revised. The Company states that it is willing to initiate a collaborative effort with the Commission Staff within 90 days after the conclusion of this case to review the Company's line extension tariffs. Tr. p. 875.

Findings:

The Commission finds the Staff's proposed adjustment and method of calculation to be reasonable. Avista has failed since 1990 to provide the annual updates required by

[1] See Exh. 107 – Order No. 23071, p. 15 (4/18/90): "Company is to provide the Commission annually with updated worksheets and average unit costs for Schedule 51 construction and is to update its tariff as necessary to keep costs current"; Exh.108 – Company acknowledgement letter (1/25/91).

Commission Order No. 23071. It has not kept the extension costs current. It either did not have or failed to provide information relating to these costs. When a utility fails to maintain and/or provide the information necessary for the Commission to set rates that are fair, just, reasonable and non-discriminatory, then the best information available must be used to make the needed calculations. It is disingenuous for the Company to challenge this adjustment on the basis that some assumptions were used; it is the only entity that could have provided the actual information and it did not.

Furthermore, we note that in 1994 the Company was assessed a civil penalty of $75,000 for violating its Schedule 51 line extension tariffs by failing "to assess and collect line extension costs calculated in accordance with its tariffs." Reference Case No. WWP-E-94-9, Order No. 25838. Apparently nothing was learned from that experience and Company practices have not changed. The Company's disregard of its tariffs and this Commission's Orders is inexcusable. The Company is advised that a collaborative effort to review its line extension tariffs shall commence within 90 days of this Order and that compliance with the tariffs approved as part of that process is expected. Anything less than full compliance will cause the Commission to use its powers under *Idaho Code* § 61-706 and 61-707 to impose penalties.

Injuries and Damages (1996 Ice Storm)

The Company in this case proposes replacing the current accrual for Injuries and Damages with a six year rolling average of injuries and damage payments not covered by insurance. Reference Company Exh. 11, Col. O; Exh. 24, p. 7, PF 13. Included within the Company's rolling six-year average are uninsured damages related to the ice storm of 1996. Staff adjustment removes this amount. The Company agrees with the Staff calculation of the revised annual accrual for Injuries and Damages that corrects for the payment of an expense that was allocated to Idaho electric operations when it should have been directly assigned to Washington electric operations. The Company did not, however agree with Staff's removal of the 1996 ice storm expenses. The Staff adjustment corrects the allocation of the injury and damages expenses, and excludes the 1996 ice storm expenses. Staff contends that the ice storm was an out of test year event, extraordinary and non-recurring, not reflective of on-going expenses. Tr. p. 1063. As shown in Staff Exh. 118, Col. I, removal of the ice storm expense results in a reduction in Administrative and General (A&G) operating expense of $67,001, an increase in state tax of $984, and an increase in federal taxes of $23,106. The resultant increase in net operating income is $42,911.

Potlatch contends that the ice storm costs were incurred prior to the test year and that what the Company is proposing is retroactive ratemaking. Tr. p. 1214. Potlatch recommends that the Company's proposed adjustment be eliminated. Tr. p. 1222.

Findings:

The Commission finds removal of 1996 ice storm related expense from this case to be reasonable. While we make no judgment regarding the Company's risk management or uninsured expenditures, we do find that this is an extraordinary non-recurring expense that cannot be allowed. The Company's own publication "Ice Storm 96 Overview" states "the National Weather Service categorized this ice storm as the only event of its kind in 115 years of record. . .no comparable ice storm has occurred since the recording of weather statistics." Tr. p. 693. On rebuttal the Company asserts that it cannot be guaranteed that storm damages of this level will not reoccur. Tr. p. 651. The Company provides no evidence, however, to show with any degree of certainty how much those storm damage expenses will be. In this regard we find the transcript reference to our treatment of Idaho Power's Pacific Hide hazardous waste clean-up costs to be on point. Tr. p. 682-683; reference Idaho Power Order No. 25880. Avista's proposal to recover its uninsured costs of 1996 ice storm damage through rates would violate the principle that rates must be prospective and may not be used to recoup past losses. The proscription against retroactive ratemaking means that ice storm costs expended by the Company in the past are not recoverable through future rates unless they are preserved for that purpose by deferral or other regulatory action. When it became aware that the uninsured ice storm costs would be substantial, the Company had the opportunity to request rate relief or deferral of these costs for future recovery. It did neither. Accordingly, we cannot in this case authorize the requested recovery of this expense by including such expense in a six-year historical average.

Miscellaneous General Expense (FERC Account 930)

Based on a review of a sampling of Miscellaneous Account 930 entries (direct assignment and allocated), Staff proposes to disallow 20% of the account test year expense, $259,344 as not beneficial to customers and below-the-line expenses. Account 930 consists of

12 subaccounts, such as miscellaneous labor not elsewhere provided for, industry association dues, contributions for conventions and meetings of the industry, research, development & demonstration expenses not charged to other O&M expense accounts, and communication service not chargeable to other accounts. Tr. pp. 1066, 1067. Staff contends that included by the Company as Account 930 expense were below the line activities associated with lobbying, enhancing the image of Avista in the community and efforts to maximize shareholder value. Tr. p. 1068. The Company disputes Staff's across the board adjustment contending that the 20% reduction is an unsupported percentage which disallows a percentage of otherwise appropriate expense. The Company notes that "general" management costs often do not provide "a direct benefit to customers," yet still are essential to the operations of a major utility. Tr. p. 958. Staff's adjustment removes $259,344 of expense and provides a related increase in state income tax of $3,809, an increase in federal income tax of $89,437 for an overall increase in net operating income after taxes of $166,098. Tr. p. 1068.

Findings:

The Commission finds that the percentage adjustment to Miscellaneous Account 930 proposed by Staff is reasonable. This is an account that is a catch all for general expenses not otherwise chargeable to other accounts. The Company does not dispute that disallowable expenses have been included within the account but challenges only that some expenses are clearly appropriate utility expenditures. Allowance of 80% of the total recognizes that fact. The Company on rebuttal did not elect to provide a more detailed analysis of account entries or a better ratemaking treatment for this account. The percentage adjustment we approve is a percentage disallowance of total dollars and not a specific accounting transaction.

Secondary Transactions

Avista in this case proposes that commercial short-term purchases and sales (one year or less) be excluded from the 1997 pro forma results because the majority of such transactions were for speculative purposes and unrelated to operation of the Company's resources or serving retail load. The contracts for the commercial transactions that occurred during the 1997 test period have all terminated.[2] Speculative transactions include wholesale purchases of power that are made exclusively for resale to other wholesale parties. They also include wholesale sales of power that are covered later with purchases, also known as selling short. These transactions are unrelated to purchases made to serve retail load, as well as sales of surplus power from the Company's system. Because they are speculative in nature Avista maintains that the risks and benefits associated with these transactions should reside with the shareholders and be excluded from the retail ratemaking process. See Tr. pp. 410, 414, 415, 431-432.

Potlatch opposes the Company's proposed exclusion of secondary transactions. Utilities, Potlatch contends, have always bought and sold on the secondary market to balance loads and resources and to take advantage of attractive market conditions. Tr. pp. 1182, 1183. Secondary purchases have been used by utilities to supplement resources until load growth justifies construction of new generation, and to take advantage of prices below the variable operating costs of Company resources. Secondary sales have been used to minimize resource surpluses. Tr. p. 1183.

Potlatch contends that short-term sales are not inherently speculative. As important as who bears the gain or loss, Potlatch contends, is who was entitled to seize the opportunity and who facilitated the transaction. Tr. p. 1187. If a particular transaction relied either in whole or in part on the utility's resources, then the ratepayers, Potlatch contends, have a legitimate claim to at least a portion of the proceeds. Tr. p. 1187. Potlatch contends, that it is virtually impossible to tell in retrospect which secondary transactions are actually associated with retail loads and which were purely speculative. Tr. p. 1187. There exists, it states, some potential for self dealing and other mischief. Tr. p. 1189.

Potlatch contends that Avista recently has chosen to enter the secondary transaction market with a vengeance. Tr. p. 1176. Reference Exh. 202.

Operating Revenues		Operating Expenses	
1996	\$ .944 billion	1996	\$ .758 billion
1998	\$3.68 billion	1998	\$3.51 billion

[2] During the 1997 test period the Company made short-term purchases of 12,283,000 mwh (1,402 aMw), and short-term sales of 12,103,000 mwh (1,382 aMw). The Company's actual net system firm load for 1997 was 933 aMw. Tr. p. 411.

Only the tiniest fraction of this growth, Potlatch contends, was attributable to increased retail sales. Tr. p. 1176. The Company's power marketing activities, Potlatch notes, are not confined to unregulated affiliates. Tr. p. 1178. This transition, Potlatch contends, introduces a whole new set of financial and business risks for the utility. Tr. p. 1181.

The Company's solution, Potlatch states, is to substitute the power supply models predicted short-term transactions for actual figures. Tr. p. 1189. This, Potlatch contends, puts the model to a use that it was not intended. Tr. pp. 537, 1191. Reference Avista Exh. 6—actual 1997 short-term purchase $191.1 million adjusted to test year pro forma $16.3 million; actual 1997 short-term sales $192.4 million reduced to $9.7 million. The Company at hearing admits that future commercial trading activities or speculative transactions are not picked up, projected or calculated in the model, but contends that the model continues to do what it has in the past, i.e., calculating the costs associated with operating the resources to serve retail load and firm contract obligations. Tr. pp. 537, 538.

Potlatch suggests that Avista has not met its burden of proof in justifying the exclusion of short-term purchases and sales. Tr. p. 1193. A best estimate, Potlatch contends, is that approximately 10% of these transactions are due to hydro and 90% to market opportunities. Thus, a reasonable pro forma adjustment to the test year would be to include 90% of actual 1997 short-term sales and purchases. Tr. p. 1193. Ratepayers, Potlatch argues, should be compensated for partially underwriting these market transactions. Potlatch also proposes to allocate an additional portion of the corporate overhead and A&G expense as well as general plant rate base to speculative transactions. Tr. p. 1195; Exh. 203. The resultant Potlatch adjustment is a decrease in the revenue requirement of $3.9 million, on an Idaho jurisdictional basis. Potlatch recommends a formal rulemaking regarding speculative transactions at the conclusion of this case. Tr. p. 1197.

Based on its investigation, Staff recommends that the Commission accept the pro forma power supply adjustments proposed by the Company for the twelve-month period beginning July 1, 1999 and ending June 30, 2000, including the proposed exclusion of short-term purchases and sales not otherwise projected by the Company's power supply model. Reference Exh. 6; Tr. pp. 920, 925, 926. Staff recommends that Avista be directed, however, to separately account for short-term speculative and retail load serving transaction revenues and expenses as well as the operational costs of those activities. Tr. pp. 918, 928.

It is Staff's belief that the speculative trading engaged in by the Company is a discretionary activity that is risky and not always profitable. If ratepayers are allowed to share in the profits, they would also be subject to the losses if they should occur. Staff believes that the Company's retail customers should not be subject to such risks. Staff recommends that the operational expenses incurred by the Company for these activities be excluded, but states that it has been unable to identify all of the direct and overhead costs associated with the marketing functions or to determine an appropriate method of allocation. Tr. p. 927.

The Company on rebuttal recommends that Potlatch's proposal to include 90% of the secondary sales and purchases as a pro forma adjustment be rejected and addresses the incremental A&G costs associated with its short-term commercial or speculative trading. The net difference between short-term sales and purchases, the Company argues, cannot be used as a measure of profit because the net difference is derived primarily by the Company's load and resource balance. Tr. pp. 420, 421, 446-449. The Company agrees that there are some incremental A&G costs associated with these commercial transactions that should be excluded. Tr. pp. 449, 450. The Company contends that the costs associated with these commercial speculative activities, however, do not even begin to approach the costs Potlatch proposes to allocate to them. Potlatch's proposal to use energy to allocate the costs to the commercial trading activities, the Company contends, is inappropriate and is inconsistent with the very important ratemaking principle of "cost causation." Commercial secondary transactions, the Company notes, generally involve high volumes of energy and thin margins. Tr. p. 451.

The Company was able to estimate and identify approximately $157,200 in A&G costs associated with short-term commercial or speculative trading for the Idaho jurisdiction including such items as payroll, square footage, floor rental, janitorial service, building maintenance, etc. Reference Exh. 23, p. 12; Tr. pp. 421, 455. The Company estimates that approximately four net positions could possibly be eliminated if the short-term trading activity of the Company did not exist. Tr. p. 452. Contending that the regulated company benefits from this commercial trading activity, the Company makes no adjustment to allocate costs to commercial trading activities. Tr. pp. 414, 455, 457.

Findings:

The Commission has reviewed and considered the testimony and exhibits regarding the Company's increased trading activity and involvement in short-term commercial purchases and sales. Avista has not adequately shown that it has procedures in place and that they were adequately followed to assure this Commission that the ratepayers have not paid any of the costs associated with non-system sales. These costs must be allocated on a fully allocated basis, not an incremental basis. We are not inclined to accept Potlatch's recommendation to include the full amount or a percentage of short-term purchases and sales.

Recognizing that the Resource Optimization department of the Company does engage in some level of speculative transactions not otherwise associated with the operation of Company resources or serving retail load, we find it appropriate to make an A&G related adjustment. The Commission believes that if costs were fully allocated they would be considerably more than the incremental amounts indicated by the Company. Exhibit 210 shows actual loaded labor and other expenses for Resource Optimization for the years 1997 and 1998. These numbers include labor, taxes and benefits. The growth rate for Resource Optimization from 1997 ($8,319,969) to 1998 ($9,244,246) is calculated to be 11.1%. The Company notes that there were eight gas personnel along with thirty electric personnel in Resource Optimization. Tr. p. 514. The portion of total estimated costs allocated to electric is 30/38 or 79% of the 1997 total, i.e., $6,572,775. The calculated per person electric cost is $219,093, 79% of the total divided by 30. Only four of these personnel are identified as needed for speculative trading activities. We find the speculative trading activity costs to be four times the per person cost or $876,370 on a total system basis. The system cost adjusted to Idaho is $283,944, the retail trading cost times the 32.4% jurisdictional allocation factor. Accordingly, the Commission finds an appropriate expense adjustment for commercial secondary transactions to be $283,944. We direct Avista to develop more complete procedures to fully allocate costs to these transactions and to provide these procedures to the Commission's Staff for review.

Depreciation

Based on a Depreciation Study performed for the Company by Deloitte and Touche, Avista proposes to change depreciation rates as follows:

Functional Electric Group	Depreciation Rates Existing %	Proposed %
Steam production plant	3.12	3.38
Hydraulic production plant	1.04	1.58
Other production plant	4.18	2.36
Transmission plant	2.41	2.88
Distribution plant	2.27	2.45
General plant	6.00	12.24

Tr. p. 611.

The Company proposes a $2.4 million increase in Idaho jurisdiction depreciation. The effect of the Company's proposed adjustment decreases Idaho net operating income by $1,573,000 and reduces Idaho rate base by $807,000. Tr. pp. 617, 1034.

Staff recommends the following adjustments to the Company's depreciation request:

1.	Error in applying the rate of depreciation	$182,000
2.	Transmission net salvage adjustment	$258,000
3.	Distribution net salvage adjustment	$283,000
	Total	$723,000

Staff also recommends related adjustments to accumulated depreciation totaling $383,000 and to deferred income tax totaling $268,000. Tr. p. 1035. The level of depreciation expense recommended by Staff is set out in its Exhibit 115. The Company has requested an increase in overall composite depreciation rates from 2.46% to 2.98%. Staff's recommended increase in overall composite depreciation rates is from 2.46% to 2.85%. Tr. p. 1037.

Potlatch opposes increasing Avista plant depreciation rates. Tr. p. 1199. The depreciation rates of electric utilities, Potlatch contends, are too high as evidenced by the fact that virtually all sales of utility assets in preparation for open markets are being made at significant multiples of the regulated book value. Reference Exh. 205. Potlatch compares the depreciation rates of Avista with other utilities and believes that with the exception of distribution plant they are comparable. Potlatch proposes to limit the depreciation adjustment to distribution plant. Tr. pp. 1203, 1204. Potlatch recommends a $2.1 million decrease in the Company's recommended $2.4 million depreciation adjustment. Tr. p. 1222.

The Company by way of rebuttal contends that absent planned deregulation and divestiture, the logic of Potlatch's depreciation argument fails and should be rejected. Avista, the Company states, has not proposed any divestiture in this case and has spoken publicly against forced divestiture. Additionally, it is noted that neither this Commission nor the Idaho Legislature have come forth to promote electric deregulation and divestiture of utility generating assets. Tr. p. 144. The Company also notes that rate base in Idaho is calculated on the basis of original cost, not market cost or replacement cost. Potlatch, it states, illogically wants depreciation to be influenced by market value while regulated rates are being set using original cost. Tr. p. 146.

Findings:

The Commission has reviewed and considered the Company's proposed increase in depreciation rates and expense, its related depreciation study, Staff's proposed adjustments to depreciation rates and expense, Potlatch's arguments regarding depreciation and the Company's rebuttal.

The Company's depreciation rates were last changed in 1990. The established rates were tentative and subject to later rate case justification. We note that the Company in this case is not proposing a change in its depreciation methodology. Tr. p. 611. We find the underlying depreciation methodology utilized by the Company to be sound and not in need of change.

The depreciation rates and resultant changes in expense we find to be reasonably based on updated information or change in accounting estimates (study and analysis of historical retirement experience, salvage and cost of removal experience and determination of updated unit remaining lives and net salvage factors). Tr. pp. 611, 633. The Company accepts Staff's proposed depreciation adjustments, which we also find to be reasonable. Tr. p. 133. The schedule of final depreciation rates that we adopt is that depicted in Staff Exhibit 115. However, in light of the testimony regarding Centralia and its likely sale, we find it reasonable in this case to reject the proposed change in terminal net salvage percentage related to Centralia (25.9%). Reference Exh. 211, p. 2, excerpt from Deloitte and Touche Depreciation Study. The rates for Centralia should remain at the existing rates reflected in Exhibit 15, p. 1.

Normalized Net Power Costs

Avista in this case proposes utilizing 60 water years (1927-28 to 1987-88) for normalization of power supply costs in its power supply model. Tr. p. 1207.

Potlatch contends that shorter periods e.g., 50-year, 40-year, 30-year and 20-year averages all produce lower test year net power supply expense estimates than Avista's 60-year average. Tr. p. 1207; Exh. 206. Potlatch recommends a 30-year average reducing net power supply expenses from $42 million as proposed by Avista to $37.088 million, with a related resultant decrease in revenue requirement of $1.6 million. Tr. pp. 1211; 1222.

Avista on rebuttal notes that in the current case, as well as in previous cases, the Company has consistently used the full water record from the regional Northwest Power Pool hydro regulation studies for the normalization of power supply costs. Tr. p. 424. The Company specifically notes that water record data prior to 1928 is not available for the Clark Fork River, where the majority of the Company's hydroelectric generation resides. Tr. p. 428. Absent credible and conclusive studies demonstrating an identified trend or cycle in water record data, which the Company contends has not been presented, Avista argues that the use of the maximum amount of reliable data will produce the best estimate. Tr. pp. 393, 394, 417-419. The Company charges Potlatch with "selectively choosing" water records to manipulate normalized power supply cost. Tr. p. 425.

Findings:

The Commission has reviewed and considered Potlatch's objection to the Company's use in its power supply model of the most recent 60 water years included in the Northwest Power Pool's regional study (1927-28 to 1987-88). While we would prefer to also capture the most recent ten-year period, we understand that the updated study has not yet been completed and indeed may not be available until the year 2003. Accordingly, we are satisfied that the Company's use of the Power Pool's present 60-year study presents us with the best regional data for the Company's hydro generation resources. We have been presented with no persuasive reason to require that the Company abandon the use of its Power Pool data in its power supply model. We also find it more reasonable to use the full 60-years of data as opposed to a selected shorter period.

Rate Base

Avista in its Application proposed a pro forma rate base of $360,534,000 for the Idaho jurisdiction. Reference Exh. 11, p. 8. Based on evidence presented by Staff, Avista accepted a depreciation related adjustment to rate base resulting in an increase of $651,000 for a revised Company proposed rate base of $361,185,000. Reference Company Rebuttal Exh. 24, Sch. 1, pp. 1-7.

Staff calculates an adjusted rate base of $360,546,000. The difference in Company revised and Staff adjusted rate base is a Staff proposed $639,000 line extension (CIAC) adjustment. Exh. 118, pp. 1, 2. Potlatch proposes no change or adjustment in Company proposed rate base. Reference Exh. 208.

Findings:

The Commission has reviewed the Company's revised and Staff proposed rate base calculations. Because in our discussion of operating assets–pro forma adjustments, we find Staff's CIAC adjustment to be reasonable (including related rate base) we find a 1997 total rate base of $360,546,000 to be just and reasonable.

Capital Structure

Avista proposes a capital structure based on outstanding debt, preferred securities and common equity balances at December 31, 1997, adjusted for known and measurable changes through September 30, 1998. The Company has elected to reduce common equity by the amount of its equity investment in certain non-regulated subsidiaries, resulting in capitalization of 48.030% long-term debt, 3.958% short-term debt, 10.588% preferred securities and 37.424% common equity. Exh. 5, Sch. 6, p. 1. Staff agrees with the Company's proposed capital structure. Tr. p. 1126; Exh. 122, Sch. 14. Potlatch expresses no opinion.

Findings:

The Commission adopts the capital structure proposed by Avista and accepted by Staff as appropriate and reasonable for calculating the Company's overall rate of return. We also recognize and appreciate the willingness of Avista to adjust the capital structure for investment in non-regulated subsidiaries.

Cost of Capital and Rate of Return

Debt and Preferred Equity

The Company calculates its embedded costs of debt and preferred equity associated with its proposed capital structure to be 8.011% for long-term debt, 6.255% for short-term debt, 8.113% for preferred trust securities and 8.151% for preferred stock. Exh. 5, Sch. 6. Staff accepts the Company's calculation of debt and preferred costs. Tr. p. 1126; Exh. 122.

Findings:

The Commission finds the debt and preferred costs proposed by Avista and accepted by Staff to be reasonable.

Common Equity/Equity Adder

The Company, 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, and is primarily an attempt to quantify a rate of return required by investors for that particular investment. Avista proposes a range for equity return of 11.25–12.25% and requests a rate of return of 11.75% on the common equity portion of its capital structure. Tr. p. 213.

Staff proposes a lower range for equity return of 10.25–11.25%, recommends a return on equity of 10.75%. Exh. 122, Sch. 14; Tr. p. 1107. Potlatch states that there has been a dramatic drop in cost of both equity and debt since 1986 and suggests that a more reasonable rate of return for equity is in a range of 10.4–10.9% (estimated revenue requirement impact of ($2.4 million)). Tr. p. 1221, Exh. 208.

The Company in this case recommends that an equity adder of 25 basis points be added to the equity return of Avista to recognize innovative management and strategic initiatives. Tr. pp. 124-126, 214. Without such an award, the Company contends that there is not sufficient differentiation in rate setting between a well-managed and a poorly-managed utility. Tr. p. 112.

Commission Staff agrees to the Company proposed equity adder. In doing so, Staff contends that the adder should not necessarily be viewed as a reward for past exemplary performance but as an incentive to continue programs and processes that lead to noted qualities and initiatives with continued betterment of performance as the goal. Avista is making improvements, Staff contends, and deserves recognition for those improvements. Tr. p. 1128. In determining the appropriateness of such an award, however, areas of noted concern that must also be weighed by the Commission, Staff contends, are: 1) the Company's failure to comply with Commission Order No. 23071 (1990) by not providing annual updated line extension costs for Schedule 51 construction; and 2) the Company's failure to comply with the Customer Information Rules requirement of individual customer notice of rate changes (e.g., PCA tracker adjustments). Reference IDAPA 31.21.02.102; Tr. p. 1129. The Company characterizes its omissions as administrative oversights. Tr. pp. 140, 152, 901, 902, 904.

Findings:

Different methodologies exist 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 ascertain a rate of return on common equity at a point sufficiently attractive that free-market investors will consider purchasing common equity shares in a 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 market place is determined by many variables, including management decisions, weather, streamflow conditions, and a host of separate economic factors.

The Commission in previous cases has relied on DCF and comparable earnings methods to determine an appropriate rate of return on common equity. The DCF analysis utilizes the dividend rate, stock price and expected growth rate of a company to quantify the return required by the investor. The comparable earnings method evaluates returns earned by other companies, including utilities, to quantify an investor's expected return, taking into account the risk associated with the 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.

The DCF methodology was used by both Avista witness Avera and Staff witness Carlock. While both witnesses agree in this case that a constant growth DCF methodology is not appropriate, they do not necessarily agree on the reasons. Potlatch's witness, Dr. Peseau, provides no DCF analysis but presents a debt to equity cost relationship analysis comparing 1986 debt costs and interest rates to today's, concluding that comparable interest rates today are 200 to 250 basis points below the September 1986 levels. Tr. pp. 1218, 1220, 1253, 1254.

Avera contends that future growth equally weights regulated and non-regulated future growth. Tr. p. 297. Carlock states that a constant growth method is not reasonable to use for Avista because the dividend change for Avista minimizes the benefit of historical trends and that growth projections for the next three years are not representative of ongoing growth due to the exchange offer. Tr. p. 1123. Carlock has not specifically weighted the growth rate for expected changes in regulated and non-regulated operations.

We are not inclined to accept Avera's methodology as it can put too much weight on deregulated operations without assuring that regulated operations are not paying an excessive share of investor growth expectations for deregulated operation. We are also uncomfortable with the projections Avera uses through 2008 to develop his recommended return requirements. We accept Carlock's two-stage methodology, as it does not focus on non-regulated growth. It is also for this reason we decline to accept Avera's added risk premium that he claims is associated with the lower common equity ratio used for regulatory operations. Tr. p. 213. We agree with Carlock that non-regulated operations must bear the equity return requirements caused by non-regulated operations. There is insufficient evidence in this record to demonstrate that this segregation and assignment of responsibility for required returns has occurred. With this in mind we authorize a return on equity of 10.75%. The 10.75% is within the range of reasonableness recommended by Carlock (10.25% - 11.25%) and also within the range Peseau indicates is reasonable (10.4% - 10.9%). We have chosen a return at the midpoint of the Staff recommended range. The overall rate of return authorized is 8.979% as shown in Appendix B to this Order.

The Commission recognizes that Avista has achieved excellence in many areas of utility performance including competitive efficiency, business excellence and innovation, and customer service. The Company has also pioneered industry activities including pilot customer choice programs, a non-bypassable distribution charge for conservation, a fuel-switching program, and a collaborative model for hydro relicensing.

However, while it is obvious that the Company is doing many things well and receiving deserved recognition within the industry, as regulators we cannot ignore the instances cited in this Order where the Company has failed to follow its tariffs and has ignored express

Commission directives and/or rules. The Company notes that "the regulatory compact expects management competency." Tr. p. 113. It is suggested that a minimum standard of management competency is compliance with Company tariffs and Commission Orders and rules. We encourage the Company to pay greater attention to the details of regulatory compliance. The Company should consider such compliance as a threshold qualification for any adder consideration. In this case we decline to include an equity adder.

Summary of Adjustments to Test Year Revenue, Expenses and Rate Base

Considering all of the evidence presented, and including all adjustments, we find total Idaho jurisdiction operating revenues for the 1997 test year in the amount of $187,136,000, and total Idaho jurisdiction operating expenses and related adjustments in the amounts of $154,762,000 for a Idaho jurisdiction net operating income of $32,374,000 to be reasonable and just. After all adjustments we find a 1997 total rate base amount of $360,546,000 to be just and reasonable. Appendix A to this Order shows the Commission's findings on rate base and net operating results for the test year.

Calculation of Revenue Deficiency

Having determined 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	$360,546,000
Rate of Return	8.979%
Net Operating Income Requirement	$ 32,374,000
Operating Income	$ 26,435,000
Income Deficiency	$ 5,939,000
Incremental Tax Multiplier	1.571042
Revenue Deficiency	$ 9,330,000

Appendix B to this Order shows the calculation of cost of capital and calculation of revenue deficiency for Avista.

Cost-of-Service Study

A cost-of-service allocation study allocates total cost-of-service (i.e., the revenue requirement) to a series of functional costs and then to classes of customers in accordance with recognized principles and generally accepted procedures in order to obtain an indication of the relative cost responsibilities of each class of customers.

The basic cost-of-service (COS) methodology, peak credit method, used by the Company in this case is the same as the COS study filed in its last rate case with two exceptions:

1. Distribution costs are classified to customer and demand by the Basic Customer Method in this case, whereas in 1986 the Minimum Distribution Method was used.

2. Administrative and general costs are directly assigned to function where possible and the remaining general costs are included with the distribution function and classified 40% to energy and 60% to customer. In the 1986 case most administrative and general costs were allocated by the sum of other operating expenses or plant which implies a functional allocation based on the components of the sums. Tr. p. 744; Exh. 17.

The Company notes that its cost-of-service study in this case differs from the Idaho unbundling study methodology in the treatment of administrative and general costs and some refinements to the primary/secondary categorization of distribution plant. Tr. p. 777.

Staff believes that the two changes in the Company's COS study tend to improve COS results. Tr. p. 1161. Staff notes that changes to cost-of-service methodology shift costs among classes and affect revenue requirement responsibility. The effects of the changes in this Company's current COS study are to increase costs of Residential, General Service and Pumping classes, and to decrease costs for Large General Service, Extra Large General Service and Lighting classes. Tr. p. 1154. The rate impact, Staff contends, is softened by the Company proposal in this case to only move one-third of the way toward full cost-of-service rates. Tr. pp. 1153, 1155. Staff supports the Company's proposal. A more aggressive move toward full cost-of-service in rate design, Staff contends, would produce unacceptably large rate increases. Tr. p. 1155.

Staff accepts the Company proposed cost-of-service methodology. Tr. p. 1154. Staff notes however that there is no such thing as one and only one correct methodology. Each method has perceived advantages and disadvantages for each class of service. See Exh. 26, relative rate of return (ROR) by class.

Potlatch contends that the Company's cost-of-service study is flawed and that it departs from prior Commission positions. Tr. p. 1172. Potlatch addresses the Company's classification and allocation of distribution costs, the demand allocators for both generation and distribution costs, classification of transmission costs and the allocation of conservation costs. Correcting for the perceived flaws in the Company's cost-of-service study, Potlatch concludes that Schedule 25 customers are currently paying rates that cover their cost of service. Tr. pp. 1173, 1246; Exh. 209, l. 58.

Avista proposes to classify and allocate distribution, transmission and generation costs, Potlatch contends, in such a way as to penalize high load factor customers. Tr. p. 1224. Avista in this case proposes a move from the Minimum Distribution System (MDS) method to the Basic Customer Method (BCM). Tr. p. 1226. MDS, Potlatch contends, produces a fairer classification of distribution costs. The Avista proposal to switch to BCM (used in Washington), Potlatch contends, under-estimates the customer component and over-estimates the demand component of distribution costs. The inherent bias in this method, Potlatch contends, greatly exaggerates the costs to high load factor customers. Tr. pp. 1228, 1248.

Regarding demand allocators, Potlatch notes that Avista proposes the use of an average 12 CP allocator to allocate production and transmission demand-related costs. Potlatch disagrees. Potlatch recommends that demand cost allocation be made on the basis of customer class contribution to system peak demand, which occurs in January (1CP). Exh. 209, Tr. pp. 1233-1236.

Avista by way of rebuttal characterizes the changes proposed by Potlatch to the cost-of-service methodology as designed to selectively shift costs away from the Schedule 25 customer group and incidentally on to residential customers. Tr. p. 775. Addressing Potlatch's contention that Avista is departing from the only Commission approved method of classifying distribution costs, Avista notes that PacifiCorp's UP&L jurisdiction utilizes essentially the same Commission approved classification method the Company proposes. Tr. pp. 778, 779. Potlatch disputes the Company's representation or inference that PacifiCorp in not choosing the minimum distribution system approach had adopted or was using the basic customer method. Instead Potlatch contends that PacifiCorp follows a facilities or engineering approach. Tr. p. 1250. Addressing Potlatch's proposed use of single peak allocator (1 CP) to a monthly average allocator (12 CP), Avista contends that a 12 CP allocator is more reasonable because (1) single peak allocators are subject to weather-related variability, (2) capacity concerns are important throughout the year, not just at a single peak; and (3) monthly peak allocators approximate demand billing determinants thereby capturing the annual contribution when measured by kW month. Tr. pp. 779, 780.

Findings:

The Commission has reviewed and considered the Company's cost-of-service allocation study, Potlatch's critique of same and Staff's support of the study. Dr. Peseau, on behalf of Potlatch, correctly characterizes cost-of-service studies as a balance of art and economic principles. Tr. p. 1224. It is only natural, Dr. Peseau contends, for each rate class to want to pay the lowest possible power bills and to avoid subsidizing other classes. Tr. p. 1224. Cost-of-service, however, is only one of many factors to be considered by this Commission in tariff design; there is no required correlation. The Company and Staff correctly note that COS methodology changes can have profound impacts on cost responsibility. We find the two changes proposed by the Company in its COS methodology, however, to be improvements and reasonable. We reject Potlatch's recommended changes to cost-of-service methodology and accept the Company's submitted cost-of-service allocation study .

Rate Design – Class Revenue Allocation

Having determined the Idaho jurisdictional revenue requirement, we must now determine the appropriate revenue requirement for each customer class. Based on its cost-of-service study the Company proposes a one-third move to full cost-of-service, a move which Staff supports. Tr. p. 105. The primary goal of the Company's rate spread is to move the rates of return of the individual schedules closer to the Company's overall rate of return. Tr. pp. 831, 832; Exh. 21.

The Company in this case proposes three structural changes to its electric customer class rates, two in the residential class and one in the pumping class.

<u>Residential Service – Schedule 1</u>

> For the residential class the Company proposes to collapse the existing three-block inverted energy rate structure to a two-block inverted energy rate structure (with the break point at 600 kWhs) and to move from a customer minimum ($8.50/mo.), which includes 203 kWhs of energy, to a basic charge ($5.50), which includes no energy.

Pumping Service – Schedule 31

> For the pumping class schedule which provides service for pumping water (and water effluents) for irrigation, municipal systems and other purposes, the Company proposes to add a $6.00 basic charge where there currently is none. The proposed charge, the Company contends, will recover approximately 82% of related service costs, a meter, meter reading and billing. Tr. pp. 861, 862.

Tr. p. 1156; Exh. 26, p. 3.

Staff accepts the Company proposed structural changes except as to the residential basic charge amount. Tr. p. 1157. Regarding the residential basic charge, Staff recommends a $4.00 basic charge as opposed to the Company proposed $5.50. Staff contends that a $4.00 basic charge allows the Company to introduce residential customers to a new type of charge, recovers a reasonable portion of its embedded costs through a fixed fee, reduces the high percentage increase on low consumption customers, and is consistent with other basic charges found in Avista's tariffs (e.g., $4.30 residential basic charge MOPS II; $4.00/mo optional seasonal chg—Residential Sch 1). Tr. p. 1089. A $4.00 basic charge also, Staff contends, comports with Avista unbundling information identifying a total cost for metering, meter reading and billing for small customers of $3.87/month. Tr. p. 1090.

The Company contends that a $5.50/month basic charge for residential customers is more reasonable and fair and will still provide only partial recovery of the average embedded costs for serving customers, i.e., service line, meter, meter reading and billing costs. Tr. p. 107. The Company calculates the total customer allocated cost at $14.96/customer. The Company on rebuttal notes that based on survey results the average monthly electric consumption for gas-heat customers is approximately 800 kWh/mo, whereas the average monthly electric consumption for non-gas heat customers is approximately 1200 kWh/mo. Tr. p. 878. The Company's documentation and testimony, as indicated by Staff, shows that 11,100 of its Idaho customers are in households whose annual income falls below $15,000. The number of those customers whose primary heat source is electricity is 5,198. Of those, 3,500 customers received energy assistance during 1998. Tr. p. 1092.

Speaking to the justness and reasonableness of the proposed increase, Senator Keough in her comments, indicated that northern Idaho was a troubled economy; that the most recent unemployment figures for Bonner County show a 9.8% unemployment rate, over double the statewide average. In fact, she states that across the area proposed for the rate increase are the counties with the highest unemployment rates in the state. Tr. p. 553. The unemployed, the underemployed and the business sector, she maintains, can ill afford the proposed increase. Tr. p. 554. Low power rates, while the envy of others, she notes, do not reflect the absence of and the struggle to obtain adequate roads and infrastructure. This is an area of increasing and documented numbers of people lining up at local food banks. How, can this reality, she queries, be squared with a company that is paying its CEO a huge salary asking for more money. Tr. p. 555. It is reported, she states, that the Company is making only 7% on its investment and is asking for a 9-10% return. Where, she asks, can the public sign up for such a return on savings? Tr. p. 556. Why should the people in her district, she queries, be forced to choose or in fact perhaps not be given any choice between feeding their families and paying their power bill? Tr. p. 556.

The present and proposed electric rates are reflected in Avista Exhibit 26, p. 3 and Staff Exhibit 127. The Company in its Application proposes the following changes:

General Service-Schedule 11

To recover additional fixed system costs, the Company is proposing an increase in the basic charge for General Service – Schedule 11 customers from $4.00 to $6.00. Tr. pp. 855, 856; Exh. 26, p. 3, Exh 21, p. 5. Additionally, the Company proposes to increase the Schedule 11 demand charge for kW in excess of 20 kW/month from $3.15/kW to $3.50/kW. Tr. p. 856.

Large General Service—Schedule 21

For the Large General Service Schedule 21 tariff, the Company is proposing to increase the monthly minimum charge from $200 to $225 per month and the present demand charge from $2.30/kW to $2.75/kW. To provide additional economic incentive for a new customer to take service at primary voltage, the Company is also proposing to increase the present primary voltage (11 kv or higher) discount from $.10/kW to $.20/kW. Tr. p. 857. Primary voltage customers are required to own and maintain electric facilities (step-down transformers, conductor, etc.) on their side of the meter. Tr. pp. 857, 858. Presently, the Company serves only 18 out of 1,700 total Schedule 21 customers at primary voltage. Tr. p. 859.

Extra Large General Service—Schedule 25

The Company's Extra Large General Service Schedule 25 tariff requires a minimum monthly demand level of 2500 kilovolt-amperes (kva). Eleven customers (14 account metering points) are served under the schedule. The Company is proposing to increase the monthly minimum charge from $5,500 to $7,500 per month for the first 3,000 kva or less (an implied demand charge of $2.50 per kva), and to increase the demand charge for all kva in excess of 3,000 from $1.10/kva to $2.25/kva. The proposed demand charge, the Company contends, will provide customers with a more reasonable indicator of demand-related costs and encourage them to further improve their load factor. Also proposed is an increase in the annual minimum charge from $361,350 to $419,230 and an increase in the primary voltage discount from $.10/kva to $.20/kav. Tr. pp. 859-861.

Street and Area Light—Schedules 41-49

Street and Area Light schedules contain monthly fixed charges for different light types and sizes, as well as pole types. The Company proposes a uniform increase to present rates and charges. Tr. p. 863.

Findings:

The Commission has considered the proposals and testimony of the parties regarding rate design and class revenue allocation. The Commission finds that moving all class revenue requirements to the levels suggested by the Company and Staff would be unreasonable. In Order No. 28078 in this case, we recognized having received in excess of 250 petitions, letters and/or E-mail comments from Avista customers. The customers relate individual accounts regarding the Company's Idaho service territory, its depressed timber, mining and agricultural industries, and the pervasive level of poverty, unemployment and underemployment including the impact of the proposed increase on themselves, their families, their communities and their businesses. Important interests in rate stability and continuity preclude adopting the extremely large double digit shifts in revenues from one class to another that were requested. In addition, we recognized that the results of cost-of-service studies are not so precise that the determination of appropriate revenue shifts is an exact certainty. The number of years between examinations of cost-of-service and revenue allocation issues for the Company has allowed several classes (Residential

Schedule 1 and Extra Large General Service Schedule 25) to drift a considerable distance from full cost-of-service rates and requires gradual, incremental moves to cost-of-service rates. We approve a two step move to accomplish the Company's proposed one-third move to full cost-of-service, a 20% move the first year reflected in the rates approved by this Order, and an additional 15% move to begin one year from the date of this Order.

The Commission also finds Staff's proposed $4.00/month basic charge for residential customers to be a reasonable transition step away from the existing customer minimum that includes an energy allowance. The resulting revenue allocation and tariff rates that we approve in this case are depicted in Appendices C and D to this Order.

MISCELLANEOUS

DSM / Electric Energy Efficiency

The Demand Side Management (DSM) or electric energy efficiency programs of Avista are described in its electric Tariff Schedule 90. The programs are presently financed by a 1 ½ % energy surcharge (electric Tariff Schedule 91). The Company's year end 1998 estimated energy savings for completed projects (31,452,304 kWh) and related expenditures for these program of $4,461,775 are set out in Company revised Exhibit No. 12. Tr. p. 1007. The cost effectiveness methodology used by the Company in assessing its energy efficiency programs is described in Company Exhibit No. 13.

Noting that the Company's energy efficiency expenditures differ by class and that DSM related expenditures for Schedule 25 are only 3.3% of total, Potlatch objects to a uniform allocation of DSM expenditures during periods of relative resource surplus and recommends that DSM program costs be allocated in direct proportion to the expenditures made on each class. Tr. p. 1244. During periods of surplus Potlatch contends that no cross benefits or savings accrue to non-participants. Tr. p. 1244.

Disagreeing with Potlatch, the Company and Staff contend that all of the Company's customers benefit from cost effective DSM programs, albeit with program participants receiving a larger share of the benefits. Tr. pp. 150, 1009. Staff further contends, that in addition to energy and cost savings there are often non-energy, societal benefits, (such as greater productivity, cleaner air and reduced need for damming rivers) associated with reduced or at least more efficient energy usage. Tr. p. 1009.

Regarding the Company's DSM expenditures from March 1995 to December 1998, Staff contends that the Company has otherwise engaged in prudent planning, implementation and evaluation. Tr. pp. 1017, 1018. The Company, Staff states, has created both internal and external organizations in its efforts to optimally design, implement, coordinate, verify and evaluate its DSM programs. It is a dynamic, not a static process, Staff contends. Tr. p. 1017. Also assessed to be reasonable and prudent by Staff are the Company's jurisdictional expenditures to the Northwest Energy Efficiency Alliance (NEEA) of $155,000 for 1997 and $310,000 for 1998, or $465,000 total. Tr. pp. 1018, 1019. The Company has requested and Staff recommends a Commission finding that Company DSM expenditures, including NEEA, through December 1998 have been prudently incurred. Tr. pp. 1008, 1011.

Staff quantifies the balance of DSM revenues beyond expenses incurred by Avista and recommends that 10% annual interest be imputed on past account balances as specified in the Company's 1994 DSM tariff rider application and that the rider surcharge be reduced by one-third to 1.0%. Tr. p. 1008. Staff notes that Avista has collected $5,330,274 from its Idaho customers through its DSM surcharges. This is $868,499 or 20% more than it has spent for its conservation and efficiency efforts in Idaho. Tr. pp. 1011, 1012. Staff contends that it was never intended for such a large deferred balance to be carried. Reference Company Application Case No. WWP-E-94-10/WWP-G-94-5 Attachment D, ¶4 Tariff Rider Implementation:

> As the DSM programs in Schedule 91 and 191 are modified over time, the DSM tariff rate would also be adjusted, up or down, to match funding with DSM program costs and to keep the deferred balances as close to zero as possible.

Tr. p. 1102; Exh. 130.

Regarding Staff's recommendation that 10% interest be imputed to the DSM balance, Staff notes that such was the Company's proposal in the DSM tariff rider application, "that 10% annual interest be added to the balance of the one month lagged differences between revenue and expenses." Exh. 130; Tr. pp. 1012, 1013. Staff computes that $189,000 in interest should be added to the end-of-year 1998 DSM balance of $868,498 bringing the balance up to approximately $1.06 million. See revised Exh. 131. Staff estimates that an additional $60,000 of interest will have accrued by June 30, 1999. Tr. p. 1013. Based on projected extension of past average revenues, expenditures and interest rate, Staff estimates that at the end of 2003 there will be a positive balance of $3.2 million in the DSM tariff rider account. Exh. 131; Tr. p. 1013.

Staff therefore recommends that the DSM tariff rider energy surcharge be reduced in this case by one-third to 1.0%. Tr. p. 101

The Company opposes a reduction in the present funding level noting that the prudence of DSM expenditures is not being challenged; DSM programs and proposed funding levels were and continue to be the result of a formal, extensive region wide collaborative process called the External Energy Efficiency Board (Triple E Board); and that an extension of the DSM Sch. 91 tariff rider at the present 1½% level was most recently approved in November 1998 in Order No. 27794. Tr. pp. 147, 148, 197, 198.

Avista in rebuttal contends that "the Company has always planned to maintain a surplus of funds in the DSM balance account" stating that many DSM projects in the commercial and industrial sectors require over a year to build out and, ultimately fund, and that it is necessary and prudent to maintain a positive balance. Tr. pp. 148, 195, 656. The Company agrees with Staff that some level of interest should be credited to Schedule 91 revenues but suggests rather than the 10% interest rate proposed and approved in the DSM Tariff Rider Application that the amount be 6%, the 1998 interest rate on Idaho customer deposits, and that the amount be offset by corporate service expense (floor space, telephone usage, and the like) as well as programmable lease investments. A 10% interest rate would result in an interest adjustment of $124,565. A 6% interest rate over the life of the rider through 1998, would provide an interest adjustment of $71,422. Tr. p. 656; Exh. 24, Sch. 2, p. 2.

As per its underlying Application in Case No. WWP-E-94-10 and related Commission Order, Avista is required to notify customers of the DSM surcharges once a year. The Company, Staff notes, has not being doing this. Reference Exh. 129 "Each year the rider will be shown in the annual How to Calculate Your Bill brochure." Order No. 25917, Stipulation ¶8, Case No. WWP-E-94-10. Tr. p. 1011.

Staff also recommends a change in how Avista evaluates the cost effectiveness of its programs. Tr. p. 1008. Staff notes that the Company does not explicitly estimate base line activity that would have occurred absent each of its programs. Staff contends that such an effort should be undertaken. Doing so, Staff states, would be consistent with how the NEEA will evaluate its programs, programs that are funded in part from Avista's surcharges. Tr. pp. 1015, 1016. Avista, Staff contends, does not believe estimating base line activity would be a prudent allocation of its resources and instead of hazarding guesses about such, it carefully monitors its programs and suggests modifying or dropping those that show only marginal benefit/cost ratios. Tr. pp. 1015, 1016.

Findings:

At a time when many electric utilities were discontinuing investment in DSM, Avista proposed a non-bypassable distribution charge to fund energy efficiency. This Commission continues to support the Company's efforts and investments in conservation. We find that the Company's DSM investment benefits all of its customers, both participants and non-participants. Prudent conservation continues to make sense from both a societal, environmental and economic perspective. As indicated in prior Orders, it is the Company's obligation in a rate case to demonstrate the prudence of its conservation investment and our responsibility to ratepayers to determine that the Company has satisfied its obligation. In reviewing the Company's Schedule 90 DSM programs, identified costs and projected benefits we find that the Company has sufficiently demonstrated the requisite prudence and cost effectiveness of its DSM related expenditures. Reference Exh. Nos. 12, 13. We agree with Staff that the Company's evaluation of cost effectiveness could be improved by developing estimates of baseline activities that would occur without the DSM programs. We encourage the Company to pursue development of such a baseline estimate for future program offerings.

We also find the Company's 1997 and 1998 investments and participation in the regional Northwest Energy Efficiency Alliance to be prudent and of benefit to its customers. As reflected in our transcript referenced Idaho Power Order No. 27877 (Tr. p. 1019) "NEEA's efforts are directed to market transformation ... there is the expectation that through incentives and the establishment of governmental standards certain energy efficient products, services and consumer education will become available and, ultimately result in improved energy efficiency." At p. 10. This Commission does not find it necessary to assess the various programs and projects of NEEA on an individual project by project basis. Rather we find that it is appropriate to consider them as a whole.

The Company's underlying Application for Schedule 91 tariff rider approval (Case No. WWP-E-99-10) contained representations and commitments regarding interest accrual on deferred balances and required annual notice to customers. Despite a clear statement in the prior tariff rider application that the Company intended "to match funding with DSM program costs and to keep the deferred balance as close to zero as possible" — the Company now states "the Company has always planned to maintain a surplus of funds" in the account. Tr. p. 654.

It also appears from the record that the Company in administering Schedule 91 DSM surcharge monies has not been calculating the 10% interest on expended deferral balance amounts approved in the application. Despite no mention of it in the prior tariff rider application and no direct testimony submitted in this case, the Company now proposes to offset calculated interest amounts with "corporate service expense" and "programmatic lease investment." Exh. 24, Sch. 2, p. 2. The Company also requests that rather than using the stated 10% interest rate on DSM deferral balances that the Commission in this case authorize for calculation purposes the use of a lower 6% interest rate, or a link to the Commission approved interest rate for customer deposits currently at 5%. Reference IDAPA 31.21.01.106; Tr. p. 134

We find the Company's representations and recommended accounting changes to be inconsistent with the application approved by this Commission. We accept Staff's interest calculation on Schedule 91 deferred balances without offset or adjustment. We find that the appropriate interest rate going forward is the overall return authorized in this Order. Because it is the stated program intent to keep the current balance as close to zero as possible, we also find it reasonable to reduce the Schedule 91 energy surcharge rider from 1½% to 1%.

The Company is reminded that the Triple E Board is an advisory board and has no power to abrogate Company obligations and requirements pursuant to Commission Orders. Accordingly, the Company is reminded of its annual obligation to provide customers with DSM surcharge information.

CONCLUSIONS OF LAW

The Idaho Public Utilities Commission has jurisdiction over this Application and Avista Corporation dba Avista Utilities — Washington Water Power Division, an electric 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*.

This Commission has jurisdiction and authority pursuant to the above identified statute and rules to authorize and require Avista to reallocate its revenues among the customer classes, to change its rate components within the customer classes 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, IT IS HEREBY ORDERED and the Commission hereby authorizes Avista Corporation dba Avista Utilities—Washington Water Power Division to increase its revenues by $9,330,000 or approximately 7.58%. The Company is directed to file amended tariff sheets for rates and charges in compliance with the terms of this Order. The rate increase that we authorize is for service rendered on and after August 1, 1999.

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

THIS IS A FINAL ORDER. Any person interested in this Order may petition for reconsideration within twenty-one (21) days of the service date of this Order. 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 29th day of July 1999.

DENNIS S. HANSEN, PRESIDENT

MARSHA H. SMITH, COMMISSIONER

PAUL KJELLANDER, COMMISSIONER

ATTEST:

Myrna J. Walters
Commission Secretary

bls/O:wwpe9811_sw5

AVISTA UTILITIES - WASHINGTON WATER POWER DIVISION
PRO FORMA RESULTS
TWELVE MONTHS ENDED DECEMBER 31, 1997
(000'S OF DOLLARS)

Line No.	DESCRIPTION	A Re-state Company Pro Forma Total	B Total Adjustments	C State & Federal Tax on Adjustments	D Pro Forma Total	E Increase in Revenues & Related Exp.	F Pro Forma at Proposed Rates
	REVENUES						
1	Total General Business	$123,029	$0		$123,029	$9,330	$132,359
2	Interdepartmental Sales	$63	$0		$63		$63
3	Sales for Resale	$47,662	$0		$47,662		$47,662
4	Total Sales of Electricity	$170,754	$0	$0	$170,754	$9,330	$180,084
5	Other Revenue	$7,052	$0		$7,052		$7,052
6	**Total Electric Revenue**	$177,806	$0	$0	**$177,806**	**$9,330**	**$187,136**
	EXPENSES						
	Production and Transmission						
7	Operating Expenses	$30,339	($236)		$30,103		$30,103
8	Purchased Power	$53,813	$0		$53,813		$53,813
9	Depreciation and Amortization	$9,388	($576)		$8,812		$8,812
10	Taxes	$5,492	$0		$5,492		$5,492
11	**Total Production & Transmission**	$99,032	($812)	$0	**$98,220**	**$0**	**$98,220**
			$0		$0		
	Distribution		$0		$0		
12	Operating Expenses	$6,108	($504)		$5,604		$5,604
13	Depreciation	$5,007	($309)		$4,698		$4,698
14	Taxes	$2,060	$0		$2,060		$2,060
15	**Total Distribution**	$13,175	($813)	$0	**$12,362**	**$0**	**$12,362**
16	**Customer Accounting**	$3,720	$0		**$3,720**	$35	**$3,755**
17	**Customer Service & Information**	$2,970	$0		**$2,970**		**$2,970**
18	**Sales Expenses**	$131	$0		**$131**		**$131**
	Administrative & General						
19	Operating Expenses	$16,443	($610)		$15,833	$22	$15,855
20	Depreciation	$2,684	$0		$2,684		$2,684
21	Taxes	$44	$0		$44		$44
22	**Total Admin. & General**	$19,171	($610)	$0	**$18,561**	**$22**	**$18,583**
23	**Total Electric Expenses**	**$138,199**	($2,235)	**$0**	**$135,964**	**$56**	**$136,020**
24	OPERATING INCOME BEFORE FIT & SIT	$39,607	$2,235	$0	**$41,842**	**$9,274**	**$51,116**
	STATE INCOME TAX						
25	State Income Tax Expense	$1,442	$345	$33	$1,820	$137	$1,957
26	Amortized Investment Tax Credit		($154)		($154)		($154)
27	**Total State Income Tax**	**$1,442**	$191	$33	**$1,666**	**$137**	**$1,803**
	FEDERAL INCOME TAX						
28	Current Accrual	$5,204	($174)	$771	$5,801	$3,198	$8,999
29	Deferred Income Taxes	$3,248			$3,248		$3,248
30	Net Federal Income Taxes	$8,452	($174)	$771	$9,049	$3,198	$12,247
31	Amortized Investment Tax Credit	($23)			($23)		($23)
32	**Total Federal Income Tax**	**$8,429**	($174)	$771	**$9,026**	**$3,198**	**$12,224**
33	**SETTLEMENT EXCHANGE POWER**	**$4,715**			**$4,715**	$0	**$4,715**
34	**NET OPERATING INCOME**	**$25,021**	$2,218	($804)	**$26,435**	**$5,939**	**$32,374**
	RATE BASE						
	PLANT IN SERVICE	$0					
35	Intangible	$5,850	$0		$5,850		$5,850
36	Production	$253,904	$0		$253,904		$253,904
37	Transmission	$84,372	$0		$84,372		$84,372
38	Distribution	$204,248	($1,152)		$203,096		$203,096
39	General	$33,672	$0		$33,672		$33,672
40	Total Plant in Service	$582,046	($1,152)		$580,894	$0	$580,894
41	ACCUMULATED DEPRECIATION	$170,993	($493)		$170,500		$170,500
42	ACCUM. PROVISION FOR AMORTIZATION	$1,616	$0		$1,616		$1,616
43	Total Accum. Depreciation & Amort.	$172,609	($493)		$172,116	$0	$172,116
44	GAIN ON SALE OF BUILDING	($940)	$0		($940)		($940)
45	DEFERRED TAXES	($47,963)	$671		($47,292)		($47,292)
		$0	$0		$0		$0
46	**TOTAL RATE BASE**	**$360,534**	$12		**$360,546**	$0	**$360,546**
					7.332%		8.979%

AVISTA UTILITIES - WASHINGTON WATER POWER DIVISION
REVENUE REQUIREMENT
TWELVE MONTHS ENDED DECEMBER 31, 1997
(000'S OF DOLLARS)

Line No.	Description	Commission Order Numbers
1	Commission Pro Forma Rate Base	$360,546
2	Commission Overall Rate of Return	8.979%
3	Net Operating Income Requirement	$32,374
4	Commission Pro Forma Net Operating Income	$26,435
5	Net Operating Income Deficiency	$5,939
6	Conversion Factor	0.636520
7	Additional Revenue Required	$9,330
8	Current Total General Business Revenues	$123,029
9	Percentage Revenue Increase	7.58%

CAPITAL STRUCTURE AND WEIGHTED COST OF CAPITAL

Line No.	Component	Ratio	Composite Cost	Rate of Return
1	Long-Term Debt	48.030%	8.011%	3.848%
2	Short-Term Debt	3.958%	6.255%	0.248%
	Total Debt	51.988%		4.096%
3	Preferred Securities			
4	Preferred Trust Security	8.032%	8.113%	0.652%
5	Preferred Stock	2.556%	8.151%	0.208%
	Total Preferred	10.588%		0.860%
6	Common Equity	37.424%	10.750%	4.023%
7	**Total**	100%		**8.979%**

APPENDIX B
ORDER NO. 28097

AVISTA UTILITIES - WASHINGTON WATER POWER DIVISION
REVENUE ALLOCATION
WWP-E-98-11
(000's of Dollars)
Twenty Percent Move Toward Cost-of-Service (First Year)

Line No.	Type of Service	Schedule Number	Revenue Under Present Rates	Increase (Decrease)	Revenue Under Commission Order	kWh's (000's)	Increase (Decrease) ¢ per kWh	Percent Increase
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Residential	1	47,978	4,545	52,523	1,013,773	0.448	9.47%
2	General Service	11	15,433	925	16,358	217,381	0.426	5.99%
3	Large General Service	21	32,741	2,505	35,246	671,250	0.373	7.65%
4	Extra Large General Service	25	10,796	1,076	11,872	355,596	0.303	9.97%
5	Pumping Service	31	2,039	146	2,185	40,857	0.357	7.16%
6	Street and Area Lights	41-49	1,514	133	1,647	11,728	1.134	8.78%
7	Potlatch Special Contract		3,839	0	3,839	83,787	0.000	0.00%
8	Other Revenue		8,751	0	8,751	0		
9	Total		123,091	9,330	132,421	2,394,372	0.390	7.58%

APPENDIX C
ORDER NO. 28097

AVISTA UTILITIES - WASHINGTON WATER POWER DIVISION
WWP-E-98-11
Present and Commission Ordered Electric Rates (First Year)

Residential Service - Schedule 1

Present Rates		Commission Ordered Rates	
First 600 kWhs	4.181 ¢/kWh	Basic Charge	$4.00
Next 700 kWhs	4.945 ¢/kWh		
All over 1300 kWhs	5.591 ¢/kWh	First 600 kWhs	4.419 ¢/kWh
		All over 600 kWhs	5.168 ¢/kWh
Minimum Charge	$8.50		

General Service - Schedule 11

Present Rates		Commission Ordered Rates	
Basic Charge	$4.00	Basic Charge	$6.00
Energy Charge	6.617 ¢/kWh	Energy Charge	6.849 ¢/kWh
Demand Charge:		Demand Charge:	
20 kW or less	no charge	20 kW or less	no charge
Over 20 kW	$3.15/kW	Over 20 kW	$3.50/kW

Large General Service - Schedule 21

Present Rates		Commission Ordered Rates	
Energy Charge	3.897 ¢/kWh	Energy Charge	4.134 ¢/kWh
Demand Charge:		Demand Charge:	
50 kW or less	$200.00	50 kW or less	$225.00
Over 50 kW	$2.30/kW	Over 50 kW	$2.75/kW
Primary Voltage Discount	10¢/kW	Primary Voltage Discount	20¢/kW

Extra Large General Service - Schedule 25

Present Rates		Commission Ordered Rates	
Energy Charge	2.685 ¢/kWh	Energy Charge	2.797 ¢/kWh
Demand Charge:		Demand Charge:	
3,000 kva or less	$5,500.00	3,000 kva or less	$7,500.00
Over 3,000 kva	$1.10/kva	Over 3,000 kva	$2.25/kva
Primary Voltage Discount	10¢/kva	Primary Voltage Discount	20¢/kva
Annual Minimum	$361,350.00	Annual Minimum	$419,230.00

Pumping Service - Schedule 31

Present Rates		Commission Ordered Rates	
First 85 kWh/kW	5.962 ¢/kWh	Basic Charge	$6.00
Next 80 kWh/kW	5.962 ¢/kWh		
All additional kWhs	4.181 ¢/kWh	First 85 kWh/kW	5.870 ¢/kWh
		Next 80 kWh/kW	5.870 ¢/kWh
		All additional kWhs	4.702 ¢/kWh

Rates Exhibit.xls 7/27/99 KDH