I. POLICY AND GOVERNING PRINCIPLES

The Commission in its Fifth Supplemental Order in the 1983 rate proceeding for Washington Water Power Company, Cause No. U-83-26 (Ex. 28), stated the purpose of a rate case, and the principles that govern the Commission's review of a rate filing, as follows:

> The ultimate determination to be made by the Commission in this matter is whether the rates and charges proposed in respondent's revised tariffs are fair, just, and reasonable pursuant to RCW 80.28.020. These questions are resolved by establishing the fair value of respondent's property in service, determining the proper rate of return permitted respondent on that property, and then ascertaining the appropriate spread of rates charged various customers to recover that return.
>
> The purpose of a rate proceeding is to develop evidence from which the Commission may determine the following:
>
> (1) The appropriate test period which is defined as the most recent 12-month period for which income statements and balance sheets are available. The test period is used for the investigation of the company's operations for the purpose of these proceedings;
>
> (2) The company's results of operations for the appropriate test period as adjusted for unusual events during the test period, and for known and measurable events following the test period;
>
> (3) The appropriate rate base which is derived from the balance sheets of the test period. The rate base represents the net book value of assets provided by investors' funds which are used and useful in providing utility service to the public;
>
> (4) An appropriate rate of return the company is authorized to earn on the rate base established by the Commission;
>
> (5) Any existing revenue deficiency; and
>
> (6) The allocation of the rate increases, if any, fairly and equitable among the company's ratepayers.
>
> RCW 80.04.130 places the burden of proving the proposed

> increase is just and reasonable upon the public service company proposing the increase.

Cause No. 83-26, Fifth Supplemental Order (January, 1984), page 7.

Stated most simply, the purpose of a rate proceeding is to set rates that are fair, just, reasonable, and sufficient. RCW 80.28.020. In reviewing a company's tariff filing, Commission Staff conducts an audit to determine which amounts included in the company's expenses and operating costs are appropriately to include in rates charged to the customers. In conducting the audit, and considering which expenses are allowable for ratemaking purposes, Staff obtains guidance from prior decisions of the Commission.

It is not Staff's goal to reach the lowest possible revenue requirement, and thus reduce the company's request for a rate increase. But by the same token, Staff is not at liberty to ignore the relevant data. Staff cannot, as the Company has suggested, simply discard calculations based on evidence and replace them with what "the average guy on the street will look at from a gut check as to what's fair." Nor can Staff base its recommendations on an undefined, abstract "rule of reason, you know, what looks fair." (TR 2015.) Avista invites the Commission to set aside Staff recommendations, which it derisively refers to as "micromanaged detail," in favor of adjustments increasing its revenue requirement. One can only imagine Avista's response if Staff's recommendations were founded simply on "what looks fair." It would vociferously object, and rightly so.

But Staff would not be performing its job properly if Staff members simply accepted the company request at face value without inquiry. In making recommendations concerning revenue requirement (and the component figures that go into the calculation), Staff does not challenge the wisdom of company decisions in the abstract, e.g., relating to salaries and expenses. Staff does, however, address the appropriate amounts or certain expenses to be included in rates, costs to be borne by ratepayers. When a company, such as Avista, is publicly traded and has a diversity of businesses, most of which are not regulated by the Commission, it is essential to determine what expenses are appropriately charged to the captive ratepayers as opposed to those persons who are in a position to choose, or not to choose, to do business with the company. But as the State Supreme Court noted in People's Org. for Wash. Energy Resources v. Utilities and Transp. Comm'n, 104 Wn. 2d 798, 810-11, 711 P.2d 319 (1985), disallowance of an expense for ratemaking purposes does not tell the company that it cannot choose to incur the expense; it only determines that shareholders, rather than captive ratepayers, must pay the expense.

In this docket, the Company has raised the specter of restructuring, competition, and divestment of power generation, as risks faced by the Company to justify its request for a higher rate of return than is recommended by Staff and Public Counsel. Yet, as Mr. Matthews noted in the Company's June 2000 conference to investors, restructuring in Washington is not imminent (Ex. 17, pages 6, 57). While these may be issues facing the energy utilities in other states, there are very few such risks in Washington or in Avista's service territory. For the most part, Avista remains a monopoly supplier of power. In fact, as Mr. Matthews testified (TR page 2011), in many instances where an alternative power supplier is available at lower cost, the customer chooses Avista as its supplier because of its large company status and more reliable sources of supply.

The Company also raises the specter of the risks to Avista the Company of the volatility of the costs of purchasing power on the short term market in the past several months. Several points are crucial here. First, the transactions to which Avista alludes did not take place during the test year and, therefore, are not included in the test year expenses. Second, these expenses are not known and measurable changes not offset by other factors. In fact, Avista's declarations to the financial community strongly suggest that these expenses are of a transitory nature. In its June 2000 conference call with investors, the Company assured that this was a short-term problem and would have no impact beyond October 2000 (Ex. 17, page 7). The rates to be set in this case will only take effect after October 2000, and thus the issues raised by the prices in the short-term energy market in May and June 2000 are irrelevant. Any consideration of the volatility of prices to purchase power on the short term market in May and June 2000 would be wholly speculative.

Finally, there is absolutely no need for the Commission to set rates based on speculation about the future. The Company has made a filing, pending in Docket No. UE-000972, to address recent changes in the costs of power. Those issues are properly addressed in that docket. To include the impact of these recent price swings in this case would reward the Company for its poor management decisions in those months, and potentially embed in rates a market aberration that may not recur. Furthermore, as Mr. Eliassen has recognized (Ex. 17, page 20), if the price of power does increase and stabilizes at a higher level than included in rates, then the Company can refile for changes in its rates based on the test year data showing the higher prices.

Given the potentially material effect that these issues may have in setting normalized power supply expense levels, as well as the recently announced intent to acquire significant generating resources, the Commission could also choose to order the Company to file a power supply case that reflects the new paradigm.

II. RESULTS OF OPERATIONS--CONTESTED ADJUSTMENTS

A. AVISTA'S REQUEST FOR THE KETTLE FALLS EQUITY "KICKER" SHOULD NOT BE APPROVED, AS IT DOES NOT MEET THE STATUTORY REQUIREMENTS

Avista has requested that the Commission allow it to recover a higher return on investment for the renewable energy from the Kettle Falls generating plant (Ex. 46, Direct Testimony of Thomas D. Dukich, pages 1-2). The Kettle Falls Generating Station (Kettle Falls) is a wood waste steam plant that was placed into the Company's rate base in 1983 (Ex. 46, page 8, lines 20-24). The justification cited by the Company for requesting this favorable treatment is that the plant is producing more power than it was originally designed to produce, and more than the Company and the Commission believed it would produce, at the time the plant was placed into rate base. Regardless of the plant's efficiency or production, it is not now eligible under RCW 80.28.025 for a higher return on investment for renewable resources. The statute is forward-looking in nature, and is not properly applied with hindsight. The statute states, in part:

> (1) In establishing rates for each gas and electric company regulated by this chapter, the commission shall adopt policies to encourage meeting or reducing energy demand through cogeneration as defined in RCW 82.35.020, measures which improve the efficiency of energy end use, and new projects which produce

> or generate energy from renewable resources, such as solar energy, wind energy, hydroelectric energy, geothermal energy, wood, wood waste, municipal wastes, agricultural products and wastes, and end-use waste heat. These policies shall include but are not limited to allowing a return on investment in measures to improve the efficiency of energy end use, cogeneration, or projects which produce or generate energy from renewable resources which return is established by adding an increment of two percent to the rate of return on common equity permitted on the company's other investment. Measures or projects encouraged under this section are those for which construction or installation is begun after June 12, 1980, and before January 1, 1990, and which, at the time they are placed in the rate base, are reasonably expected to save, produce, or generate energy at a total incremental system cost per unit of energy delivered to end use which is less than or equal to the incremental system cost per unit of energy delivered to end use from similarly available conventional energy resources which utilize nuclear energy or fossil fuels and which the gas or electric company could acquire to meet energy demand in the same time period. The rate of return increment shall be allowed for a period not to exceed thirty years after the measure or project is first placed in the rate base. RCW 80.28.025(1).

As noted above, the Kettle Falls plant was placed into the Company's rate base in 1983. The Company knew about the possibility of requesting an additional equity return in 1983 (Ex. T-84, Testimony of Thomas D. Dukich, page 27, lines 4-9; See also TR page 2073, line 20) but did not request it. The Company also did not request the higher return in its last general rate case in 1987 (TR page 353, lines 3-8; page 2074). This belated request does not meet the specific requirements of the statute and should be denied.

In the Commission's Fifth Supplemental Order in Cause No. U-83-26 (Ex. 28), the Commission considered the Company's request to place the Kettle Falls plant in its rate base. The prudence of the Company's construction of the Kettle Falls plant was specifically disputed during the hearing from which that order resulted. In its extensive discussion of the prudence of the investment and what portion, if any, of the costs of the plant should be placed in the Company's rate base, the Commission specifically stated that "the lower cost alternative in 1982 was the combustion turbine proposal." (Ex. 27, page 14). In addition, in its statement of the specific factors it weighed in judging how to treat the Company's request to include the Kettle Falls plant in its rate base, the Commission stated:

> (10) The board did not select a lower cost alternative (considering projected construction <u>and</u> operating costs) to Kettle Falls in January of 1982 and could have more rigorously studied the alternatives open to it; . . .

It is thus clear that, <u>at the time the plant was placed into rate base</u>, the Kettle Falls plant was not expected to produce power at a lower cost than similar conventional methods of producing power using fossil fuels. The Commission in Cause No. U-83-26 addressed the issue of placing the plant into rate base by allowing the Company to include in its rate base only a portion of the costs of constructing the Kettle Falls plant.

The Company is now requesting that it be allowed to add a 2% "kicker" on the rate of equity return it is allowed to earn on the remaining balance of the amount of its Kettle Falls investment that is included in rate base. The Company states in Ex. T-84, page 25, lines 18-21, that the remaining balance qualifies for an increased level of equity return under RCW 80.28.025 because the Commission in U-83-26 allowed only the level of expense equal to the least cost alternative to be placed in rate base, concluding that the 90% of the costs of the Kettle Falls plant that the Company is allowed to recover on was prudent and the least cost alternative. Herein lies the crux of the issue. RCW 80.28.025 specifically allows favorable treatment to be given to power production plants using alternative forms of energy if ". . . at the time they are placed in rate base, are reasonably expected to save, produce, or generate energy at a <u>total</u> incremental system cost per unit of energy delivered to end use. . . ." [Emphasis added.] The <u>total</u>

incremental cost, not 90% of the total cost, must be "less than or equal to" the least cost alternative.

The Company also states that there have been efficiency gains since the plant went into service that make the facility more cost effective (Ex. T-46, page 8, line 22, through page 9, line 8). However, again, the statute specifically requires that the plant must be the least cost alternative at the time it is placed into the Company's rate base, not some 16 years later. The statute was designed to provide an incentive to companies to build alternative means of power generation if they are more cost effective than other means. To allow the Company to begin collecting a higher return on its investment in the Kettle Falls plant long after it was constructed and placed into service does not meet the purposes for which the statute was enacted.

The Company also argues that the additional equity return should be allowed because the Washington State Department of Revenue allowed the Company a tax credit under RCW 82.16.055 (Ex. T-46, page 9, lines 16-22), which states essentially the same requirements as RCW 80.28.025. However as noted by Mr. Parvinen in his testimony (Ex. T-608, page 18, lines 3-18), the Department of Revenue seems to have either been unaware of this Commissions' decision in U-83-26, or specifically ignored it, when it issued its order in 1991. The Washington Utilities and Transportation Commission was not a party to the Department of Revenue case and the finding of the Department of Revenue in its Determination No. 91-047 (Response to Bench Request No. 1) appears to be directly contrary to this Commission's earlier determination that the Kettle Falls plant was not the least cost alternative. This conclusion seems to be based at least in part on the failure of the Department of Revenue's Audit Division to locate a similarly available lower cost alternative versus placing the burden of proof on the Company.

The Kettle Falls plant did not meet the statutory criteria for adding a two percent increment to the rate of return for the plant at the time it was placed into the Company's rate base, and the request should be rejected.

B. TREATMENT OF THE COMPANY'S GAIN ON THE SALE OF THE CENTRALIA PLANT

The Proforma Centralia Sale adjustment shown in the contested adjustments above shows zero for two reasons. First, since Staff is proposing that ratepayers be held harmless on the replacement power issue as discussed under the topic of power supply, the plant and related expenses are left in the per books results of operations. Second, Staff's recommended method to pass the gain on the sale of Centralia back to ratepayers is through the use of a billing credit at rates equivalent to the Company's DSM tariff rider in electric Schedule 91 (Ex. T-601, page 1, lines 19-20 and TR page 1567, lines 4-7). As stated at TR page 1567, lines 4-7, this proposed method does not affect general rates; it establishes a billing credit equal to the rates in the DSM tariff rider. This proposal passes back to customers approximately $3.5 million per year (Schedule 91 rates multiplied by volumes in Ex. 493, page 1 of 6).

The total amount of after tax gain from the Centralia sale assigned to Washington is $19,869,296 (Ex. 448, page 1, line 5). Staff's recommended billing credit methodology would credit customers an amount equal to about $3.5 million per year which would take approximately 15 years to return the grossed-up gain, plus a return on the unamortized balance, to customers.

The Company has proposed to first use the proceeds of the Centralia sale to offset the costs of the 1996 Ice Storm, and then to use an eight year amortization period (Ex. 448). Staff objects to the Company's proposal to use the gain on the Centralia sale to offset the 1996 Ice

Storm costs, but agrees with the use of an eight year amortization period. To quantify the amounts to be returned to customers, then, the calculation in Ex. 448 can be used. The calculation can be corrected by removing the 1996 Ice Storm costs by changing the figures on lines 4, 10, and 25 of Ex. 448 to zero. This produces a revenue requirement reduction of $6,575,763 (revising line 24) using an eight year amortization of the gain, including a return on the unamortized balance. Staff agrees with the Company's proposed shorter amortization period because it makes it more likely that the ratepayers who contributed towards the investment in Centralia will be the ratepayers who reap the benefits of the gain.

The eight year amortization period proposed by the Company is more in line with the amortization periods used by other parties to the sale of Centralia. The settlement in the recent PacifiCorp rate case included a five year amortization (Third Supplemental Order dated August 9, 2000, Docket No. UE-991832). PSE has not made a final determination on the length of time it will take to refund its' share of the gain. However, the length of time used by PSE and PacifiCorp should be taken into account when determining the period for Avista.

If the Commission concludes that the Company should recover the costs of replacement power for Centralia at this time, then the results of replacing the rate base and associated expenses with the replacement power contract is shown in Ex. 269, page 9 of 11, column PF11.

C. <u>EXECUTIVE COMPENSATION – CEO BASE SALARY ADJUSTMENT</u>

Avista paid its CEO, Mr. Matthews, an annual base salary of $750,000 under his employment agreement. Staff recommends that the Commission, for ratemaking purposes, adjust the base salary to $570,000. This represents a disallowance of $180,000. Avista challenges Staff's proposed adjustment as infringing upon the Company's right to determine how much to pay its executives, contending that this is an area of management discretion and prerogative (Ex. T-14, Rebuttal Testimony of Matthews, page 3, line 20, through page 4, line 2; Ex. T-393, Rebuttal Testimony of Mitchell, page 3). Avista's assertions, however, reflect a fundamental misunderstanding of the purpose underlying ratemaking adjustments. As the State Supreme Court noted in People's Org. for Wash. Energy Resources (POWER) v. Utilities and Transp. Comm'n, 104 Wn. 2d 798, 810-11, 711 P. 2d 319 (1985):

> The effect of disallowing an item of operating expense for ratemaking purposes does not relate to whether the utility had the right to incur it or not. Rather, the utility is not permitted to recover the expense in question in its rates to customers who purchase a regulated product or service. Thus, the shareholders of the utility must absorb the disallowed expenses, with a resulting reduction in the actual rate of return earned by them.

Staff does not contest the right of Avista's management and shareholders to set their CEO's base salary at whatever level they choose. However, ratepayers should not be required to fund the entire amount where the evidence clearly shows that Mr. Matthews' base salary is markedly higher than the base salaries given to CEO's of similarly situated companies, both nationally and regionally, as is the case here.

1. National Comparison of CEO Base Salaries

Staff's adjustment is based in part on a comprehensive CEO salary comparison using the companies listed in Ex. 572, page 2. Ms. Huang's exhibit contains two classes of companies. In terms of assets, number of employees, and market capitalization, Avista compares closely to those companies having revenues of $1 - 3 billion. In order to compare companies from a revenue perspective, Ms. Huang increased the sample population to include a second class, consisting of companies having annual revenues of $3 - $4.2 billion. Avista, with revenues of $3.6 billion, falls in the middle of this class.

Staff combined the two classes of companies as a pool to determine their CEO base salaries in 1998. The median CEO salary, as shown in Ms. Huang's exhibit, was $545,000 for a company the size of Avista in terms of assets, number of employees, market capitalization, and total revenues. Staff's proposed adjusted base salary of $570,000 for Mr. Matthews is thus even higher than the national median level for similarly situated companies.

Avista's analysis of executive officer salaries relied on the class of companies in the Towers Perrin study having revenues of $3 - $6 billion (Ex. C-401). The Company's reliance on this study is erroneous for two reasons. First, Towers Perrin reviewed, but then elected to completely ignore, the factors of assets, number of employees, and market capitalization where Avista compares most closely with $1 - $3 billion companies (Id., page 7). Second, the Towers Perrin study showed that Mr. Matthews' compensation level was set within the 50th to 75th percentile of $3 - $6 billion companies, even though Avista falls in the low end of this class, and then only from a revenue perspective. In fact, companies within the $3 - $6 billion range have from two to five times as many assets, number of employees, market capitalization, and revenues as Avista. Comparing Avista with larger companies with higher assets, employees, market capitalization, and revenues results in a higher level of compensation for Avista's CEO.

This situation thus reflects the philosophy of Avista's Compensation & Organization Committee, as set forth in the 1998 proxy statement: "The Committee considers but does not target executive officer compensation at the median of similarly situated executives at the Company's competitors." (Ex. 374, page 11). Avista management is free to pursue this philosophy, of course, but its shareholders and not the captive ratepayers should bear the additional expense.

2. Regional and Internal Comparison of CEO Base Salaries

Staff also compared Avista to other utilities providing electric and natural gas service in Washington. In terms of total retail utility revenues, retail electric and gas customers, total utility assets, and number of employees Avista is between two and five times smaller than Puget Sound Energy and PacifiCorp on a system basis (TR 2177). Yet Mr. Matthews' base salary greatly exceeds that of PSE's CEO, who was paid $532,971 in 1998 (Id.). And Mr. Matthews's base salary roughly equals that of PacifiCorp's CEO, Mr. McKennon, who was paid an annual base salary of $780,000 under his employment agreement, but who, unlike Mr. Matthews, received no signing bonus or restricted stocks (TR 2177-78).

Mr. Matthews' salary also substantially exceeds the total compensation paid to his predecessor as CEO, Paul Redmond, by over 32%, counting base salary alone, without signing bonuses and restricted stocks (TR 2181). After 34 years with Avista (13 years as CEO), Mr. Redmond's salary increased in March 1998, three months prior to his retirement, to a level approximately equal to Staff's recommended level (Ex. C-391). This is the level Staff recommends the Commission adopt for ratemaking purposes; it is the appropriate amount to allocate to ratepayers.

D. SIGNING BONUSES AND RESTRICTED STOCKS

Avista provided both signing bonuses and restricted stocks to three of its executive officers during the 1998 test year. The Company states that these are paid as part of a "total compensation package" to attract and retain qualified individuals (Ex. T-535, Rebuttal Testimony of Feltes, page 3). The Company also claimed that restricted stocks (stock-based signing bonuses) provide the new executive with an immediate interest in the Company, closely aligning the executive's financial well-being with the Company (Ex. 386).

Avista, however, has failed to show that these items are recurring, ongoing business expenses. Moreover, Avista has failed to show that ratepayers have benefitted from these generous offerings to its executives. Staff, accordingly, recommends that the Commission disallow both the signing bonuses and restricted stocks for ratemaking purposes.

> The Company's own 1998 proxy statement declares, "To our shareholders": The primary objective in establishing compensation opportunities for executive officers is to support the Company's goal of <u>maximizing the value of shareholders' interests.</u> To achieve this objective, the [Compensation and Organization]Committee believes it is critical to:
>
> - Hire, develop, reward, and retain the most competent executives possible <u>by providing compensation opportunities which are competitive in the marketplace</u> . . . .

(Ex. 374, page 10.) (Emphasis added.) <u>Accord</u>, <u>id.</u>, page 12 (long-term incentive plan, including stock options, are primarily designed to link management compensation with long-term interests of shareholders). Avista further confirms that it pays signing bonuses and restricted stocks to its executives as part of their compensation package to make up for bonuses lost from their former employers (Ex. 384; TR 165). None of these goals or objectives have been shown to benefit ratepayers.

Moreover, Avista has devoted significant time and resources to non-regulated activities since Mr. Matthews joined the Company. While Avista had only one non-regulated subsidiary (Pentzer) in 1995, it now has 13 (Ex. 573). In 1999, revenue from non-regulated operations comprised 86% of total corporate revenue (Ex. 400, page 3) (1999 Form 10K). Staff agrees that

Avista is "a company that is clearly repositioning itself," in this regard (Ex. T-393, page 3). Seventy-one percent of the Company's operating revenues in 1998 came from the non-regulated portion of the business (Ex. 5, page 25) (1998 Form 10-K). Avista looked to Mr. Matthews' experience with companies having large non-regulated operations in deciding to hire him as CEO (Ex. 399, page 1, last ¶) (citing his extensive history with other energy companies including Texaco, Tenneco, and Exxon).

Ms. Feltes stated that executive compensation is based on the concept that "top talent creates greater efficiency and productivity ultimately providing the best service to our customers." But Avista's performance on the regulated side has not been stellar in recent times. Despite significant signing bonuses and restricted stocks, management today appears no better than in the past. Avista's 10K reports show that its regulated operating income has steadily decreased from 1997-1999. Cost per customer increased from \$1.32 in 1997 to \$1.61 in 1998 and \$1.65 in 1999. Earnings per share have dropped precipitously, from \$1.96 in 1997 to \$.12 in 1999. And Avista's recent conference call to Wall Street analysts reported a loss of \$90 million in gross margin for Avista Utilities during the second quarter of 2000, despite a projected <u>gain</u> of \$70 million in gross margin for unregulated Avista Energy, and additional potential losses of \$50 million on the regulated side by the end of 2000 (Ex. 17, pages 4, 9). As Mr. Matthews frankly acknowledged, "And to be as candid as I can with you, we just plain blew it in the utility. That's my ultimate responsibility." (Ex. 17, page 4). Again, Avista has made no showing that either signing bonuses or restricted stocks were designed to benefit, or have in any way benefitted, the ratepayers.

Avista contends that 30 of the 40 companies in Staff's data set (Ex. 572) use stock awards as a compensation tool and eight out of the 40 use either signing bonuses or relocation allowances (Ex. T-393, page 4). However, the relevant question is whether the cost of these awards should be borne by the ratepayers or the shareholders. Avista has made no showing that any other state commissions have embedded signing bonuses or restricted stocks in rates. Nor is Avista aware of any cases in which this Commission has done so (TR 2179-80).

To the contrary, this Commission has previously held that stock option plans are to be borne by the shareholders. In the Matter of an Application of Northwest Natural Gas Co. for an Order Authorizing It to Issue and Sell Up to 300,000 Shares of Its Common Stock Pursuant to Its 1985 Option Plan, 1987 Wash. UTC LEXIS 84 (Cause No. FR-86-142, June 17, 1987). In that docket, Northwest implemented a stock option plan whose stated purpose was "to enable Northwest to attract and retain experienced and able employees and to provide additional incentive to these key employees to exert their best efforts for the company." (Id., page 1). The Commission held that, while it would approve the plan, it would also require that "in general rate proceedings, adjustments will be made as appropriate to ensure that the costs of the stock option plan will be borne by shareholders rather than by ratepayers." (Id., page 6). The Commission should continue to adhere to this policy. See also Re Southwestern Bell Telephone Co., 137 PUR 4th 63, 89-90 (Okla. Corp. Comm'n 1992), in which the Oklahoma Corporation Commission disallowed a signing bonus because it was paid in addition to wages and represented greater compensation than market level.

E. PROFORMA INCREASE TO OFFICERS' SALARIES

Avista has provided proforma officer salary increases ranging from 11% to 49%, as indicated at page four of Ms. Huang's Ex. 571. Staff believes these increases are wholly unjustified and should be reduced to 3.2%. First, they are inconsistent with the increases the Company actually paid its executive officers. In 1997, Avista's Compensation & Benefits Committee granted all executive officers a 4% base salary increase (Ex. 398, page 7) (1997 proxy statement). In 1998, the Committee granted executive officers base salary increases ranging from 3% to 11% (Ex. 374, page 11) (1998 proxy statement). In 1999, the Committee granted executive officers base salary increases ranging from 0% to 8% (Ex. 397, page 11) (1999 proxy statement).

Second, Avista proposes a 2.14% wage increase for non-officers and 3% for union employees. Staff's proposal to use 3.2% for pro forma officer salary increases is greater than either of these amounts. It also equals the overall United States wage and benefits increase, as quoted in the April 6, 2000, Wall Street Journal article entitled "Executive Pay." (Ex. T-570, page 8, lines 12-14).

Finally, (as noted above in the discussion of signing bonuses and restricted stocks), Avista's proposed pro forma increases of 11% to 49% are entirely unjustified when measured against Avista management's recent performance. Staff's recommendation is far more representative of ongoing conditions than Avista's proposed pro forma officer salary increases, and should be adopted.

F. ALLOCATION OF OFFICERS' SALARIES BETWEEN REGULATED AND NON-REGULATED OPERATIONS

Staff used the three-year average of revenues, number of employees, and non-officers wages between regulated and non-regulated operations for 1997, 1998, and 1999 to determine an appropriate allocation factor. The average of these three factors provides an allocation of 52% to regulated activities and 48% to non-regulated activities. Ex. 574 details these calculations. Staff employed a similar methodology in WUTC v. Washington Natural Gas Co., Fourth Supplemental Order, (Docket UG-920840) (September 27, 1993) and the Commission accepted Staff's adjustment. This methodology is based on quantifiable business parameters, is reasonable and appropriate, and should be adopted here.

The gross revenue amounts (rather than net revenues) which Staff used are consistent with the revenues used in the Company's Tower Perrin study. The number of employees Staff used for regulated and non-regulated operations are consistent with the information Avista submitted to the SEC in its 1997-1999 10K forms (Exs. 5, 400, and 415 (1st page, 2nd ¶)). Avista's suggestion to ignore those numbers and substitute far smaller figures for non-regulated employees in Staff's calculation should be rejected.[1]

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[1]The Company suggests that the Commission use lower revenues (net revenues rather than gross revenues) and lower employee numbers than those recommended by Staff. If the Commission were to do so, however, many issues within the Company's case would have to be reevaluated. For example, the Company's proposal to remove Energy Trading expenses from its non-regulated gross revenue would place Avista at the very low end of the $1 - 3 billion class of companies. Likewise, the Company's proposal to use 1,333 employees for its regulated operations and 140 employees for its non-regulated operations for 1998 (contrary to the Form 10K figures) would result in Avista's falling outside of the $1 - 3 billion class altogether.

In this event, Mr. Matthews' and other officers' compensation, and the Company's Towers Perrin compensation study, would have to be reevaluated. Otherwise, Avista would simply able to pick and choose the level of revenues or numbers of employees that benefit it the most.

Moreover, the Commission should categorically reject Avista's proposed "method" of determining allocations of officers salaries, as it is not a method at all. Both Ms. Feltes and counsel for Avista derided Staff's methodology, which uses actual documented data, as a "formulaic" or "formula based" approach (Ex. T-535, page 7; TR 1434). But Avista would have the Commission discard actual data and rely on no documentation whatsoever. Rather, as Mr. Matthews proposed, when asked to describe Avista's allocation process:

> [I]t's generally a subjective process, based on a person's thoughts and feelings on where they're spending the majority part of their time. You know, what percentage of my time am I spending on this versus this. It's not a time sheet-driven aspect; it's more a subjective call on where their emphasis are during the year.

(TR 111.) Ms. Mitchell agreed with this description of the process, and added that there are no work papers that calculate the time spent. Though she referred to a "study" that was done:

> This study is the officers and their executive assistants sit down and talk about where they've been and where they are going to go. In that respect, a qualitative study is performed.

(TR 641-642.) There is no documentation to account for time spent on specific activities, or even for time spent at a particular subsidiary.

Staff submits that if the Company wishes to have the ratepayers pay for a significant portion of officers' salaries, when it is undisputed that large amounts of the overall time was spent working for unregulated subsidiaries, it must rely on more than subjective recollections. The Company's approach is a recipe for unprincipled, arbitrary salary allocation. After all, how could one verify another's "thoughts and feelings," other than to accept them at face value, if no more evidence were required?

Avista's allocations also appear inconsistent with much of the evidence. For example, Avista's organizational chart (Ex. 573) shows that Mr. Turner is also President of Avista Services, Inc., a non-regulated operation. Yet the Company allocated 100% of his salary to regulated operations. And Mr. Matthews continued the 60-40% allocation of his predecessor, Mr. Redmond, even though he absorbed additional non-regulated responsibilities after Mr. Redmond left in June 1998 (TR 115; Ex. T-570, pages 9-10). Finally, as noted previously, Avista rapidly expanded its non-regulated operations from 1995-1999, while regulated operations remained steady. While Avista had only one non-regulated entity in 1995, by 1999 it had 13. And by 1999, 86% of Avista's total corporate revenue came from non-regulated operations (Ex. 573; Ex. T-570, page 10).

For these reasons, the Commission should reject Avista's undocumented salary allocation and accept Staff's recommended allocation of 52% to regulated operations and 48% to non-regulated operations.

G. TEAM INCENTIVE BONUSES

Staff recommends that the Commission disallow, for ratemaking purposes, Avista's team incentive bonuses which totaled $4,407,796 in 1998.[2] These bonuses have fluctuated wildly in recent years, making the 1998 payout anything but representative. Moreover, the evidence shows, despite Avista's claims to the contrary, that these bonuses are not tied to goals benefitting ratepayers. The Commission made clear in the US West rate case, Wash. Util. and Transp.

[2]Avista also paid out certain "Pacesetter" awards to individuals to recognize excellent performance. These bonuses have remained relatively constant over the years and they appear to be expenditures properly charged to ratepayers. Staff recognized and allowed Pacesetter awards as normal operating expenses.

Comm'n v. US West Communications, Inc., Docket No. UT-950200, 169 PUR 4th 417, 452-453 (April 11, 1996), aff'd, 134 Wn. 2d 74, 949 P. 2d 1337 (1997), that team incentive plans not tied to goals clearly benefitting ratepayers would face disallowance in future proceedings.

Team incentive bonuses are paid out to Avista employees at management's discretion. For 1998, the Company's team incentive goals were to add value to the line of business and corporation, and provide for the fundamental building of corporate value and savings, i.e., "sustained earnings." (Ex. T-570, page 14.) In 1999, team incentive bonuses were even more clearly aligned with corporate earnings per share (Id.). As Ms. Feltes explained:

> And what we do is we start at a top level with how we're going to fund our incentive plan. So we will look at the top level as being corporate goals, for instance, earnings per share or net income. . . . And, of course, the incentive pool is not funded if we don't meet the top level corporate goals that are stated.

(TR 2208-09.) Avista's corporate earnings were $0.12 per share in 1999, significantly below the Company's targeted level. As a result, no team incentives were paid in 1999. Based on Avista's June 21, 2000 recitation of its corporate performance to date this year to Wall Street investors (in which it cited a loss of $90 million in gross margin on the regulated side with the possibility of another $50 million loss by the end of the year), and its tie-in of team incentives to corporate goals, it stands to reason that no team incentives will likely be paid in 2000, either.

Ms. Mitchell indicated that she believed the 1998 level of team incentives represents a "reasonable level of total bonus compensation for test period purposes to reflect the situation going forward."[3] (TR 648.) Clearly, it is not representative at all:

- In 1995, team incentive bonuses totaled $1,575,516.
- In 1996, they increased 20% to $1,895,544.
- In 1997, they decreased 45% to $1,039,373.
- In 1998, they quadrupled to $4,407,796.
- In 1999, they went down to zero.

Avista rather feebly attempts to show that the team incentives are tied to customer-oriented goals. Ms. Mitchell refers to only three of Avista's teams: (1) Energy Delivery/Transmission Team; (2) Energy and Market Services; and (3) Administrative, and then paraphrases their team incentive goals. (See Ex. T-393, page 10.) But only part of the first team she lists (Energy Delivery) has a "customer satisfaction" goal that might directly benefit customers or ratepayers. And even in the case of Energy Delivery, net operating income and not customer satisfaction is the primary driver of the gainsharing plan (Ex. C-402, page 14) (two-thirds of the possible award is based on NOI). The goals for several other Avista teams are clearly corporate-oriented. (See e.g., Ex. C-402, page 70, 93-94). Finally, the illusory nature of the connection to customer-oriented goals for all areas is made clear when a drop in corporate performance effectively nullifies all team awards, regardless of how well or poorly customers are served. Ms. Huang correctly observes that shareholders, not captive ratepayers, should bear the cost of these awards (Ex. T-570, pages 14-15).

[3]Ms. Mitchell also stated that the $4.4 million figure for 1998 reflected the Company's desire to "rethink compensation strategy[.]" Nevertheless, she claimed that Avista "continues to place increased emphasis on incentive compensation as a useful tool to drive results and direct employee focus." (T-393, page11). Yet with regard to team incentive awards, the evidence from 1999 alone shows that this is simply not the case, at least not when corporate earnings are not at the desired level.

As noted earlier, the Commission recently addressed this precise issue in the US West rate case in connection with that company's "team and merit awards:"

> *Plans which do not tie payments to goals that clearly and directly benefit ratepayers will face disallowance in future proceedings.*

WUTC v. US West, 169 PUR 4th at 453. (Italics in original.) The Commission further explained:

> [T]here is a potential tension between service quality and earnings. A firm can concentrate on financial elements so heavily that it can lose sight of the importance of providing customer service. . . Financial goals are at best a crude way to measure specific efficiencies that employees can accomplish. (Id.)

Avista's team incentive awards are virtually identical to the bonus plan in WUTC v. Puget Sound Power & Light, Docket No. UE-920433, et. al, 11th Supp. Order (September 21, 1993), page 61. The Commission disallowed those bonuses whose primary focus was on earnings per share and where the bonuses were funded if earnings achieved a specific level. Avista's team incentive awards should likewise be disallowed for ratemaking purposes.

H. RELOCATION EXPENSES

Avista's 1998 relocation expense is $468,000, more than four times the 1999 level of $110,000, and nearly four times the 1997 level of $123,540. (The data for 1993 through 1996 is not available, according to Avista.) The 1997 and 1999 relocation expenses account for 67% of the available information. Staff has averaged these two years to arrive at $116,000, which Staff believes is a much more representative level than the test year figure.[4]

I. INJURIES AND DAMAGES

1. 1991 Firestorm Litigation Expenses

Avista proposes to recover in rates the litigation expenses relating to a firestorm that occurred in 1991. Avista argues that approximately one-sixth of these expenses, approximately $230,000, should be brought into the test year. (See Exs. 232, 233; Ex. T-595, Direct Testimony of Schooley, pages 4, 5). This would be in addition to the $2.6 million in system-wide litigation fees actually incurred during the test year, a figure that already exceeds (and in several instances overwhelms) the legal expenses incurred in any other year from 1989 to 1999 (Ex. 277; TR 1538). It would also be in addition to one-sixth of the net settlement payment for the 1991 firestorm. Staff recommends that these prior period expenses, not representative of ongoing costs, be excluded from the test year.

The purpose of ratemaking is to set rates based on representative levels of expenses. Staff does not contest the settlement paid to claimants for damages in the 1991 firestorm (TR 1490). Staff includes this settlement payment in the six-year average used for damages paid to third parties (Ex. 596). But Staff does contest the inclusion of litigation expenses in addition to the legal expenses already in the test year. Legal expenses must be considered an ongoing

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[4]Staff would agree to include officers' relocation expenses in the test period to correct the inadvertent omission of these expenses in its calculation. However, since the Company did not assign any officer relocation expenses to its non-regulated subsidiaries, the calculation in Ex. 581 is incorrect. After properly allocating 48% to the subsidiaries, the impact on the total amount of relocation expenses would be an increase of $11,000 for Washington electric and $3,000 for Washington gas.

normal expense of corporate activities which is recoverable, but which is not attributable to any specific cause. While litigation may well have been necessary to settle the firestorm, this litigation was simply the legal event of the time, so to speak, when it occurred. It should not be added piecemeal to the test year expenses.

Contrary to the suggestion of counsel for Avista, this will not create any "perverse incentives." As Mr. Schooley noted, the Company when faced with litigation presumably will act in a prudent manner that arrives at the best resolution possible (TR 1494-95). Moreover, Avista's argument runs contrary to the fundamental nature of ratemaking. Mr. Schooley explained it well:

> Q: If a company knows that in a major piece of litigation that it will not recover its litigation costs, is that a factor that a company might take into account in terms of the timing or the level of settlement ultimately reached given the litigation costs involved?
>
> A: No, I don't think so. Because ratemaking is not a process of determining a particular expense that will be recovered or not. It's a question of establishing the total expenses of the company in relationship to the revenues, those total expenses including a fair rate of return on the rate base to the investors in that rate base. So no particular expense is used in the ratemaking process. So the question of whether these litigation expenses should or should not be recovered is a moot point.

(TR 1494.) The $2.6 million level of litigation expense included in the test year is sufficient for normal ongoing litigation. TR 2141 (Falkner). It is the only amount needed for ratemaking purposes.

2. 1996 Ice Storm Expenses

Avista proposes to recover in rates the expenses pertaining to another out-of-period event, the 1996 Ice Storm. Avista does so despite the fact that this is clearly an abnormal, non-recurring event, despite the fact that Avista made it clear to both customers and the financial community that it would <u>not</u> seek to recover ice storm costs from the ratepayers, despite the fact that Avista never filed an accounting petition to capitalize this expense for future recovery, and despite the fact that Avista's proposal flatly contradicts the principle of normalized expense recovery for ratemaking. Staff recommends that the 1996 Ice Storm expenses be excluded from the calculation of the Company's revenue requirement.

The 1996 Ice Storm was truly extraordinary. So much so that, according to a Company-published report, the National Weather Service categorized this ice storm as the only event of its kind in 115 years of record (Ex. T-595, page 5). Avista now proposes to build one-sixth of the 1996 Ice Storm (over $2 million) into rates. What did Avista tell its customers at the time? In a news release on December 5, 1996, Washington Water Power's CEO, Paul Redmond, declared:

> [O]ur decision is to write-off the cost of this storm against our 1996 fourth-quarter earnings. In preserving our ten-year record of energy price stability, <u>our customers will see no change in electric prices as a result of the storm damage costs.</u>

(Ex. 234.) (Emphasis added.) Avista made this clear as well to the financial community. In the Company's 1996 Form 10K filed with the Securities and Exchange Commission, Avista stated that "No increase in rates will incur as a result of these costs." (Ex. 235.) Staff interprets these representations to mean what they say; there is no other reasonable way to interpret them.

Avista did not, at any time, file an accounting petition with the Commission to ask for these expenses to be capitalized for later recovery. This process, well known to the Company, is set forth in the FASB 71 and other Commission orders (TR 1530). The Company did not elect this course because, as it clearly indicated to all, it had no intention of attempting to recover these costs from ratepayers.

What the Company now proposes is simply retroactive ratemaking. Avista proposes to take one abnormal event from two years prior to the test year and build one-sixth of the expense into rates. On what principle? Where would the process logically end? If Avista at this point (having not petitioned for any regulatory asset) were allowed to include these truly extraordinary, non-recurring 1996 costs, there would then be no basis to treat extraordinary costs five or ten years prior to the test year any differently. This contradicts the fundamental premises of ratemaking.

Ratemaking is generally based upon the climate of a given area. This is the principle behind normalized power deliveries and normalized water years. It is also the principle behind basing storm damages on the expected or normal level of storms in the local area. The Company is at risk for the weather in a given year. If Avista incurred sufficiently volatile damages from storms, it would propose a smoothing mechanism to "normalize" this expense. It does not incur that volatility (Ex. 278; TR 2143). It does not propose a six-year average for overall storm damages.

Rather, Avista now proposes, after informing customers and investors otherwise, to include in rates on an ongoing basis, $2 million in costs arising out of an extraordinary, one-of-a-kind event occurring two years prior to the test year. The Commission should reject Avista's proposal.

J. HYDRO RELICENSING

Staff accepts Mr. Anderson's recalculation of the cost to administer the Clark Fork hydro licenses. His rebuttal testimony provides the necessary detail to justify the expenses. The hydro relicensing expense of $2,173,000 (Ex. 352) is a reasonable level for the near-term future.

Staff, however, continues to reject the balancing account Avista has proposed for variations in the hydro relicense expenses. The Company asserts the need for a balancing account by claiming the expenses vary significantly from year to year. However, the data does not show this to be true as reflected in Mr. Schooley's Ex. 597. Avista provides no rebuttal to this exhibit.

K. NEZ PERCE SETTLEMENT

Staff does not generally contest the inclusion of the Nez Perce settlement in current Washington rates. Staff recommends, however, that the Commission assign a portion of the Nez Perce settlement payments to Idaho operations. The settlement agreement (Ex. 239, page 3) clearly states that it includes settlement payments for distribution rights of way and for tribal taxes (TR 469-70). Both of these items are solely the responsibility of Idaho customers. Staff has calculated a reasonable level for this assignment of a portion of the overall settlement payments (Ex. T-595, page 12-13; Ex. 598).

L. MISCELLANEOUS ADJUSTMENTS

1. Name Change Expenses

Avista proposes amortizing over five years $1,123,000 in system-wide expenses the Company incurred in 1998 in changing its name from "Washington Water Power" to "Avista."

The Commission should reject this proposal. Staff recommends eliminating all name change expenses from the results of operations, reducing test year operating expenses by $529,000 in electricity and $133,000 in gas (Ex. T-595, page 14).

Staff's objection to inclusion of these expenses in rates is twofold. First, this is a one-time, non-recurring item. It is not representative of current or future utility costs (Id.) Second, the Company has failed to show consumer benefits arising out of this name change. Avista alleges that prior to the name change "consumers saw three basic organizational names, creating "customer confusion." In response to Staff's data request asking for instances in which consumers expressed confusion because Washington Water Power operated subsidiaries with different names, Avista stated it had no documentation of any such instances (Ex. 336). Avista could point to only one instance in which it was incorrectly listed in a magazine article (Ex. 337).

In fact, the change to "Avista" creates as much confusion as it allegedly resolves. Several other companies use the name "Avista." There is an Avista Incorporated in Wisconsin, an Avista Hotels in Florida (bought out in 1999), an Avista firm in the United Kingdom, an Avista Society studying technology in the Middle Ages. The Company's assertions of Washington ratepayer benefits from this name change have not been substantiated and should be rejected.

2. Y2K Expenses

Avista proposes amortizing over five years $1,651,000 in system-wide Y2K expenses the Company incurred in 1998. Staff recommends that the Commission reject this proposal. Staff's recommendation reduces test year expense by $777,000 in electricity and $197,000 in gas.

These expenses are non-recurring costs that should be removed to arrive at representative ongoing costs of operations. The Company asserts that the Y2K projects created "new value" by assuring that the systems will perform properly, rather than failing. The Company has a continuing obligation to assure that its systems remain in proper functioning order. The Company is incorrect, however, that extraordinary expenses of this nature should be embedded into rates.

M. STAFF RESTATING ADJUSTMENTS

In Ex. 274 Avista accepts some of Staff's proposed restating adjustments. The remaining points of contention include: political advertising by organizations to which the Company belongs; allocation of the costs of the CEO search; and the Paul Redmond tribute film.

1. Political Advertising

WAC 480-090-032 and 480-100-032 expressly forbid including political advertising or lobbying expenses in rates. They state that:

> [E]very public service company incurring any direct or indirect expense associated with or in furtherance of any political information or political education activity, shall account for such costs separately in a nonoperating expense account. No such expense shall be permitted for ratemaking purposes.

The Commission has consistently forbidden inclusion of political advertising and lobbying expenses in rates. See WUTC v. Puget Sound Power & Light, Docket Nos. UE-920433, et. al, Eleventh Supp. Order, page 69; Docket Nos. UE-931405, et. al, Fourth Supp. Order, page 3.

Ex. 29 shows a table of corporate memberships. The Company's representations of these organizations neglects to mention the lobbying activities of most of these groups, even though several exist largely for this purpose (Ex. T-595, page 17). Moreover, Avista has not presented sufficient evidence to determine the specific degree of lobbying by these groups (Mr. Falkner refers to two in his rebuttal testimony). Staff's adjustment excluding the corporate membership dues paid to these groups is reasonable and should be adopted.

2. Allocation of Costs of New CEO Search

Avista proposes that all of the costs of the search for a new CEO be borne by the ratepayers and none by the unregulated subsidiaries. This is clearly unreasonable. The Company's argument that Avista would have been searching for a CEO regardless of whether it had unregulated operations has no merit. Avista's CEO is responsible for the entire corporate operation, including its vast array of unregulated subsidiaries. The costs to find a new CEO should be equitably allocated between the ratepayers and shareholders. Staff recommends an allocation of 48% of the cost to its subsidiaries, consistent with Ms. Huang's allocation factor (Ex. T-595, page 19).

3. Paul Redmond Tribute Film

Staff recommends that the expenses associated with the film entitled "Tribute to Paul Redmond," be excluded from test year expenses. These expenses are not related to utility operations, provide no benefits to consumers, and are non-recurring. Ratepayers should not be required to fund this item.

N. RESTATE EXCISE TAXES/FRANCHISE FEES

The Company and Staff agree with the Excise Tax portion of this adjustment for both gas and electric expenses. However, Staff contests the treatment of the Franchise Fee portion of this adjustment. Staff disagrees with the Company on two key points.

First, RCW 35.21.860 is clear that cities and towns can impose franchise fees to recover only those actual administrative expenses incurred by a city or town that are directly related to receiving and approving a permit, license, and franchise, to inspecting plans and construction, or to preparation of a detailed statement pursuant to Chapter 43.21C RCW (Ex. T-608, page 11, lines 5- 8). The Company has produced no evidence to demonstrate that the fees paid to the towns of Millwood and Colville, and the City of Spokane, are for the actual costs incurred by those entities for activities recited in RCW 32.21.860 (TR page 1572, lines 13-17, and TR page 2140, lines 4-19). The Company relies on subsection 2 of RCW 35.21.860 which states that franchise fees in place by contract prior to April 20, 1982, will be allowed for the duration of the contract (Ex. T-268, page 10, lines 11-15). However, subsection 2 of RCW 35.21.860 conditions the grandfathering of the contacts by restricting the fees to the actual costs identified in subsection 1; if the fees exceed the actual costs allowed under subsection (1), then they are to be considered as taxes. When the Company asked if Staff has made any similar adjustmentsin the past, Staff witness Mr. Parvinen noted a recent Northwest Natural Gas case in Docket No. UG-970932 (TR page 1555, lines 14-18). The Company also relies on the Commission order (Ex. 271) as establishing the precedent for the current treatment of franchise fees (Ex. T-268, page 10, line 16, through page 11, line 3). As Mr. Parvinen stated, (TR page 1573, line 21, through page 1574, line 14) the Commission order (dated May 13, 1980) allowed franchise fees up to 3% as a representation of reasonable costs. RCW 35.21.860 (dated April 20, 1982) supersedes the Commission order and allows those grandfathered contracts only as long as it can be demonstrated that they are for actual costs.

Second, and perhaps more importantly, is the fact that many other cities and towns are already paying municipal taxes at the maximum rate of 6% (Ex. 275 and 276). By allowing the cities of Colville (electric), Millwood (electric and gas), and Spokane (gas) to spread the franchise fees to all general customers, many customers are paying beyond 6% and the customers within the cities of Colville, Millwood, and Spokane pay less than 6% (TR page 2139, line 11, through page 2140, line 3). The Company should be directed to treat these franchise fees as taxes for purpose of recovery of these expenses, and impose the costs of these franchise fees only on the residents of the municipalities that impose those fees.

III. THE COMMISSION SHOULD NOT APPROVE AVISTA'S REQUEST FOR A POWER COST ADJUSTMENT MECHANISM AT THIS TIME

The Company has proposed a power cost adjustment (PCA) that would allow it to recover from customers the difference between normalized power supply expense levels set in this case and the cost of power based on monthly changes in hydro-generation and market prices. Staff opposes this request both as originally presented by the Company and the revised proposal submitted by the Company with its rebuttal testimony.

A. THE WUTC HAS PREVIOUSLY SET OUT CRITERIA FOR EVALUATION OF A PROPOSED PCA MECHANISM

In its First Supplemental Order Denying Petition in Docket No. U-88-2363-P (September 19, 1989), this Commission rejected the request of Washington Water Power (WWP, now Avista) for an accounting order permitting implementation of a PCA mechanism. The Commission found that the Company's proposal did not satisfy the Commission's policy goals.

In that Order, the Commission reaffirmed the three broad policies relating to PCA mechanisms that it had established in its Sixth and Seventh Supplemental Orders in U-81-41, relating to Puget Power's Energy Cost Adjustment Clause.

First, ratepayers should receive the benefits of a cost-of-capital reduction if the Commission approves a PCA for a company. The Commission stressed that the Company must demonstrate the downward adjustment to the cost of capital, or the reason for the PCA would be seriously questioned.

Second, the Commission made it clear (First Supp. Order, U-88-2363-P, page 8) that a PCA clause should be linked to those factors that are weather-related.

Third, the Commission found that a PCA clause should be a short-run accounting procedure that reflects the short-run cost changes affected by unusual weather, and that the cost of new long-term resources acquired to meet new load should be excluded from the mechanism.

1. A PCA Shifts Risks of Higher Power Costs from the Company to the Ratepayers

On cross examination on July 14, 2000, Company witness Brian Johnson made great efforts to avoid acknowledging that a PCA shifts some risks from the Company and its shareholders onto the ratepayers. However, that fact is unavoidable, regardless of the semantic gymnastics employed: If the actual increases in costs of power purchased by the Company, or the increase in the market index price of power, are passed on to the customers, then the risks of paying higher costs for power are reduced for the Company. As the Commission stated in its First Supp. Order, Docket No. U-88-2363-P, page 10:

> Any PCA clause involves a regulatory tradeoff between the goals of rate stability and earnings stability. Earnings stability benefits a company and its stockholders, while ratepayers seek stable rates. If, through the establishment of a PCA, a company receives the advantage of earnings stability, some of that benefit must be passed on to ratepayers to compensate them for enduring rate instability.
>
> . . .
>
> The Commission reiterates the requirement that a downward cost of capital adjustment must be demonstrated.

B. THE COMPANY'S PROPOSED PCA DOES NOT MEET THE COMMISSION'S CONDITIONS FOR APPROVAL OF A PCA

In the WWP 1989 case, the Commission made it clear that the company must provide the Commission with a specific proposal on how ratepayers would achieve a cost-of-capital benefit. However, neither the Company's original nor its revised PCA proposals address the first and most fundamental condition set forth by the Commission. In Avista's original proposal there is not one word about an explicit cost of capital reduction from implementing a PCA. On rebuttal, Mr. Johnson identifies that issue raised by Staff and states that Dr. Avera's testimony will address the issue (Ex. 426, page 2, lines 5-7). The only testimony that Dr. Avera presented relating to the impact of a PCA on the rate of return is found in Ex. 101 (Avera direct), page 56, line 23, through page 57, line 15, and on pages 20 and 21 of Ex. T-135. He does not provide an explicit amount by which implementation of a PCA should reduce Avista's cost of capital in either portion of his testimony. In his rebuttal testimony, Dr. Avera only suggests that the amount recommended by Dr. Lurito in a 1992 Puget Sound Energy case would be a conservative adjustment for Avista; he does not state a specific amount, higher or lower, for such an adjustment for Avista. In Ex. 108, Avista's response to Staff Data Request No. 92, Staff had inquired about studies that Avista had done to quantify the increased investment risk to the

Company from lack of a PCA; the response simply refers to pages 56 and 57 of Dr. Avera's direct testimony. Based on this clear omission alone the Commission should not approve the Company's PCA proposal.

The second and third conditions for evaluating a PCA address the degree to which the power cost mechanism is linked to those factors that are weather-related. Staff believes the Company's original and revised proposals do not meet these conditions.

The original proposal included long-term PURPA contract changes and changes in some thermal generation as inputs to the PCA mechanism. Staff's direct testimony raised the issue of the propriety of including these elements, in addition to other concerns. In a piecemeal response to the testimony of Staff and Intervenors in its rebuttal testimony, the Company presented a revised PCA proposal removing the PURPA contracts and Rathdrum turbine generation. Staff agrees with the proposal to remove the PURPA contract price changes from any PCA mechanism. However, despite the concern expressed in its direct testimony about inclusion of certain thermal resources, Staff does not agree with the removal of Rathdrum generation from the PCA mechanism given the characteristics of the Company's revised PCA mechanism. Staff's recommendation in its direct testimony to remove Rathdrum generation was based on a possible PCA mechanism which was <u>only</u> hydro-generation related.[5]

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[5]A simple PCA would only compare actual hydro-generation level to normalized levels and then make a simple adjustment based on the difference. Under this simple mechanism there would be no adjustment related to changes in thermal generation. If a mechanism is adopted which tracks market prices, then those thermal (or other) resources that can be dispatched to sell into that market should be included.

On cross-examination, Mr. Buckley discussed the issue of what should be included in a PCA as follows:

> ”If you had a PCA that was solely related to changes in water conditions and was structured somehow that it did not incorporate market price changes or follow complete market price changes, then I think that the thermal resources should be out.
>
> If you had ended up with a PCA I believe such as the company proposed on its rebuttal case where you are recalculating where you are following the market and changes in market prices, then you would have to incorporate some of the thermal projects. And those would be such as the company described in its original filing, ones like Rathdrum, that basically sell into a market, so that when the market was high you would be getting the benefit of Rathdrum. In my testimony, I raised the issue, and the issue was more associated with a PCA that would be solely water, and therefore Rathdrum would be out in that instance.”

TR page 1325, line 24, through page 1326, line 15. In other words, if the PCA mechanism relates only to weather changes, the production of plants that produce electricity through thermal generation should not be considered. However, if the market price of power is an input into the mechanism, Staff believes that the generation of power through the Company’s thermal generation plants must be considered because those plants produce power that, if not needed by the Company to serve its customers, can be sold on the market at a profit. Those profits, if any, should be included in the calculation of power costs as they are additional revenues from power that are not captured in the calculation of power costs or setting rates.

As stated earlier, the Company's revised proposal not only tracks changes in hydro-generation but <u>also</u> tracks changes in market costs for energy, independent of whether there are any actual changes in hydro-generation. Under the Company's original and revised proposals, it is the dollar amount of sales or purchases which are compared to derive an adjusted amount.

This means that even if hydro-generation remains the same, any changes in prices (market index prices under the Company's proposal compared to the prices from the Simple Dispatch Model) are reflected in the PCA. (TR 2126, lines 8-23). Mr. Johnson claims in his rebuttal testimony (Ex. T-426, page 15) that the proposed PCA mechanism “would be limited to tracking changes in weather-related power supply expense due to variations in hydro-generation and short-term energy prices.” A careful review of the Company’s proposal reveals that this is not true. The proposed mechanism can, and will, result in adjustments even when water and/or weather is equal to normalized levels. This fact was also made apparent during questioning of Mr. Johnson on cross-examination (TR pages 2126, 2127).

Recent events appear to indicate that energy prices can no longer be correlated with weather or hydro conditions (Ex. 540, page 46). The statement on page 7 of Ex. 426, Mr. Johnson’s rebuttal testimony, lines 20-23, is no longer true. For example, even though the stream flow for the year 2000 has been as predicted, the Company has testified that the market price for short-term power purchases in May and June 2000 were at an unprecedented level. Therefore, if the market price is used as an indicator in the PCA, even when there are no weather-related reasons for a price change, the Company would be passing those costs on to the ratepayers.

Staff objects to the Company’s revised proposal because it goes well beyond the type of mechanism the Commission has said is appropriate, e.g., one that addresses weather-related events that cause changes in stream flow that are beyond the Company’s control.

C. STAFF HAS ADDITIONAL CONCERNS ABOUT THE COMPANY'S REVISED PCA MECHANISM

Even though the Company did address some of Staff's criticisms, its revised proposal remains unacceptable for additional reasons.

1. The Proposed PCA Mechanism Contains No Incentives for Least-cost Acquisition of Power

The Company is not proposing to include an incentive mechanism in the PCA, as it proposed in Docket No. 88-2363-P, where the Company proposed to flow through only 80% of the change in net power supply expenses to customers. This, in Staff's view, creates a greater risk that the Company will not seek the absolute lowest available price in purchasing power, as the Company will have shifted the risk to its customers. Staff is concerned that if a PCA mechanism is adopted that includes the ability of the Company to recover for changes in the market price of power, irrespective of water conditions, the Company does not have the proper incentive to minimize or control costs, particularly when making resource decisions between long-term purchased power opportunities which would not be tracked by the PCA mechanism and shorter-term purchases which would be tracked.

The Company, on rebuttal, attempted to address Staff's concerns regarding incentives to acquire least cost power. There does, however, remain a disconnect between the PCA mechanism and actual costs for energy that the Company may acquire to meet its needs. The Company proposes the use of a "market index" to price the sales or purchases that are determined to be necessary from the Simple Dispatch Model. Using a market index provides no assurance that the Company actually acquires that energy or pays that price. The Company says it will have the incentive (Ex. 426, page 11) because the adjustment will be based on the market index. Staff believes this mechanism may allow the Company to implement an adjustment based on a market index without any showing that it actually incurred those costs (priced at market or otherwise) to meet its requirements. Staff believes this is not the true intent of a proper PCA mechanism.

2. The Hourly Shape Adjustment in the Proposed PCA Is Difficult to Follow

Even with the proposed use of market index prices in the calculation in the Company's revised mechanism, the hydro-hourly shape adjustment portion of the mechanism is difficult to follow and requires some additional assumptions to be made that may or may not reflect reality. This adjustment, that attempts to account for the actual shape of hydro-generation, needs further review and input from customers.

Staff believes that the ease of administering and of auditing the PCA mechanism inputs and outputs should be issues brought to a collaborative effort with customer involvement. Staff believes that the significant change in the levels of risk the customers would experience warrant this recommendation.

D. STAFF RECOMMENDS A PUBLIC PROCESS, WITH CUSTOMER INVOLVEMENT, TO EXPLORE THE POSSIBILITIES OF A PCA MECHANISM IF THE COMMISSION WISHES TO CONSIDER ADOPTING SUCH A MECHANISM

Staff's recommendation regarding the Company's request for a PCA is in two parts. First, Staff recommends that the Commission not adopt either the Company's initial PCA mechanism or the revised mechanism presented on rebuttal for the reasons set forth in the discussion above. Second, Staff continues to recommend that the Commission, if it wants to consider a PCA mechanism in todays' environment, direct the Company to initiate a public process that involves customer input. Staff is willing to work with the Company in the most expedient way to carry out such a process. Recommendations regarding a PCA could be brought forward to the Commission at a later date as a result of the collaborative effort.

In its rebuttal testimony, the Company did not address this recommendation of Staff. In cross-examination, the Company attempted to obtain Staff's agreement that the rate case proceeding was a sufficient venue for review of a proposed PCA mechanism, but Staff did not agree (TR page 1329, line 17, through page 1332, line 9). If the Company wants to claim that this proceeding is where customers are provided an opportunity to participate, then the Commission should deny the PCA at this time due to the opposition of the customer groups involved in this proceeding.

E. BEFORE APPROVING A PCA MECHANISM, THE COMMISSION MAY WANT TO EXPLORE OTHER RATEMAKING OPTIONS

Although Staff's original recommendation remains the same (i.e., develop a customer group to look at the possibility of a PCA), Staff would encourage the Commission to consider the use of other ratemaking policies, such as a formal Performance-Based Rate (PBR) mechanism.

F. THE EVIDENCE PRESENTED IN THIS CASE SUGGESTS THAT AVISTA MAY NOT NEED A PCA MECHANISM ON A GOING-FORWARD BASIS

Finally, the evidence in this case suggests that Avista may not need a PCA to insulate itself from the effects of the costs of purchasing power to meet system demands on an ongoing basis. As Mr. Eliasson informed investors in a June 21, 2000 conference call (Ex. 17, page 10), Avista is building two new power plants, and will have an additional 250 MW of power available from the first of these plants to go online as early as the third quarter of 2001. Avista will have total control of the 250 MW of power produced by that plant (Ex. 17, pages 22-23). In addition, Avista informed investors, contrary to the testimony of Mr. Johnson (TR pages 2123-2125; page 2133, lines 1-12), that the Company would get access to 90 to 100 MW of power from Bonneville in 2001. As both Mr. Matthews (TR page 2039) and Mr. Johnson (TR 2102) testified, the Company currently needs to purchase only 90 MW of power, or nine to 10 percent of the Company's volumes, to meet its system load requirements.[6] Staff believes the addition of significant Company-owned generation, as well as the addition of BPA power, will significantly change the dynamics of Avista's energy needs and the need for a PCA mechanism on an ongoing basis. Staff also suggests that these facts may actually alter the viability of setting normalized power supply expenses in this proceeding. The Commission may chose to order the Company to file a case in which the new paradigm in power supply position is incorporated.

IV. POWER SUPPLY ISSUES–STIPULATED ADJUSTMENTS

A. WATER YEARS STIPULATION

Avista and Commission Staff differed over the appropriate period of time to use to normalize hydroelectric generation for ratemaking purposes. Avista contended that the 60 years from 1929-1988 should be used, while Staff recommended that the Commission continue to use the 40-year rolling average methodology, which would include the 1949-1988 period. The

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[6] In the conference call with the investors on June 21, 2000, Mr. Matthews estimated that the Company only needs to purchase five to eight percent of its load requirements to cover its system needs. Ex. 17, page 20. Later in that same call, Mr. Matthews stated that the Company is "already covered" for any need to purchase power for the second and third quarters of 2001. Ex. 17, page 22.

parties subsequently entered into a stipulation to resolve the dispute. The Commission has accepted this stipulation (Ex. 740).

Under the parties' stipulation, for the purposes of this proceeding, Staff and Avista stipulate to the continued use of the rolling 40-year average methodology, as previously adopted by the Commission in its Third Supplemental Order, dated April 4, 1986, in Cause No. U-85-36. The parties further stipulate that for purposes of this proceeding, Staff's adjustment reducing power supply expenses by $5,900,000 on a system basis related to the streamflow issue, as identified at Ex. T-540, Direct Testimony of Buckley, page 9, line 20, shall be revised to reflect an expense reduction of $2,950,000 on a system basis.[7] This results in an expense reduction of $1,976,000 for the Washington jurisdiction.

Avista has further stipulated that in any future proceeding, if the Company chooses to propose any modification to the continued use of the 40-year rolling average methodology, it will provide in its direct filing full documentation supporting its proposed change in methodology.

B. <u>MID-COLUMBIA ADJUSTMENT</u>

Commission Staff adjusted the purchased power proforma expense amounts for the Mid-Columbia projects (Wanapum and Priest Rapids) by a total net decrease of $222,000 on a system basis. This adjustment consists of a $231,000 decrease for the Priest Rapid Project and a $9,000 increase for the Wanapum Project. The adjustment reflects updated power cost forecasts which Avista provided to Staff in response to data requests (Ex. T-540, page 10; Exs. 165-66). Staff's

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[7]The term "system basis" reflects Avista's total costs for both Washington and Idaho. Unless otherwise specified, the percentage to be allocated to the Washington jurisdiction is 66.99%.

adjustment results in an expense reduction of $148,718 for the Washington jurisdiction. The Company does not oppose this adjustment (Ex. T-203, Rebuttal Testimony of Norwood, page 62).

C. FUEL CELL ADJUSTMENT

Commission Staff removed $71,000 on a system basis from the proforma power supply expenses related to gas used in a fuel cell pilot project. This results in a decrease of $47,563 [66.99%] for the Washington jurisdiction. Staff made this adjustment because Avista has not identified long-term benefits that the ratepayers will receive from this pilot project. The Company does not oppose this adjustment (Ex. T-203, pages 62-63).

D. CALCULATIONS RELATING TO UNCONTESTED ADJUSTMENTS

1. Settlement Exchange Power

Staff (Ex. 609, page 1 of 3, column k) and the Company's rebuttal case (Ex. 269, page 5 of 11, column k) include the same amount for the Settlement Exchange Power adjustment. However, as testified to by Staff, the adjustment needs to be modified to reflect the overall authorized rate of return and weighted cost of debt. This can be done by adjusting lines 28 and 29 in Ex. 611.

2. Proforma Potlatch July 2000-June, 2001

Staff (Ex. 613) and the Company are in agreement as to the methodology and calculation of the Proforma Potlatch July 2000-June 2001 adjustment. The difference relates to the non-firm rates developed in the power supply adjustment. Line 1 of Ex. 613 should contain the Commission accepted non-firm rates. Staff's recommended non-firm rate is shown in Ex. 542, line 5. The Company's recommended non-firm rate is shown in Ex. 210, page 1 of 3, line 5.

V. POWER SUPPLY ISSUES–CONTESTED ADJUSTMENTS

A. PGE CAPACITY CONTRACT ADJUSTMENT

The PGE Capacity Contract, the subsequent buydown (or "monetization") of that contract, and the treatment of that transaction for ratemaking are of paramount importance to this case. Commission Staff's PGE Capacity Contract Adjustment merely recognizes a regulatory reality that Avista has chosen to ignore, namely the fact that during the test year of 1998, Avista, through a complicated maze of transactions, assigned away its rights to receive annual payments of approximately $18 million from 1999 through 2014 in return for a lump sum, up-front payment of $143.4 million and annual payments of $1.8 million.[8] Avista has received, and will continue to receive, substantial benefits as a result of this test-year buydown (or "monetization," as Avista characterizes it), not the least of which is the significant benefit arising from the time value benefit of money received up-front. Yet, Avista's proposal in this case asks the Commission to pretend that this transaction never occurred; indeed, its direct testimony made no mention whatsoever of the buydown. Instead, Avista simply incorporates into the ratemaking equation annual "payments" that the Company is no longer receiving and will not receive in the future, a fact of which Avista was well aware when it filed this rate case in October 1999.

The Commission should reject Avista's proposal and accept Staff's recommendation to reflect in ratemaking the actual $143.4 million lump-sum payment received by the Company

[8] PGE (now owned by Enron) continues to pay $18 million per year, but not to Avista. Rather, it pays this to Spokane Energy, LLC, an affiliate of Avista. Spokane Energy, LLC then paid Avista $145 million and Avista paid Enron $1.6 million to approve the transactions, leaving Avista with a net up-front payment of $143.4 million.

during the 1998 test year. Staff recommends that these proceeds be used to decrease the annual proforma revenues from $18 million to $1.8 million (which is the actual annual amount the Company now receives), as well as to (a) buy out the remaining balance of the Rathdrum Combustion Turbine (CT) Lease, (b) fully amortize the remaining balance of the Wood Power Contract, (c) provide Avista with full recovery of the Potlatch purchase power contract costs, and (d) reduce certain of Avista's rate base items. (See Ex. T-540, pages 12-13; Ex. 543; Ex. 699). These recommendations are addressed in greater detail below and their monetary impact is shown in Appendix B (Proforma PGE Contract Restructure).

Staff notes that its original proposal, as set forth in Mr. Buckley's testimony, did not include calculating interest on the net cash balance between the date the Company received the $145 million payment and the beginning of the rate period (October 1, 2000). The Company would therefore receive the benefit of a substantial interest amount during that 21-month period. Based on Staff's revised rate of return of 8.64% over 21 months, this interest amount is $22.5 million.[9] Staff now recommends that interest be applied to the entire balance, as shown on line 1.5 of Appendix B, in light of Avista's clear lack of disclosure regarding the PGE monetization transaction.

[9]Staff originally stated that the interest amount, calculated at an 8.82% authorized rate of return, would be $12.6 million over 21 months. Staff now notes that this original calculation was actually a 12-month number ($143.4 million x .0882 = $12.6 million).

1. Avista Improperly Characterizes the Series of Transactions Involving its Assignment in 1998 of All its Rights and Obligations under the PGE Capacity Contract to an Affiliated Interest for $143.4 Million, and Proposes That Rates Be Based upon a Contractual Fiction That Does Not Exist

On June 26, 1992, Avista and PGE entered into an "Agreement for Long Term Purchase and Sale of Firm Capacity,"otherwise known as the "Capacity Contract." (See Ex. 170.) Under the Capacity Contract, Washington Water Power (WWP) agreed to sell 50 MW of capacity to PGE from November 1992 through October 1994, and to sell 159 MW from November 1994 until the contract's termination on December 31, 2016. In 1998, Avista received $18.72 million under the contract. In Ex. 152, filed with Avista's direct testimony in this case, the Company states that the "proforma" revenues under the "PGE #1 Capacity" contract for the 12 months ending June 2001 total $18 million.

But this characterization is entirely inconsistent with what actually occurred. In fact, during 1998 Avista entered into a complicated series of transactions in which it transferred all of its interest in the Capacity Contract to its affiliate, Spokane Energy, LLC (Spokane Energy). Ex. 225 demonstrates this clearly.[10] The Transfer and Assumption Agreement between the two entities, dated September 4, 1998, provides in part:

> . . .WWP hereby assigns, transfers, and conveys to [Spokane Energy,] LLC, and LLC does hereby ratify and assume, all rights, interest, liabilities, debts, duties and obligations of WWP under the Capacity Contract and all of its existing transmission rights necessary to perform the Capacity Contract.

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[10]Ex. 225 contains excerpted portions of Avista's Response to WUTC Data Request 288. The response in total contains two full volumes of documents pertaining to "Enron Capital & Trade Resources Corp.-- Monetization of Agreement for Long-Term Purchase and Sale of Firm Capacity Between Portland General Electric Company and the Washington Water Power Company" dated December 31, 1998.

> WWP and LLC hereby expressly agree that all terms, provisions, restrictions, duties and responsibilities under the Capacity Contract shall apply to LLC as if LLC had itself executed such Capacity Contract.

This agreement is signed on behalf of both WWP and Spokane Energy by Ronald R. Peterson, Vice President and Controller. WWP is also listed as the manager of Spokane Energy, acting through Mr. Peterson. Thus, this is clearly not an arms-length transaction but rather a transaction between affiliated interests.[11]

WWP and Spokane Energy subsequently signed a "Cross Receipt," dated December 31, 1998, acknowledging the Transfer and Assumption Agreement (Ex. 225). The parties stated:

> WWP hereby acknowledges receipt from Spokane Energy of consideration in the amount of $141,840,000 in exchange for the transfer of the Capacity Contract from WWP to Spokane Energy.
>
> . . .
>
> Spokane Energy hereby acknowledges receipt from WWP of the Capacity Contract in exchange for consideration paid in the amount of $141,840,000.

Again, the same individual, Ronald R. Peterson, signed on behalf of both parties to this intracompany affiliate transaction.

These transactions accomplished far more than Mr. Norwood asserts in his rebuttal testimony. He contends that the transfer of the contract to an affiliate, what he labels as a "monetization," was designed simply to "preserve the value of the original PGE sale contract," or was, in other words, "a financial arrangement to preserve the original revenue stream." (Ex. T-203, pages 7, 10, 14.) But as a result of the series of transactions, Avista no longer is a party to

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[11]This is consistent with Mr. Norwood's understanding that Spokane Energy is a subsidiary of Avista (TR 1609).

the Capacity Contract. Avista assigned away its rights in the contract during the test year to its affiliate in return for $141,840,000, an amount paid to Avista not by PGE but by Avista's affiliate, Spokane Energy.[12] In all, Avista received $145 million from Spokane Energy, and a net payment of $143.4 million (Ex. T-203, page 9; Ex. 5, page 51 (1998 Form 10K)).

Avista's proposed ratemaking treatment of this issue is premised on a contractual arrangement that has not existed since 1998, and it should be rejected. Avista's proposed treatment is not a "pro forma" adjustment at all, contrary to the suggestion in Mr. Norwood's Ex. 152. It is premised on a fiction. Avista stated in its FERC application that:

> In addition to the amortization "revenues" to be recorded monthly in Accounts 447.74 [power sales] and 447.71 [transmission], WWP intends to reflect an additional revenue credit for ratemaking purposes so that the total booked "revenue" in the accounts reflected for ratemaking purposes is equivalent to the revenue that would have occurred absent the assignment of the contract.

(Ex. 204, page 9.) The "revenues" to which Avista refers (the quotation marks are Avista's) are not revenues at all.[13] Nor do the recorded "revenues" bear any resemblance to the facts since 1998, which show that Avista receives only $1.8 million annually.

Staff's adjustment, by contrast, is a principled proforma adjustment fundamental to ratemaking: it adjusts the test year revenues to account for known and measurable changes–in

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[12] As part of the complex series of transactions in which Avista transferred all rights and obligations under the Capacity Contract, Avista now acts as the "servicer" of a collateral arrangement involving affiliate Spokane Energy, LLC and another entity entitled "Spokane Energy Funding Trust." (See Ex. 225) (Service Agreement). In addition, there were numerous other transactions involving Avista (WWP), Spokane Energy, LLC, Enron Capital & Trade Resources Corp, Enron Power Marketing, Inc., and Enron Corporation. (See Ex. 225, pages i-v.)

[13] The annual amortization "revenues" total $8,865,000, while the additional annual "revenue" credit Avista purports to "reflect" totals $7,335,000 (T-540, pages 15-16).

this case, the Company's known receipt of $143.4 million and annual revenues of $1.8 million. See WAC 480-09-330(2)(b)(ii). This is the pro forma adjustment, reflecting regulatory reality, that the Commission should adopt in this case.

2. Avista's Proposed Ratemaking Treatment of PGE's Buydown of the Capacity Contract Improperly Withholds from Ratepayers the Benefits of the $145 Million Lump-sum Payment That Avista Received in 1998

Avista proposes to "flow through to customers the revenue stream from the original PGE Capacity Sale Contract." (Ex. T-203, page 7). According to Avista, this is consistent with the Company's stated reasons for entering into the PGE buyout transactions. Mr. Norwood argues that the Company's "primary" reason (and perhaps only reason)[14] for the affiliate transactions through which it received an up-front payment of $143.4 million was Avista's belief that PGE might default under the terms of the original contract (Id., page 9; TR 1599). Mr. Norwood states that Avista thus intended only to preserve that revenue stream, and did so. But this argument also assumes that Avista would have had no effective legal recourse against PGE, had that company chosen to default on its obligations if it later learned that it had made a bad bargain with Avista (that is, if PGE's agreed-to sales price turned out to be above market in the future). The record does not support such an assumption. In turn, this calls into question Avista's limited description of the benefits it anticipated as a result of the PGE buydown.

Rather, the record strongly suggests that the Company believed it would receive substantial benefits–not merely the preservation of a revenue stream, through an up-front

[14]Mr. Norwood stated on cross-examination, "There may have been other reasons. I guess I can't think of any right now." (TR 1599.)

payment. First, the Company fails to account for the time value of money resulting from the receipt of the $145 million. Mr. Norwood claims that the net benefits arising from the original revenue stream, approximately $16.2 million per year ($18 million annually minus the $1.8 million annually that the Company now actually receives), are equivalent to the benefits arising from the up-front payment of $145 million. But he admitted that to reach this result, one must assume a discount rate of 7.83%, the rate he used. And he further admitted that he did not arrive at that percentage through any independent analysis or study. Rather, he simply backed into the number because it would make the two revenue streams "equal":

> Q: Mr. Norwood, have you calculated what the net present value of a $16.2 million revenue stream for 16 years would be at any discount rate other than 7.83%?
>
> A: No. When I did my calculation, I calculated what the implicit discount rate would be to arrive at the $145 million, so no.

Only by using this very low interest rate does the mathematical present value calculation result in zero monetary benefits as a result of the transaction. If a higher rate such as the Company's authorized rate of return were used, the benefits, when comparing the actual transaction's present value with the present value of the Company's proposal, would significantly increase. An even greater level of benefit results if a higher "customer" discount is used. Yet under the Company's proposal, none of these additional benefits are recognized and flowed through to the ratepayers.

Staff also notes that the Company indicated, in a detailed internal memorandum outlining options for the "Buydown of [the] PGE Contract," that it envisioned benefits of up to $32 million arising from such a buydown (Ex. 545, page 23). Avista further identified several uses that could be made of the monetization proceeds. Those uses were detailed as follows:

> The Money
> - The money could be used for many purposes
>   - Purchase additional generation
>   - Purchase gas and/or electric LDC property
>   - Invest in opportunities that return higher than utility rate-of-return
>   - Invest in fairly safe revenues. Money market, bonds, overnight funds, etc.

(Id., page 38.) Quite notably, the Company recognized that "In the past, all margins from these types of sales have been flowed through to retail customers." (Id.) The Company memorandum further stated, however, that "A good case can be made to retain a portion of the margins from this contract. This restructuring provides that opportunity." (Id.)

Mr. Norwood now contends these projected benefits were developed in the "early stages" of the monetization transactions, and should simply be dismissed (Ex. T-203, page 12). To the contrary, Staff believes that significant additional benefits are conferred by the PGE buydown. These benefits, furthermore, should be passed on to the ratepayers. This is the standard ratemaking approach: revenues from the sale of power should be flowed through to the ratepayers since the customers have paid the costs of the facilities that generated the sales. Moreover, in circumstances where Avista has paid an up-front sum of dollars to buydown an existing over-market purchase power contract, the Company has requested recovery of those dollars from ratepayers. For example, Avista in this case requests recovery of the buyout costs associated with the original Wood Power contract. Staff's recommendation to use the proceeds from the PGE monetization transactions is only a logical extension of this practice, and should be adopted here.

3. Avista's Wholly Inadequate Notice to the Commission of this Highly Complex and Significant Series of Transactions, Involving the Receipt of $143.4 Million for the Buydown of the PGE Capacity Contract, Provides Evidence That the Company Intended to Retain All of the Benefits of this Transaction, to the Exclusion of the Ratepayers

Staff remains quite concerned that Avista gave virtually no notice to the Commission of a series of transactions involving not only PGE and Enron, but its own affiliated interest, through which the Company received a net lump sum payment of $143.4 million. Not only did the Company fail to directly inform the Commission at the time of the transactions, it also completely avoided apprizing the Commission of these transactions when it filed its direct testimony in this proceeding. Instead, Avista filed testimony stating that it had made a "pro forma" adjustment to the revenues the Company received in 1998, implying that it would continue to receive such revenues from PGE during the July 2000-July 2001 rate year when, in fact, Avista's contractual ties to PGE were severed December 31, 1998. Staff believes the Company's virtual silence on this highly significant matter is evidence that the Company intended to retain the benefits of the transactions.

Avista's transactions with Spokane Energy an affiliated interest, implicate chapter 80.16 RCW and former WAC 480-146-090 and -091, which required that such transactions be filed with the Commission. Yet Avista never made such a filing. For this reason, Staff recommends no amortization prior to the start of the rate year.[15]

Avista's own staff members recommended to Gary Ely, Jon Eliason, and Ron Peterson that "At a minimum, the Commissions [WUTC and Idaho PUC] and staffs should be informed of the contract buydown and our proposed accounting and ratemaking treatment." (Ex. 545, page 24.) Avista, however, did not do this. Though the Company filed an application with the Federal Energy Regulatory Commission (FERC) in September 1998, it made no concurrent filing with the WUTC.[16] Mr. Norwood stated: "I think historically in the past we tend to notify the Commission of these things." (TR 1678.) Indeed, Avista has done so, particularly when the Company has incurred costs rather than received revenues. As Mr. Buckley pointed out, Avista had sent a letter informing the Commission of an earlier Wood Power purchase power contract buyout that represented approximately $9.5 million in costs to the Company. (Ex. T-540, page 15.)

Avista contends that the transactions were "disclosed" in its 1998 Form 10K Report. That report, however, contained merely a footnoted two-sentence paragraph that did not directly

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[15]Should the Commission accept the amortization of the $145 million from the inception of the transaction, the balance to be reflected in Appendix B, line 1, would be $129.5 million.

[16]Mr. Norwood stated that "As far as a specific letter or formal notification, there was no formal notification directly to the Commission other than a notice that they probably received from FERC related to a filing with the Federal Energy Regulatory Commission."

In fact, the Notice of Filing issued by FERC on September 11, 1998, was a terse, two-paragraph statement containing only a minute description of only part of the transaction, and it did not refer to any proposed ratemaking treatment for the transaction (Ex. 204, page 1).

reference the PGE/Spokane Energy transactions.[17] Only following subsequent data requests in this proceeding by Staff and ICNU did Avista respond with full information regarding the transactions: documents approximately six inches in height filling two full volumes. (See TR 1687) (Avista Resp. to WUTC Data Request No. 288). (See also Ex. 225) (excerpts and table of contents from this Data Request response).

Finally, Avista contends that it included, in the June 30, 1999 Commission basis report filed with the Commission, an adjustment for the monetization (TR 1606). That report, however, which has workpapers approximately one and one-half inches thick, contained but one page with one line mentioning the transaction, and it did not include any adjustment for the transaction.

Based on a thorough review of this matter, Staff does not concur with the Company's contention that it properly informed the Commission or Staff of the PGE contract buydown. Nor does Staff concur that this contract conferred no additional benefits to Avista apart from preserving a previous revenue stream. The $143.4 million payment the Company received should be recognized for ratemaking purposes by applying it to the Potlatch, Rathdrum, and Wood Power contracts. Staff further recommends that the following items also be netted against the $143.4 million: (1) the Nez Perce Settlement payment (Ex. T-203, page 20, with which Staff

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[17]The 1998 Form 10K footnote simply reads: "In December 1998, the Company received cash proceeds of $143.4 million from the monetization of a contract in which the Company assigned and transferred certain rights under a long-term power sales contract to a funding trust. The proceeds were recorded as deferred revenue and are being amortized into revenues over the 16-year period of the long-term sales contract." (Ex. 5, page 51.)

The footnoted paragraph in the 1998 Form 10K Report led Staff to ask data requests of Avista. The Company's responses still made no mention of the transaction (Exs. 218, 219, and 220). Only later, in response to WUTC Data Request No. 288, did the Company provide such documentation.

concurs), as shown on line 4.5 of Appendix B, and (2) Weatherization and DSM Investment, as shown on lines 8 and 11 of Appendix B. Regardless of which adjustments the Commission chooses to adopt, the remaining amortization period should be 14.25 years. See Ex. T-203, page 21, with which Staff concurs.

B. <u>POTLATCH PURCHASE ADJUSTMENT</u>

The Potlatch purchase power contract will expire on December 31, 2001. The average price included in the power supply proforma year expense amount under this contract is 48 mills per kilowatt. This price does not reflect current market rates, as indicated by the Company's own recent purchases. Staff believes it would be improper to embed this over-market priced purchase into base rates indefinitely, particularly given the historically long period between general rate cases. Staff, therefore, has adjusted the expenses associated with the Potlatch contract downward, applying an energy rate of 29.7525 mills, the price the Company paid in its recent TransAlta purchase, to the same annual proforma energy amount used by the Company. The $14.105 million adjusted cost of the purchase results in a decrease in annual proforma expenses of approximately $8.5 million. Staff's proposal is a proforma adjustment to account for known and measurable changes to test year data not offset by other factors. The Company has not rebutted this adjustment, or the rationale underlying it, for purposes of setting normalized power supply expense levels.

In addition to this expense adjustment, Staff recommends that the Commission credit $11.4 million (shown in Appendix B, line 2) of the PGE Capacity Sale cash payment to the Company to reflect the difference between the adjusted rate and the actual contract rate from the beginning of the rate period (October 1, 2000) until the end of the Potlatch contract period (December 31, 2001). Staff emphasizes that this use of a portion of the PGE monetization proceeds will make Avista whole by providing the Company full recovery of the costs associated with the Potlatch contract. Staff did not make a present value calculation to adjust the $11.4 million payment to reflect the fact that the Company is, in effect, partially recovering the cost of this purchase up-front. This affords Avista an additional benefit.

If the Commission chooses not to adopt Staff's recommendations regarding the PGE monetization transaction, Staff continues to recommend that the rate associated with this above-market purchase power contract be adjusted for ratemaking purposes in order to ensure that these costs not remain embedded in base rates when the contract terminates shortly after the rate year.

C. RATHDRUM LEASE ADJUSTMENT

Staff recommends a $5.75 million adjustment to system proforma power supply expense associated with the annual lease payment for the Rathdrum turbine. This adjustment reflects only the annual lease costs, not operating or fuel expenses, and is based on crediting a portion of the $145 million PGE monetization transaction payment to the remaining lease balance of approximately $55 million (shown in Appendix B, line 4). (See Ex. 172) (Response to WUTC Data Request No. 72). Staff's recommendation resolves all of Staff's concerns regarding the acquisition of Rathdrum and the ratemaking treatment of the lease itself. Staff believes a credit against the PGE monetization payment is appropriate, not only as a method for treating the up-front revenue obtained in that transaction, but also because Avista has consistently relied upon the benefits of the original PGE capacity sale to justify the acquisition of Rathdrum. In particular, the Company has linked the two projects together in several of its business documents supporting Rathdrum; and the Company argues that the revenues from the original PGE capacity contract, when compared to the costs of operating Rathdrum, show that Rathdrum is beneficial (Ex. 171; Ex. T-203, pages 8-9).

On rebuttal, Mr. Norwood asserts that Staff was deficient in not carrying out sufficient analysis related to the proposal to "buy out" the Rathdrum lease, and that Staff improperly wishes to "micro-manage" the Company. He further appears to contend that Staff's proposed ratemaking treatment does not recognize the value of the Rathdrum turbine and the revenues associated with the original PGE capacity sale (Ex. T-203, pages 8, 14-15).

These assertions are unfounded. First, Staff's recommendation is based on the simple and straightforward principle that, after adjusting the annual revenues associated with the new PGE capacity arrangement downward (from $18 million to $1.8 million), it is entirely appropriate to identify, for ratemaking purposes, various ratebase and expense items that can be reduced with the up-front $145 million payment that Avista received in the PGE transaction. Despite its claims of "micro-management," the Company offers no alternative uses for these proceeds other than to assume that they do not exist. Second, a simple comparison of the approximately $5.75 million annual lease payment and the $55 million lease balance leads Staff to conclude that reducing these levels of expenses is a proper use of the PGE proceeds. Third, while Staff recognizes that the Rathdrum turbine may be economically favorable, based on the <u>original</u> terms of the PGE contract (<u>i.e.</u>, $18 million in annual PGE revenues compared to $9 million in annual Rathdrum costs), Avista is now receiving only $1.8 million annually from the

PGE contract. Given this significant change in circumstances, the economic benefit of Rathdrum is far less certain.

The Company, on cross-examination, criticized Staff's proposal as one "to buy out a very inexpensive financing arrangement," and contends that the cost of refinancing would not be favorable (TR 1680-81). But this criticism misses the mark. Staff is not proposing that Avista obtain additional financing for the purpose of buying out the Rathdrum lease. Rather, Staff simply recommends that for ratemaking purposes, the cost of buying out the lease be credited against the up-front PGE monetization payment.

If, however, the Commission chooses to maintain the present lease payments for ratemaking purposes, and not buy out the lease, Staff recommends that an equal amount of the up-front $145 million payment ($55, 277,777) be applied toward reducing Avista's generation rate base.

D. WOOD POWER AMORTIZATION BUYOUT

Staff recommends a $1,188,000 adjustment to proforma power supply expense related to the elimination of the annual amortization expense associated with the Wood Power contract buydown. This adjustment is made possible because Staff has recommended that the unamortized balance of just over $5 million be paid down using the proceeds from the PGE monetization transaction. (Shown in Appendix B, line 3.)

No adjustment to rate base is necessary as a result of eliminating the unamortized balance since Avista neglected to include the unamortized balance in rate base. In Staff's view, a credit of that amount to the Company provides it with a benefit as the proceeds will be used to "remove" an item that, we believe, was erroneously excluded from rate base. Otherwise, the unamortized balance would not have been included for ratemaking and the $5 million could have been used to write down additional generation rate base as one way of treating the PGE monetization proceeds.

Avista provided no rebuttal to this adjustment other than opposing Staff's entire proposal regarding the use of the PGE transaction monies.

E. DISPATCH CREDIT ADJUSTMENT

The purpose of Staff's dispatch credit adjustment is quite simple. The dispatch model which both Avista and Staff have used in this proceeding is a monthly model. Hence, that model does not, and cannot, capture any flexibility within a month, week, or day to maximize sales revenues or minimize purchase costs by operating the Company's resources in the most optimum manner. The Company, in responses to Staff's data requests, acknowledged:

> The Company's Dispatch Simulation Model dispatches resources on a <u>monthly</u> basis based on the incremental cost of the resource, the market price and the availability of the resource. (Ex. 158; emphasis in original)
>
> . . .
>
> The "Net Purchase" and "Net Sales" amounts are derived in the Simulation Dispatch Model, which is a monthly average model. Because it is a monthly average model there is no breakdown between on-peak and off-peak hours. (Ex. 159.)

On cross examination, Mr. Norwood explained further the limitations inherent in the Company's dispatch model:

> That refers to the secondary – the net purchases and the sales that the company makes. When the model dispatches thermal resources against the market to serve load, it does not distinguish between the heavy load hours and the light load hours. So what you see is essentially a flat product. So the output

> you get for short-term purchases, short-term sales, are not distinguished between heavy load and light load hours. That's what this response [in Ex. 159] is communicating.

(TR 180.)

And this is precisely the basis of Staff's dispatch credit adjustment: it better reflects the actual operating characteristics of the Company's own generating resources compared to the simple monthly dispatch model currently used by the Company. Avista itself has recognized the need to account for heavy-load and light-load hours: while stating that "this will not resolve the whole issue of market prices correlated to hydro conditions," Mr. Norwood confirmed in response to Commissioner Gillis that "We are in the process now of developing an hourly model . . . and we are in the process of finishing up that hourly model, which will take into account the hourly output, hourly operation of our system." (TR 1660.)

Despite these acknowledgments, Avista largely attempts to discredit Staff's dispatch credit adjustment by creating confusion over its purpose and mischaracterizing its effects. In fact, Mr. Norwood's rebuttal testimony addresses primarily the question of the overall level of short-term energy prices, an issue that is not relevant to Staff's adjustment. (See Ex. T-203, pages 47-53). Thus, while Staff seriously disputes Avista's repeated contention that "the Company has already significantly understated its power costs,"[18] (id., pages 48, 53) this

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[18]Staff finds this contention quite curious, however. If Avista truly believed that its own proforma power cost figures are not valid, then one can presume that Avista would file a new rate case with updated data that reflects those higher costs–presuming, of course, that the Company can demonstrate that such higher costs are representative of future conditions, and are not based simply on speculation or short-term variations. Avista, of course, has not elected this option, and Staff finds it implausible that Avista would purposely file rates "significantly" below its actual costs. In any event, the overall level of costs is not relevant to Mr. Buckley's dispatch credit adjustment.

contention is of no consequence here. Mr. Buckley has incorporated adjustments to short-term sales and purchase amounts resulting from the simple dispatch model as a means to derive an estimate of the benefits accruing from actual operational flexibility, not as an end in itself. The basis for this adjustment is independent of model results or actual price levels the Company experiences. In fact, any increased volatility and high differences in prices between off-peak and on-peak hours, a condition to which Mr. Norwood makes reference,[19] would only serve to increase Staff's recommended adjustment, as it is the relative difference between on-peak and off-peak hours that matters when gauging the advantages of operational flexibility.

Moreover, Staff disagrees with Avista's assertion that modeled results must be compared with current or expected future market conditions to assess whether market prices from the model are reasonable. The Company appears to misunderstand some of the most fundamental characteristics of its own dispatch model. The Dispatch Model is not one that attempts to mimic regional generation in order to estimate market prices given a particular set of inputs.

The average sales and purchase prices in the model are obtained by applying different levels of surplus energy, dependent on the water year, to different "bands" of surplus energy. Each "band" is assigned a different market price and represents the markets available for Northwest surplus energy, ranked by priority (Ex. T-151, page 10). The band prices range from $35/MWh under limited regional surplus conditions to about $8/MWh when significant surplus exists. The higher numbers represent the incremental costs of operating high-cost generating

[19] Mr. Norwood contends that "Not only have the average short-term market prices been increasing, there has also been a sharp increase in the volatility in short-term prices." (T-203, page 51).

units and of purchasing energy from the Southwest. The lowest cost of $8/MWh represents the incremental cost of operating Colstrip, which could be displaced when a large surplus exists. A strict comparison between model results and current or expected market prices, therefore, is not an "apples-to-apples" comparison.

Avista devotes significant time criticizing the methodology Staff has employed in calculating the amount of the dispatch credit adjustment, rather than the sound and clear rationale for the adjustment itself. Staff's direct case discussed alternative methods to identify the proper benefit of the hydroelectric system's operational flexibility. One such method included modeling using an hourly production cost model. Staff stated that in the limited time available, it could not carry out and complete such a study.

But Avista's concerns as to the best and most accurate methodology have now been answered, persuasively, through a comprehensive and compelling study carried out by Avista and provided by the Company's own witness, Mr. Dukich. (See Ex. 88.) In fact, this study, dated May 31, 2000, carries out the exact analysis Mr. Buckley identifies in his testimony. It shows in detail the benefits gained through the hourly dispatching of resources during off-peak and on-peak hours, and demonstrates that these benefits are far greater than Staff's original more conservative estimates:

> Attached are several charts and ProSym output sheets that quantify the energy value of flexibility for the Clark Fork hydro system. The value of flexibility for energy production only is approximately **$4,500,000 per year.**

(Ex. 88, page 1.) (Boldface type in original.) Moreover, Avista's study recognizes that the benefits may be even greater:

> Only the value of energy due to flexibility of the Clark Fork system is calculated. I [the study's author] ignored capacity benefits and all ancillary services benefits. **The capacity value alone could add an additional $2,000,000 to the value of flexibility.**

(Id.) (Boldface type in original.)

The study, submitted by Avista's Resource Optimization Department, uses a chronological hourly production cost model to "calculate the flexibility value of the Clark Fork hydro system." It compares the value of a flexible hydro system with that of a "run-of-the-river" system. The latter is the manner in which the Company's simple dispatch model operates, where a fixed amount of energy is assumed to be produced every month with no ability to alter production throughout a day, week, or month. The amount of monthly energy is compared to load to calculate a monthly sales or purchase power amount.

Avista's study has additional significant refinements, including the use of a single average year to determine generation, as Mr. Buckley suggested should be done in his testimony (Ex. T-540, page 31), and the use of more recent high-load hour and low-load hour energy prices. Moreover, the study explicitly recognizes that "the on-off peak differential value is important." (Ex. 88, page 1.) The differential in the Company's study is based on actual market prices rather than information from the Bonneville Power Administration (BPA). As Mr. Buckley stated, this is precisely the type of study that Staff would have carried out given the time and resources to do so (Ex. T-540, page 31). This is also the type of model that Avista indicates it intends to develop for future ratemaking purposes.

Staff believes this study, offered by the Company itself, provides a better, more qualitative estimate of flexibility benefits than the methodology employed in Staff's direct case, which necessarily was based upon certain general assumptions regarding the amount of energy that could be moved to maximize the benefits from the Company's hydro system. Avista's study, by contrast, identifies those benefits for the Clark Fork river projects using an hourly production cost model, as well as actual market price high-load and low-load hour differentials.

For these reasons, Staff recommends that the Commission adopt the flexibility value presented in Avista's own study, a minimum of $4.5 million system-wide, rather than the $1.6 million that Staff initially proposed. Staff notes that even this figure is conservative given the fact that Avista has identified an additional $2 million in potential system-wide benefits from capacity value.

F. COLSTRIP AVAILABILITY

Staff has made an adjustment of $428,000 to proforma power supply expense related to changing the availability of the Colstrip Unit 3 plant. Ex. 162 shows a significant outage in 1993 due to transmission system problems. This single event was the principal cause for a Unit 3 equivalent availability factor of just under 64% in 1993. This compares with a more typical range of 85% to 95% for the years prior to and after 1993.

For ratemaking purposes, Staff recommends the use of a four-year average from 1994 to 1998. Not only does the use of the more recent figures eliminate the anomalous 1993 values due to transmission values, it also reflects the most current operation practices. Using the entire range of historical data would not accomplish these objectives. The average equivalent availability from 1994 through 1998 is 86%.

Avista attempts to rebut Staff's recommendation by stating that while plants may operate at high availability levels for a period of years, "they do break down from time to time." While Staff agrees with this generalization, the event that lowered the availability of the Colstrip 3 Unit down to 63% appears to be a non-recurring, transmission-related event, not "normal" plant operation.

The Company on rebuttal also compares Staff's proposed availability with that of "similar size generating plants, with a similar vintage, and with similar equipment." (T-203, page 61. In response, Staff points out three facts. First, Staff's recommendation is derived from actual operation of the Colstrip Unit 3 plant, not "similar" plants. Second, the North American Reliability Council (NERC) data to which Mr. Norwood refers are averages of several plants. In any such set of data there are some plants above the average and some below; 86% is not an unreasonable departure from the NERC average of 82.98%. Finally, NERC data is used to determine reliability; the safe and reliable operation of the entire system. One would expect the amount reported for reliability purposes to be extremely conservative. The availability percentage Staff recommends is for the purpose of setting retail rates. In Staff's opinion, it much more closely represents the actual operation of the plant.

G. CAPACITY PURCHASE ADJUSTMENT

Staff recommends that the proforma power supply expense be adjusted by $955,000 to reflect the Company's failure to demonstrate need for the specific capacity levels represented by this proforma expense amount. Avista has simply shown no connection between the test year, or recent historical levels of short-term capacity purchases, and the amount Avista includes as a proforma power supply expense for a normalized test year. Avista has only provided a description of 1998 purchases, some historical data, copies of test year agreements, and a discussion of the Company's capacity purchase policy. No tie-in to normalized power supply needs has been made.[20]

Avista also has proposed eliminating, for ratemaking purposes, certain transactions it denominates as "commercial trading activities." But in doing so, Avista undertook no analysis to distinguish those historical capacity purchases that were necessary to address the Company's system requirements and those that may have been made to address other purposes, such as "commercial trading." This again underscores the fact that Avista has not identified normalized capacity needs, and that simply looking at historical purchases may not be representative of those needs.

On rebuttal, Avista goes to great lengths to describe its Integrated Resource Plan (IRP) process, and lectures that Staff should be familiar with the Company's capacity requirements. Staff does not dispute the potential need for capacity purchases. Staff's concern is that Avista has not adequately supported the level represented by nearly $1 million in annual power supply expense. A single "tabulation" from a Least Cost Plan (Ex. 211, page 1), or a draft of a Least Cost Plan (Ex. 217), does not constitute adequate support. The tabulation is done on a yearly

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[20]Staff further notes that it did not remove short-term capacity purchases from the listing of purchase transactions Staff used to derive its market transaction adjustment. Had Staff removed these capacity purchases, the total purchase amount would have been lower, and the market transaction adjustment larger. If the Commission adopts Staff's methodology for estimating market transaction expenses, removal of the short-term capacity purchases is necessary to prevent a double counting of the expenses associated with those purchases.

basis and is quite general in nature. One cannot assume from the document that any particular amount of capacity is required.

For example, the table may show that Avista has an energy and capacity deficit over the course of a given year. However, as the table is very simple, it does not show Avista's actual needs after the Company acquires short-term energy to meet its energy requirements. These short-term purchases are firm for the time frame in which they are acquired and would, therefore, include the capacity associated with the purchased amount depending on the load factor. The Company's "tabulation" or "support," however, does not capture this reality and the capacity needs are not adjusted accordingly.

Staff disagrees with Avista's apparent belief that the Least Cost Plan process is the process in which all questions regarding capacity purchases should be addressed. It is the Company's burden to demonstrate that the proforma level of power supply expenses are appropriate, irrespective of the Least Cost Plan process. Avista has failed to meet that burden, and Staff's recommended adjustment should be adopted.

H. CENTRALIA POWER SUPPLY EXPENSE

Staff recommends that the power supply expenses associated with the Centralia plant remain as is, for ratemaking purposes, until Avista makes a sufficient showing regarding the long-term needs and costs involved in replacing Centralia power. At the time Staff filed its direct testimony, the Company had not made the final decision to sell Centralia. The Company's initial case, as did Staff's, included the expenses associated with Centralia in determining annual normalized power supply expenses and rate base levels. Staff's position was based not only on the fact that no sale had yet been made, but also on the Company's failure to demonstrate that its acquisition of a short-term purchase power contract (the Trans Alta purchase) from the buyers of Centralia was the least cost option available to the Company.

Staff's concern is that the short-term contract will be embedded in the Company's base rates without any showing of prudence. The short-term Trans Alta contract results in a $4,148,000 million (Ex. 448, page 1, line 25) increase in revenue requirements compared to the existing Centralia revenue requirement. The Company agrees that the Trans Alta purchase represents only a temporary replacement and is not a long-term solution for replacement power (T-203, page 54). Staff believes that this short-term solution should not be used for the purpose of setting base rates.

We emphasize that Staff does not take issue with the price or rate of the Trans Alta contract. Staff is aware that on cross-examination, counsel for Avista over and over focused on the price of the contract (TR 1299, 1303-04). That misses the point. Staff's position is that Avista has made no showing that the acquisition of a 200 MW block purchase for the period of July through March is the appropriate acquisition to be made for replacing Centralia. Avista has provided no studies analyzing the actual size or shape of the power that might be needed to replace Centralia based on the Company's existing resource portfolio or any other least cost option. Avista has only provided information related to the various index prices for a 200 MW block of energy. This is a significant issue because these costs, if adopted, would then become embedded in rates until the next rate case.

Avista claims that it has made a sufficient showing of prudence, reciting the various "facts" surrounding the Trans Alta purchase (Ex. T-203, page 55). Avista contends that it conducted a number of market assessments to determine heavy load products, flat products, and seasonal products that were available to meet wholesale need (Id., page 57). Avista claims that it has considered economic dispatch, load factor, and seasonality in that the replacement power selected was a nine-month product (Id., page 58). Finally, Avista points to Exhibit C-214 as the "economic analysis comparing the cost of the Trans Alta purchase with other alternatives." (Id.)

But this is nothing more than an after-the-fact justification of the Trans Alta purchase. Avista does not show how it actually "analyzed" its list of factors and alternatives; the analysis it references simply compares the Trans Alta block purchase with other market alternatives. The Company provides nothing to support its initial premise that a seasonal high-load 200 MW block of energy is the least cost option for the long-term, compared to other options. These options might include a combination of generation, additional purchase power contracts, or DSM.

The price the Company paid for a 200 MW block of energy is not the issue. The issue is that the Company has not shown that its decision to purchase this size and shape of replacement power is the least cost option. Staff's recommendation, which is to continue to include the power supply expenses associated with the Centralia plant for ratemaking purposes, holds the ratepayers harmless from the Company's failure to make the required showing of prudence.

I. MARKET TRANSACTION ADJUSTMENT

There appears to be much confusion regarding Staff's market transaction adjustment.

The principle is simple. Staff has attempted to input margins associated with normal business transactions that the utility should be carrying out in its ordinary course of business, using all of the resources available to Avista. These resources include knowledge of regional and Western energy markets as well as the favorable position of Avista's transmission system.

Avista asserts that it has removed from the ratemaking process transactions that it labels as "short-term commercial trading activity" or "market transactions." Avista alleges that all of these transactions "are speculative in nature, are not related to the operation of the Company's system resources or in serving retail load." (Ex. T-203, page 22). But what Avista has actually done is simply to remove all revenues associated with <u>any</u> transaction that does not fall out of its already deficient Dispatch Model. To assume, as Avista does, that the normalized sales and purchase amounts from the model represent the total utilization of Company resources is clearly erroneous.

Avista further confuses the issue through its repeated claims that anything it chooses to label as "commercial activity" is, by definition, "too speculative" for ratepayers to bear. During cross-examination, Mr. Norwood spoke about the "very competitive, very volatile" market (TR 1638), and then said:

> And you may have seen the recent press release that the company issued stating that the company is no longer going to enter into wholesale transactions that are unrelated to operating [the] system for our customers.

(TR 1639.)

That is all well and good. Staff does not dispute Avista's intent to cease engaging in the types of transactions that led it to incur a projected $90 million loss during the second quarter of

2000. Those transactions appear to be "futures" type trading (e.g., the Company agrees to sell blocks of power at a future date without having a firm commitment of power on hand to back it up.) The transactions Staff proposed to use in determining normalized net revenues, on the other hand, simply have not been shown to be outside Avista's Corporate Financial Risk Policy. Section 6 of that document sets forth Avista Utilities' Resource Optimization Risk Policy. That policy states, in part:

> The primary focus of Resource Optimization is to acquire power resources on behalf of its customers, and to operate those resources, both owned and contracted, in a manner which optimizes the value of the resources to customers and shareholders. These activities include selling surplus at maximum value. This includes hedging transactions and other energy trading activities that occur as a direct result of the prudent management of resources and result in additional value to customers and shareholders.

(Ex. 188, page 57.) (Emphasis added.) Section 6 then describes policies related to what risk is addressed, the limits of risk, the products that are authorized, how trader performance is benchmarked, and what reporting is required.

In this context, Avista engages in numerous "short-term commercial transactions," and will presumably continue to do so. Indeed, to do so is, as Avista recognizes, "a direct result of the prudent management of resources." Mr. Matthews, in fact, set forth examples of short-term arrangements with neighboring utilities that take advantage of the Company's transmission system and delivery point options and that only entail minimal risk (TR 148-49). The Company engages in numerous other simple short-term buy-sell arrangements, also with minimal risk (Ex. T-540, page 42).

Having thus established Avista's clear failure to prove that all of its "short-term commercial transactions" are too risky to be included in the ratemaking process, the remaining question concerns the appropriate methodology to estimate the level of these transactions. Staff has calculated a normalized revenue amount. Staff started with a listing of <u>all</u> sales and purchase transactions in which the Company participated (since the Company can identify none in particular as "too speculative"). Staff then attempted to subtract out the normalized level of sales and purchases that the simple dispatch model captures, before deriving a normalized level for those transactions not captured by the model. This results in an estimate of annual short-term sales and purchase transaction levels for the past few years <u>above</u> what the simple dispatch model calculates. The remaining sales and purchase amounts are then used to calculate an annual revenue amount.

Avista on rebuttal criticizes Staff for using "identical short-term sales and short-term purchases figures each year." (Ex. T-203, pages 22-23). Staff maintains that, given the available data, this is the only way in which one can attempt to derive <u>normalized</u> net revenues associated with transactions not captured in the Dispatch Model. Avista also criticizes Staff's methodology for not indicating the trading margins that occurred in the years observed and for not having a detailed analysis for each of the variables included. Staff finds this claim curious since the Company itself provides no basis or analysis whatsoever for its proposal to remove significant net revenues on a normalized basis from the ratemaking process, other than to label them, without support, as "speculative."

Mr. Norwood appears to present an alternative method of calculating net revenues at page 29 of his rebuttal testimony (Ex. T-203). Staff does not concur with this calculation. First, the data the Company used is different from that which Staff used, and appears to be based on informal records. Second, Staff believes that the FERC fees the Company nets from the gross margin amount are already included in other accounts that form the basis for the Company's revenue requirement. Finally, Staff does not concur that a sharing mechanism as proposed by the Company is proper. A sharing mechanism would only be appropriate if actual revenues were being tracked on an annual basis, which is not the case here.

Staff's recommendation does not use the annual <u>average</u> net revenue amount that could have been calculated from the data. Instead, Staff used the 1999 amount, which is the lowest of the three years observed. Staff did so to make a conservative estimate of the level of normalized net revenues. In this way, the Company is at less risk for periods in which the net revenues from these transactions are minimal, and the Company is given an additional incentive in the event in can obtain greater levels of net revenues.

VI. MISCELLANEOUS ISSUES

A. <u>PROFORMA RESTATE DEBT INTEREST</u>

Staff (Ex. 612, page 1 of 2 (electric) and 2 of 2 (gas)) and the Company are in agreement as to the methodology and calculation of the Proforma Restate Debt Interest adjustment. The difference relates only to the levels of rate base included in each parties case and the weighted cost of debt rate recommended in each case. This adjustment needs to be recalculated based on the Commission allowed rate base and weighted cost of debt.

**B.	<u>CONVERSION FACTOR</u>**

The only difference between Staff and the Company related to Conversion Factor is the treatment of Franchise Fees. If the Commission accepts the Company's proposed treatment of Franchise Fees the conversion factor to be used is shown in Exhibit 269, page 3 of 11 (electric) and Exhibit 270, page 3 of 9 (gas). If the Commission adopts Staff's recommended treatment of franchise fees, the conversion factors are shown in Exhibit 617 page 1 of 2 (electric) and 2 of 2 (gas).

**C.	<u>DEMAND SIDE MANAGEMENT (DSM) PROGRAMS AND TARIFF</u>**

As Joelle Steward testified (Ex. 663), Commission Staff believes that Avista has demonstrated the prudence of its past DSM program expenditures, and recommends that the Commission make a finding to that effect. Avista has also shown that its DSM portfolio was cost-effective on an overall basis. Staff also recommends that if the balance in the tariff rider fund is not reduced to a reasonable level (as set forth in Ex. 664) by mid-year 2001, that the Company be directed to file a rider rate adjustment that more closely matches its actual DSM program expenditures. Staff requests that the Commission include in its order a specific statement (as recommended in Ex. 663, page 7) that the Company must bear the risk of undercollection of funds through the tariff rider, as the Company, not its customers, manage the DSM program expenditures. In other words, if the DSM program expenditures exceed tariff rider collections in the future, the Company may not collect interest on the negative balance.

**D.	<u>PROFORMA DEPRECIATION (ELECTRIC AND GAS)</u>**

On April 27, 2000 the Company submitted a revised Ex. 291, page 1-11, recalculating the depreciation rates and effects on the depreciation adjustment based on the parameters in Ex. 614. Staff and the Company are in agreement with the revised exhibit and recommend that the depreciation parameters shown in Ex. 614 be approved effective January 1, 2000.

VII. COMMISSION STAFF RECOMMENDS THAT THE FAIR OVERALL RATE OF RETURN FOR AVISTA UTILITIES BE SET AT NO MORE THAN 8.64%

A. INTRODUCTION AND OVERVIEW

1. Recommendations of the Parties

The Company, Commission Staff, and Public Counsel each presented evidence to the Commission on the issue of the fair rate of return for Avista Utilities. These parties computed their recommended overall rates of return as follows:

Type of	Capital Ratios (%)			Cost Rates (%)			Weighted Cost (%)		
Capital	Avista	Staff	P.C.	Avista	Staff	P.C.	Avista	Staff	P.C.
Long-term debt	47.0	40.0	46.03	7.83	7.44	7.45	3.68	2.98	3.43
Short-term debt	-	8.5	4.55	-	6.00	6.67	-	0.51	0.30
Preferred stock	6.0	9.5	10.45	8.14	8.22	8.12	0.49	0.78	0.85
Common equity	47.0	42.0	38.97	12.25	10.40	10.88	5.76	4.37	4.24
Total	100.0	100.0	100.0					9.93	8.64
8.82									

It is obvious from an examination of the table above that the differences in the overall rates of return recommended by the parties relate primarily to differences in their capital structures and costs of common equity, and secondarily to differences in the cost of long-term debt.

2. The Commission Should Determine the Appropriate Capital Structure and Rate of Return for the Regulated Gas and Electric Operations of Avista Utilities, Not for Avista Corporation as a Whole

Consumers in the State of Washington are required to pay just and reasonable rates that reflect a just and reasonable return on equity and a just and reasonable capital structure. A just and reasonable return on equity is one which allows investors to earn the return they require to invest in the common stock of Avista Utilities were it traded, not in Avista Corporation, which is far riskier. The evidence of record and financial markets tell us that a 10.4% return on equity meets this requirement.

A just and reasonable capital structure is one that is both safe and economical. The evidence in this case clearly shows that a capital structure containing no more than 42.0% common equity capital is eminently safe and obviously more economical than the Company's proposed capital structure. Therefore, all competent evidence put before the Commission related to cost of equity and capital structure shows that it should set rates based on an 8.64% overall rate of return. No more is needed by Avista Utilities and no more should be allowed.

During the hearings, numerous questions were asked of all the cost of capital witnesses about determining the capital structure of the Company's overall operations, as opposed to the capital structure of the utility. In their testimony, each of the experts, Dr. Avera, Dr. Lurito, and Mr. Hill, used a proxy group of companies to estimate the proper capital structure for Avista's regulated operations. For example, during the first round of cross-examination, Dr. Avera testified that he separated out the utility operations of Avista (TR 664-665; See also TR 669, lines 4-14). During the second phase of cross-examination (TR 1833; page 1837, line 24, through page 1838, line 3), Dr. Avera criticized Dr. Lurito for stating that he attempted to find relatively "pure play" utilities (i.e., those that had a small proportion of unregulated operations), despite the fact that that is precisely what Dr. Avera said he attempted to do (TR 1832). On cross-examination, at TR 704, lines 16-25, he testified:

> So, instead of looking at other companies that are well along the path of diversifying, we tried to pick a group of utilities that are still in the relatively pure play state, where the predominant part of their business is electric and gas service. So we try to look at a sector of the industry that still is relatively pure and use that as the benchmark for the cost of equity, and ultimately, the cost of capital to the pure utility part of Avista's operations in Washington.

See also TR 717, lines 17-25.

Avista Corporation's unregulated operations accounted for 86% of the Company's total revenues in 1999 (Ex. 400, pages 2, 23; See also Ex. 632, page 16, lines 4-5). From the same source, it can be seen that the Operating Income figure for Avista Utilities is positive (i.e., there was income) while the same figures for Avista's nonregulated operations show losses for 1999. Therefore, although the amount of money flowing through the Company is largely driven by the Company's unregulated operations, the profits for 1999 are driven solely by the Company's utility operations. To set rates for the customers of the regulated utility using the capital structure of the Company as a whole would burden the utility customers with a more risky, and more costly, cost of capital than would be fair, just, and reasonable. As Dr. Lurito testified:

> It's been a sound regulatory principle, at least as long as I've been in this area, that each bucket stands on its own bottom, and what that means is that if I were a commissioner, when I analyze a regulated operation, I must put blinders on and ask myself the following question: What are the risks of this regulated operation? Forget about whatever the company might be doing. They might be doing some very risky things, and that leads to uncertainties of all of those things. There is no question about that, but the issue before us or me, I think, is what is a

> fair and reasonable return? What is a fair and reasonable capital structure for the regulated operations of this company?

TR page 1795, line 17, through page 1796, line 5. On redirect examination, Dr. Lurito stated:

> That goes back to the issue that it's only fair that ratepayers pay for the risks that is (sic) inherent in providing them service, not the risks of some other group of customers consuming an entirely different product. Those people should bear the risks and the prices they pay.

TR page 1820, lines 6-11.

B. THE CAPITAL STRUCTURE RECOMMENDED BY DR. LURITO IS THE MOST APPROPRIATE CAPITAL STRUCTURE TO USE IN SETTING AVISTA'S RATES

It is a long-standing principle of sound ratemaking that a utility is entitled to earn a return on capital sufficient to preserve its creditworthiness and sufficient to permit it to sell additional debt and equity capital on reasonable terms. However, sound ratemaking also demands that the rate of return on capital must not burden ratepayers unnecessarily, i.e., it must be economical. Therefore, a necessary ingredient in meeting these twin objectives is that the capital structure used to set rates must be shown to be both safe for the company and economical for consumers.

Dr. Lurito carefully demonstrated that the capital structure he recommended meets this critical safety/economy standard. He showed that his capital structure and related overall rate of return recommendation produced a 3.27x pre-tax coverage of Avista's total interest. This 3.27x coverage is at the upper end of the 2.5x to 3.4x Standard & Poor's (S&P) guideline necessary to achieve a BBB to A rating (Ex. T-632, page 28). Avista Corporation's debt is rated BBB+ by S&P and A3 by Moody's (Ex. 634, Schedule 1). Dr. Lurito also showed that his recommended capital structure and overall rate of return will produce a funds-from-operations interest coverage of 4.6x and a funds-from-operations-to-total-debt ratio of 28.2%. (Ibid., pages 28-29). Only a 3.8x funds from operations coverage is needed for an A rating and just a 25.3% funds-from-operations-to-total-debt ratio is needed for an A rating according to S&P's guidelines. Dr. Lurito has shown that his recommendations will protect Avista's creditworthiness, permit it to access capital markets on reasonable terms, and achieve (maintain) an A rating. Avista Utilities is not a high-risk company. As Dr. Lurito testified:

> Avista Utilities is largely, largely, untouched by many things that are going on around the country with respect to risks, and I'm saying to you that in my judgment, the companies I have chosen are of comparable risk, and Avista Utilities itself is not a high-risk utility in the United States, given the changes that we've seen, but I agree; you cannot take this in total isolation of everything else, because the world in which we live is changing and it's complex.

TR page 1798, lines 13-22. Mr. Matthews, in his conference call with the investor community on June 21, 2000, several times made the point that Avista Utilities is not subject to an environment of restructuring or an imminent move to a competitive environment. See Ex. 17, pages 6, 57; TR page 2010, line 15, through page 2012, line 7.

The company's proposed capital structure containing 47.0% common equity capital is not only hypothetical but also an incorrectly computed hypothetical (Ex. T-622, Testimony of Stephen Hill, page 14). It is hypothetical because it is based on the average capital structure for the group of 12 combination electric/gas companies Dr. Avera selected for study at year-end 1998 (Ex. T-101, page 26). It is incorrectly computed because it fails to include the reality that Avista consistently uses short-term debt to finance its operations (Ex. T-622, pages 15-16). Both Dr. Lurito and Mr. Hill recommend that short-term debt be included in the capital structure used to set rates in this case (Ex. 634, Schedule 8, Revised June 28, 2000 and Ex. 627, Schedule 12).

Mr. Hill showed that if Dr. Avera had reflected the reality of short-term debt in his recommended capital structure, the most recent capital structure for his group of 12 electric/gas utilities contains an average of 43.2% common equity (Ex. T-622, page 15, lines 3-10). This 43.2% common equity ratio is virtually identical to the 43.4% common equity ratio that Dr. Lurito testified was the average at year-end 1999 for his group of five comparable-risk utilities (Ex. T-632, page 27).

Finally, it should be noted that at year-end 1999 Avista Corporation's actual capital structure contained 43.2% common equity, considering its then-outstanding convertible preferred stock as common equity (Ex. T-632, page 26). (At present, all of this convertible preferred stock has been converted; TR 1789-90). Dr. Lurito recommended that rates be based on a 42.0% common equity ratio which is: (a) slightly lower than Avista Corporation's actual year-end capital structure, (b) slightly lower than the properly computed equity ratio for Dr. Avera's group of companies, and (c) slightly lower than the equity ratio for his own group. Most importantly, Dr. Lurito recommended a capital structure containing 42% common equity because it is safe and economical (Ex. T-632, pages 27-30) and because it reflects the reality that the operations of Avista Utilities are less risky than those of Avista Corporation as a whole (Ex. T-632, page 28).

In his testimony before the Idaho Public Utilities Commission in Case No. WWP-E-98-11, Dr. Avera testified that a 37.42% common equity ratio was reasonable for Avista Utilities and that a 3.01x before-tax interest coverage was reasonable to use to set rates (Ex. T-632, page 29; See also Ex. 119, Direct Testimony of William Avera in Idaho PUC case No. WWP-E-98-11, page 65). Therefore, Dr. Lurito's 42% common equity of ratio recommendation is more favorable to the Company than what Dr. Avera testified to in Idaho. Moreover, Dr. Lurito's recommended 3.27x pre-tax interest coverage is also more favorable to Avista than what Dr. Avera recommended in Idaho.

In this regard it should be noted that Mr. Hill's recommended common equity ratio of 38.97% is well in line with what Dr. Avera recommended in Idaho. Furthermore, Mr. Hill's recommended pre-tax coverage of 3.0x is also virtually the same as the 3.01x Dr. Avera found appropriate in Idaho. The fact is that Dr. Lurito's recommended common equity ratio is higher than either Dr. Avera's or Mr. Hill's as are the measures of financial integrity implicit in his overall rate of return recommendation.

In sum, the Company has presented no sound rationale for its recommended hypothetical capital structure. In fact, it contains far more common equity than Avista Corporation found appropriate to have at year-end 1999 to finance its <u>risky</u>, <u>unregulated</u> operations which account for some 86% of its total revenues (Ex. 634, page 11). Ratepayers should not be asked to pay in rates for a capital structure that is far more expensive than what Avista itself apparently believes its customers in its competitive markets should pay. The Commission must send a strong signal to Avista that is does not intend to force ratepayers to subsidize its non-regulated operations. Dr. Lurito's recommended capital structure is as far as the Commission needs to go in balancing the objectives of safety and economy.

C. <u>COST OF DEBT</u>

1. The Cost of Debt Used to Set Rates in this Case Should Be the Most Current, Reliable Estimates of the Company's Costs

In his prefiled testimony, Dr. Avera computed the cost of long-term debt at June 30 1999 to be 7.968%. In response to data requests, he recomputed that cost rate at March 31, 2000 to be

7.308% (Ex. 149). Dr. Lurito testified that his original and his revised testimony used the cost of long-term debt developed by Dr. Avera.

However, Dr. Lurito testified that Dr. Avera's 7.308% cost rate for long-term debt ignores the fact that $110 million of preferred trust securities should be treated as long-term debt. When that reality is taken into consideration, that cost rate becomes 7.44% (Ex. T-632, page 5 revised June 28, 2000). Mr. Hill recommended a 7.45% cost rate (Ex. 627, Schedule 12), virtually the same at Dr. Lurito's 7.44%. Because ratepayers should only pay in rates for the cost rate of long-term debt that will exist while rates are in effect, the Commission must reject the Company's proposed 7.83% cost of long-term debt (computed as of June 30, 1999, over one year ago) in favor of the more recent cost rate recommended by Dr. Lurito.

Dr. Lurito's revised testimony used the Company's cost rates as of March 31, 2000 because, in setting rates to be applied in the future, the goal is to use those cost rates that are reliable and closest in time to when the rates will go into effect. The cost of debt information, updated to March 31, 2000, caused Dr. Lurito's cost of long-term debt to decrease from 7.83% to 7.44%.

The same principle of applying the most recent cost rates for debt applies to the Company's short-term debt. The updates provided by Dr. Avera in Ex. 149 caused Dr. Lurito to increase his cost of short-term debt 5.74% to 6%. Dr. Lurito testified that he did not use the precise rate of 6.98%, the cost of short-term debt at March 31, 2000, because it appears to be a temporary spike in those rates. Mr. Eliasson's Ex. 521, page 3, lists the monthly cost of short-term debt incurred by the Company from January 1999 to May 2000, which never rises to the

7.0% rate that Mr. Eliasson used in his testimony (Ex. 520, page 9, lines 7-8). The average monthly cost of short-term debt over that time period was 5.79% (TR page 1862, lines 22-25). It should be noted that the cost of short-term debt at March 31, 2000 was only .33% less than the cost of long-term debt. As Dr. Lurito testified (TR page 1816, line 21, through page 1817, line 17) , it is unlikely that this situation will endure for an extended period of time.

D. <u>COST OF COMMON EQUITY CAPITAL</u>

1. General Principles

While the determination of the cost of common equity capital requires the exercise of judgment, the use of judgment must be circumscribed by the facts. If meeting the burden of proof through opinion testimony has any meaning, it means that the witness must present a logical nexus between the factual evidence presented and the opinion offered. As will be shown, Dr. Avera's opinions fail to meet this criterion; Dr. Lurito's do.

In determining the cost of equity capital, both Dr. Avera and Dr. Lurito relied on the discounted cash flow (DCF) method. Dr. Avera also made a cost of equity estimate based on various equity risk premium studies. The Commission must consider each witness' presentation and determine first whether there is a logical nexus between the evidence presented and the opinion offered and, second, whether given that nexus, the opinion is reasonable.

2. The Presentation of the Company – Dr. William Avera

Dr. Avera selected 12 combination electric/gas utilities for analysis. In order to perform a multi-stage DCF analysis, he had to make several critical assumptions, the most important of which are:

1. All of the 12 will have a fully deregulated, fully competitive generation segment by 2008.

2. All 12 utilities will have 50% of their investment in generation and 50% in transmission/distribution.

3. All of these generation segments will enjoy a 10.4% per year earnings per share (EPS) growth forever beyond 2008.

4. All of the 12 utilities will enjoy a 7% per year EPS growth forever beyond 2008 on a total-company basis (generation plus distribution/transmission).

5. All of these utilities' generation segments will account for 50% of total assets.

6. All of these 12 companies will have a 60% payout ratio forever beyond 2008 (Ex. T-632, pages 34-35).

These assumptions, among others, led Dr. Avera to conclude that the cost of equity based on his DCF approach is 10.9% to 11.9% (Ex. T-101, page B-7).

Dr. Lurito showed that each of these six assumptions is insupportable. For example, in order that all of the 12 utilities enjoy a 10.4% growth in EPS forever beyond 2008 in their generation segments and in order for all of them to have a 60% payout ratio, every one of these utilities must earn a whopping 17.5% on common equity capital forever beyond 2008 on a total company basis. In addition to this, they must earn a 20% + return on equity (ROE) forever beyond 2008 on their generation assets (Ex. T-632, page 35). Dr. Lurito testified that over the last 25 years the average ROE for all manufacturing corporations in the United States was only 12.8% (Id.). Dr. Avera's assumption of a perpetual 20% + ROE for generation assets is totally unsupportable.

Dr. Avera's sole source for the 60% payout ratio that he says every one of his 12 utilities will adopt in 2008 and beyond is a person named Leonard Hyman who wrote an article entitled

"Fearless Forecast: Electric Utilities in 2007" (Ex. T-101, page B-6). There is no evidence any of the managements of the 12 utilities Dr. Avera studied even read that article, let alone adopted it as corporate policy.

Dr. Avera's assumption that <u>all</u> of his 12 electric/gas distributors will enjoy a 7% EPS growth on a total company basis forever beyond 2008 is itself based on even more untenable assumptions. The first assumption that it rests on is that investors believe that generating assets will account for at least one-half of electric utilities' total assets (Ex. T-101, page B-5). Dr. Avera admitted that he has made no study of investors' beliefs in this regard (TR page 693). Rather, Dr. Avera simply relied on two studies that commented on this issue. While one of the authors indicated that generation accounts for about 59% of the book value of IOU assets, the other said it was about 50%; Dr. Avera chose to rely on the 50% figure. He never studied what investors really believe.

The second and most significant assumption underlying the 7% earnings per share growth rate is the assumption that the competitive generation segment of each of the 12 utilities, starting in 2008, will enjoy forever the average of the earnings per share growth projected by IBES and Value Line for the S&P 500 companies and the Industrial Composite group of 875 companies <u>over the next five years</u>. In other words, IBES and Value Line each projected the growth rates for the S&P 500 companies, and the Industrial Composite group of companies, for the next five years. Dr. Avera took those two projected growth rates of 13.3% and 7.5%, respectively, and averaged them to obtain an average growth rate of 10.4% (Ex. T-101, page B-4, TR pages 698, line 25, through page 701, line 17). It is well known that our economy is still in a very rapid growth mode with rapid earnings per share increases. There is no basis whatsoever for the assumption that Dr. Avera is making that this rapid growth rate will continue forever beyond 2008.

If Dr. Avera had used the lower end of the 7.5% to 13.3% range, his long-term earnings per share growth rate would have been 5.5%, not 7%. Dr. Lurito proved that had Dr. Avera used a 5.5% earnings per share growth rate beyond 2008 for his 12 utilities, his average cost of equity result would have been 10.2% which is right in line with Dr. Lurito's 10.15% DCF result (Ex. T-632, page 24). It is interesting to note that if Dr. Avera had used the 7.5% long-run historical growth rate in earnings per share for the S&P 500 group of companies as the proxy for the generation segment's growth rate, his DCF results would also have been in line with Dr. Lurito's findings (Ex. T-632, pages 36-7).

The final assumption Dr. Avera made to arrive at the 7% earnings per share growth rate is that the average of S&P's 13.5% and Value Lines' 7.5%, (the average being 10.4%), somehow produces the right answer. As Dr. Lurito noted, the averaging of two numbers that purport to measure the same thing, which are 77% apart, is a very suspect procedure (Ibid., page 38).

As mentioned, Dr. Avera assumed that all of his 12 utilities will have a 60% payout ratio by 2008. In order for this assumption to come to reality, six of these 12 utilities would have to radically change their current payout ratio policy. Indeed, three of Dr. Avera's 12 companies, Alliant Energy, Puget, and Sempra, currently have payout ratios of 85% or more. (Ibid., page 26). For these companies to lower their payout ratios to 60% by 2008 would require that they radically cut dividends. This is simply not going to happen.

As Dr. Lurito testified regarding Dr. Avera's myriad assumptions:

> . . . Dr. Avera chooses to apply a multi-stage DCF model that demands that he guess what investors are expecting by way of earnings per share growth beyond 2008 in both the regulated and unregulated segments of the utilities he selected for analysis. To make that guess he had to make a myriad of critical assumptions most of which, as shown, are insupportable. More supportable assumptions produce cost of equity estimates in line with the results of my DCF study.
>
> Finally, it should be noted that even Dr. Avera allowed that his multi-stage DCF model is based on a number of assumptions regarding investor expectations and beliefs, and changing any one of them will impact his estimates of the cost of equity capital (Ex. T-101, page B-7). I certainly agree with that (Ex. T-632, page 39).

Dr. Avera's application of a multi-stage DCF model produced a 10.9% to 11.9% cost of equity estimate. This estimate is not only based on unsupportable assumptions, but it is contradicted by current market evidence. Specifically, Dr. Avera's 12 gas utilities enjoyed a 13.9% ROE in 1999. The group's payout ratio was 72%. At March 31, 2000 the group of 12 had a whopping 1.53 market-to-book ratio (Ex. T-632, page 39). Dr. Lurito proved <u>based on the very DCF theory Dr. Avera espouses</u>, that these financial realities demonstrate that the cost of equity for Dr. Avera's group of 12 is only 10.4%, not 10.9% to 11.9% (<u>Ibid</u>., page 40). Dr. Lurito's proof is not based on guesswork, it is based on marketplace facts. Dr. Avera provided no rebuttal of this proof.

As mentioned earlier, Dr. Avera also sought to estimate the cost of equity by reliance on several equity risk premium studies done by others. The first two studies he relied on were done by Carleton, Chambers, and Lakonishok (CC&L) and covered the 1971-1980 and 1972-1980 periods (Ex. T-101, page C-6). These authors applied a mechanistic DCF approach to measure the cost of equity in that they relied on the 10-year historical growth in dividends per share as the estimate of future dividend growth. Dr. Avera reported that the two equity risk premiums found by CC&L in today's terms are 5.32% and 4.30% (Ibid., page C-14). Curiously, Dr. Avera saw fit not to rely on the same mechanistic DCF approach that CC&L took for purposes of his DCF study in this case. Dr. Lurito testified that if Dr. Avera had relied on such an approach, his cost of equity estimate would have been only 6.7% (Ex. T-632, page 41).

Moreover, the 1971-1980 and 1972-1980 periods are so old and so short that any risk premium based on them are dubious at best. To see that this is the case, it is only necessary to refer to another of Dr. Avera's risk premium studies. On Table 3 of Appendix C (Ex. 102), Dr. Avera sets out a risk premium study over the 1945-1998 period, where the risk premium is based on the difference between the realized rates of return for the S&P electric group and the realized returns on A-rated public utility bonds. Over the very same periods that CC&L studied, that is, the 1971-1980 and 1972-1980 periods, Dr. Avera's study on Table 3 produces a negative equity risk premium. As seen, CC&L's studies produced positive risk premiums of 4.30% and 5.32%. The Commission is left to decide whether the CC&L studies or the realized rate of return study should be ignored, or both.

Dr. Avera then presented equity risk premiums based on studies done by another group of authors. These three authors, Brigham, Shome, and Vinson (BS&V), published equity risk premium studies covering the 1966-1984 and the 1980-1984 periods. These authors also relied on a mechanistic DCF model in which the future dividend growth was estimated using security analyst forecasts for the electrics in the Dow Jones Utility Average (Ex. T-101, page C-8). These studies produced equity risk premiums in today's terms of 3.79% and 6.97%. The Commission must reject the 6.97% risk premium out-of-hand because it is based on just five years of data. Next, it should be noted that even though both of these estimates have been corrected by Dr. Avera to apply to today's economic environment, they are <u>84%</u> apart. This does not inspire confidence in either estimate. Over the 1966-1984 period, Dr. Avera's realized rate of return study produced an equity risk premium of 1.36%. As seen, BS&V found a 3.79% risk premium for the same period. Since Dr. Avera apparently believes that the 3.79% equity risk premium is a valid estimate based on the BS&V study, it would seem only fair to conclude that the 1.36% equity risk premium over the 1966-1984 period from his Appendix C, Table 3, study is equally valid. Use of the 1.36% equity risk premium produces a 9.23% cost of equity on Dr. Avera's own ground (7.87% + 1.36%). The average of the two risk premiums is 2.58% and produces a 10.44% cost of equity estimate. This estimate is very close to the 10.15% cost of equity that Dr. Lurito found appropriate. Finally, Dr. Lurito noted that Dr. Avera chose not to apply the BS&V mechanistic DCF approach to cost of equity capital in his own DCF study. Despite this fact, he chose to rely on the equity risk premium produced by this very same mechanistic approach (Ex. T-632, page 42).

The next study Dr. Avera relied on was a survey of institutional investors made by Charles Benore. Mr. Benore asked these investors what equity premium over AA rated utility bonds they required to be willing to invest in the common stock of electric utilities. This study, which covered an 11-year period from 1975 through 1985, produced a 5.00% equity risk premium adjusted to the current market environment (Ex. T-101, page C-11). The Commission should note that the Benore study was conducted during a hyper-inflationary period when electric utilities were heavily involved in risky nuclear plant construction. The inflation rate today is in the 3.0% area; it averaged 7.2% per year over the 1975-1985 period. Needless to say, Avista Utilities is not building nuclear plants. Dr. Avera's Ex. 102, Appendix C, Table 3, study produces a 7.77% equity risk premium over the same 1975-1985 period. The 7.77% risk premium is 55% more than Mr. Benore's over the same period of time. This shows what a biased period of time Mr. Benore studied; it also shows how volatile the equity risk premium is as between studies and it shows why Mr. Benore's 5.00% equity risk premium should be rejected.

Dr. Avera's next equity risk premium study was based on authorized returns on equity for electric utilities and utility bond yields over the 1974-1998 period (Ex. 102, Appendix C, Table 2). This study indicated that the equity risk premium over the 1974-1998 period is 3.04% which, when adjusted to current interest rates, produces a 4.12% risk premium. Dr. Lurito noted that public utility commissions typically include in their allowed returns on equity a markup above the investors' required rate of return on equity (cost of equity). This markup is designed to permit the utility to recover sunk common stock financing costs as well as to permit protection against market pressure and market drop phenomena. Indeed, in this rate case both Dr. Avera and Dr. Lurito recommend a 25 basis point markup above the cost of equity to allow for the recovery of sunk financing costs alone.

This Commission is aware of the fact that in the past at least another 25 to 50 basis points were added to the cost of equity to account for market pressure and market drop risks. Hence, it is reasonable to posit that the 3.04% equity risk premium Dr. Avera found in his allowed ROE study overstates the true risk premium by 50 to 75 basis points. Hence, the risk premium based on allowed rates of return is likely to be in the 2.29% to 2.54% area (3.04% - .25% to .50%). When this equity risk premium range is marked up by 1.08% to account for the interest rate change, the result is 3.37% to 3.62%. When this equity risk premium range is added to the 7.87% bond yield that Dr. Avera used, an 11.24% to 11.49% cost of equity is produced.

Dr. Lurito indicated that such a cost of equity still overstates the true cost of equity. He testified that the study he made which compares the market-to-book ratio to the earned and allowed rates of return for the group of five utilities he analyzed, showed that just an 11.3% ROE last year generated a 1.15 market to book ratio at March 31, 2000 (Ex. T-632, page 44). This is <u>direct</u> <u>market</u> evidence that even an 11.24% to 11.49% cost of equity is too high. If the cost of equity were 11.24% to 11.49%, then the book-to-book ratio should be only 1.0. That it is 1.15 shows, based on <u>market</u> <u>evidence</u>, that the cost of equity is in fact well below that range. The 11.99% cost of equity (7.87% + 4.12%) based on Dr. Avera's study of allowed ROE is even farther out of line with current market realities.

Dr. Avera then performed two equity risk premium studies based on historical realized rates of return on stocks and bonds. The first study he made was based on the historical realized rates of return for the S&P 500 and for a selected group of "small company" stocks. Over the 1926-1998 period the realized rates of return on these groups of stocks were 5.9% and 7.5%, respectively, above the realized rate of return on long-term government bonds. The average spread is 6.7% and was relied on by Dr. Avera. Under CAPM theory, if this risk premium is multiplied by the beta ratio for the stock or group of stocks being studied, an equity risk premium for the stock or group of stocks is produced. In the case at hand, the beta for Dr. Avera's group of 12 utilities is .54. Hence, the risk premium for that group is 3.62% (6.7% x .54). Dr. Avera then added this 3.62% risk premium to the long-term government bond yield of 6.42% that prevailed in September 1999. This produced a cost of equity of 10.04% (Ex. T-101, page C-13). The equity risk premium related to A rated utility bonds was only 2.11% (10.04% - 7.93%).

In commendable candor, Dr. Lurito pointed out that while the 2.11% equity risk premium and the 10.04% cost of equity consistent with it supports the results of his DCF analysis, he placed little confidence in it. Dr. Lurito testified that the analyst can manipulate the results of such equity risk premium studies simply by choosing different time periods. This is precisely the problem with Dr. Avera's second equity risk premium study based on historical realized rates of return on electric utility common stock (Ex. T-632, page 45).

Dr. Avera, in his second study, computed the arithmetic mean and geometric mean realized rate of return for the group of electric utilities included in the S&P 500 composite group over the 1946-1998 period. Those two statistics were 10.99% and 9.94% (Ex. 101, Appendix C, Table 3). Dr. Avera then computed the arithmetic and geometric mean realized rate of return on A rated public utility bonds over the same period. This produced means of 6.29% and 5.91%. Subtracting the average return on electric utility stocks from the bond rate of return produced a 4.37% equity risk premium. Dr. Avera did not make any adjustments to the 4.37% to account for interest rate changes.

To show how unreliable this 4.37% equity risk premium estimate is, Dr. Lurito performed a study identical in methodology to Dr. Avera's, except Dr. Lurito chose to analyze the 1960-

1998 period, instead of the 1946-1998 period that Dr. Avera relied on. Dr. Lurito's study produced a 2.41% equity risk premium which, when added to Dr. Avera's 7.93% A rated bond yield, produces a 10.34% cost of equity capital. Again, while this result certainly supports Dr. Lurito's DCF cost of equity finding and contradicts Dr. Avera's, little comfort should be taken from that reality. Dr. Lurito testified that this is the case because equity risk premiums based on historical realized rates of return are inherently unstable as they change radically as the period of time analyzed changes (Ex. T-632, page 46).

Dr. Avera concluded, based on the many equity risk premium studies he relied on and performed, that the cost of equity for Avista Utilities is in the 11.9% to 12.9% range (Ex. T-101, page 53). Dr. Lurito summarized the many flaws in Dr. Avera's studies, which disqualify this cost of equity estimate, as follows:

1. Some studies he relied on covered too short a time period to have any credibility.

2. Some studies were based on mechanistic applications of the DCF model that Dr. Avera himself chose not to rely on in this case; therefore, the risk premiums from such studies can be given little weight.

3. Some studies produced radically different equity risk premium results depending on the time period selected.

4. Some studies were made over an anomalous period of economic history that has no relationship to today's environment.

5. The equity risk premium results over the same time period varied markedly from study to study.

Dr. Lurito was then asked why he didn't perform an equity risk premium study. He stated:

> I could have chosen long time periods which produce equity risk premiums and costs of equity estimates that appear to support the results of my DCF study. To have done so would simply have been disingenuous because, in my opinion, this approach to the cost of equity is fundamentally flawed (Ex. T-632, pages 46-47).

Based on the evidence of record, the Commission must agree with Dr. Lurito's conclusions in this regard.

3. The Presentation of Staff – Dr. Richard Lurito

Because of all of the unsupportable assumptions Dr. Avera had to make in order to implement his multi-stage DCF approach, Dr. Lurito chose to select companies that are amenable to the application of a traditional, constant growth DCF model. His testimony on this issue is critical; he stated:

> Prior to the start of the "new era" in the electric/gas utility industry, most companies displayed reasonably low and stable historical dividends, earnings and book value per share growth rates. This permitted investors to reasonably anticipate that these trends would continue into the long-run future. . . . the advent of the problems many utilities faced with nuclear generating plants and, especially, the advent of industry restructuring merger/acquisition activity and the introduction of competition at both the wholesale and retail level of the electric/gas industry, created serious problems concerning how investor expectations as to future dividend growth could be measured. Multi-stage DCF models were introduced in an attempt to recognize that many utilities' future dividend growth experience would likely diverge from past experience. However, it is crucial to note that the mere introduction of a multi-stage DCF model doesn't ipso facto solve the problem of cost of equity estimation because it has nothing to do with making the task of accurately estimating investors' future dividend growth expectations any easier. In my opinion, the answer to the current cost of equity estimation problem is not to guess about future growth expectations but rather to avoid having to guess. As will be discussed in greater detail later in this testimony, in my opinion Dr. Avera chooses to guess; I choose to avoid having to guess. . . . the analyst can avoid having to guess by selecting electric and electric/gas utilities that have sufficiently stable pasts and futures so as to permit the analyst within the context of a single-stage DCF approach to make reliable cost of equity estimates. This is precisely what

the selection process I propose to use in this case is designed to accomplish
(Ex. T-632, pages 17-18).

To further his goal of selecting utilities with stable pasts and stable futures, Dr. Lurito applied six criteria to all electric and combination electric/gas utilities:

1. The company's dividend payout ratio was 70% to 90% in 1999.

2. The company's current dividend yield is in excess of 7.0%.

3. The company did not cut its dividend over the 1989-1999 period.

4. The company is not currently in a merger/acquisition mode.

5. The company has not been involved in a significant merger/acquisition for at least 10 years.

6. The company's non-regulated business revenues in 1999 account for about 30% of total revenues or less.

This selection process produced a group of five companies. Dr. Lurito then computed the average dividend yield for the group for the six month period ended March 2000; this yield was 7.43% (Ex. T-632, page 18). He then analyzed historical and future growth rates in dividends per share, earnings per share, book value per share, and the growth from retained earnings (Ex. 634, Schedules 4-6). Based on this analysis, Dr. Lurito opined that rational investors are expecting a long-term growth in dividends per share of 2.5% to 2.7% (Ibid., page 21). He then marked up the dividend yield for one-half year's growth to arrive at a 10.02% to 10.23% cost of equity; the average of these is about 10.15%. Dr. Lurito marked up this 10.15% cost of equity by 25 basis points to allow Avista to recover past common equity issuance expenses; hence, he arrived at a 10.4% cost of equity (Ibid., page 25).

Unlike Dr. Avera, Dr. Lurito showed, based on current market evidence, that his 10.15% bare cost of equity finding is accurate. He did this by noting that in 1999 his group of five utilities earned 11.3% on common equity; it has a 2.6% dividend growth expectation, it had a 76.99% payout ratio in 1999, and it has a 1.15 market-to-book ratio currently. He then proved using DCF equations that the market is telling us that the cost of equity is 10.17% (Ibid., page 22). This is virtually the same as his 10.15% cost of equity based on his application of the traditional DCF approach.

4. Cost of Common Equity – Summary

The Commission must adopt the cost of equity presented by that witness who shows a clear path between theoretical results and market realities. Dr. Lurito meets this test; Dr. Avera does not because his cost of equity result is not only theoretically flawed due to the many unsupportable assumptions he made, but also because market evidence tells us his 12.00% return on equity recommendation is too high.

E. THE COMPANY'S REQUEST FOR AN UPWARD ADJUSTMENT TO ITS RETURN ON EQUITY, OR EQUITY "KICKER" OF 25 BASIS POINTS SHOULD BE REJECTED

In Mr. Dukich's testimony, he recites a variety of reasons why the Commission should reward the Company with a higher ROE. That testimony can be summarized as statements that the Company's accomplishments in several areas have been recognized by others, so the Commission should provide the Company some recognition of good management practices by increasing the rate of ROE that the Company is allowed to earn.

As noted by Chairwoman Showalter (TR page 370), if 25 basis points are added to the Company's authorized ROE, that additional return is embedded in rates until such time as the Company may choose to file another rate case.

The increased expense of a higher ROE is borne by the ratepayers, with no showing of the benefits they receive from the higher rate of return. Avista's traditionally low rates for power are largely attributable not to the efforts of current management, but those of its past management and from the use of low-cost hydropower. As noted by the authors of one of the efficiency studies cited by Mr. Dukich (Ex. 47; TR page 319, lines 23-25), there is a strong correlation between the efficiency of the Company and the share of hydroelectric power in the utilities' generation mix. The fact that the founders of the Company had the foresight to locate it in an area where it could utilize significant amount of hydro-generation is not a reason to reward current management with a higher ROE. Staff is not contending that the Company has not been well-managed in the past, but the Company has not demonstrated why the current ratepayers should pay more for actions of past management. WUTC expects good management from the utilities it regulates, and such management can be adequately recognized through proper rates. As numerous witnesses noted in this case, Avista is not in a competitive environment and will not be in one for the foreseeable future. (See, e.g., TR page 392; TR page 2010, line 20-25).

Mr. Dukich testified that, although the Company has requested "recognition by the Commission of what we believe is a well-managed company" (TR page 332, lines 6-8), the Company's preferred form of recognition would be money, by allowing a higher ROE. He clarified the nature of the Company's request as follows:

> It does, but the level of money, to be honest about it, is probably less important than the fact that there's an official recognition of a difference between what we consider a well-managed company and maybe an adequately managed one. So from a Commission policy point of view, it's important, I think, that the Commission do something affirmatively maybe to recognize that, if they believe we are, in fact, well-managed. (TR page 332, lines 9-19)

On cross-examination, Mr. Dukich also conceded that an upward adjustment to the rate of ROE primarily benefits the Company's existing shareholders (TR page 335, lines 17-23). It is obvious that if a company has a higher ROE, someone must bear the increased cost of that equity. Those currently holding the Company's stock would be the primary beneficiary, at the expense of the ratepayers.

If a company is, in fact, well-managed, and the company has received recognition of various sorts for efficiency or innovative programs, the company's shareholders are already "compensated" by an increase in the companys' stock price. A well-managed company can also benefit by an increased willingness by investors to invest in the company, and by lower loan rates when the company incurs debt. In fact, the only disadvantage incurred by anyone, when an increase to the rate of ROE is authorized for a regulated company, are the company's ratepayers and, in particular, those residential customers who have no effective choice of electric or gas supplier.

Despite the awards and recognition that Mr. Dukich recites the Company has received over the past 15 years, the current management of the Company does not warrant recognition in the form of a higher allowed ROE. By Mr. Matthews' own admission, the recent losses the Company incurred in its speculative power trading operations were because management "just blew it in the utility" by not acting quickly to reverse the transactions and cover the Company's position in the market (Ex. 17, page 4).

In the time since Mr. Matthews took over as CEO of Avista on July 1, 1998, the Company's performance, in the view of stock market analysts, has declined. Avista's net income has declined from $114.8 million in 1997, to $78.1 million in 1998, to $26 million in 1999 (Ex. 400, page 23). In 1998, Avista cut its dividend to shareholders, paying a dividend of $0.31 per share through the third quarter of 1998, and reducing the dividend to $0.12 per share each quarter, beginning in the fourth quarter of 1998 (Ex. 400, page 23, fn (3)). The Company's recent performance certainly does not warrant recognition as one with superior management.

In addition, as noted by the Idaho Public Utilities Commission in their rejection of the same proposed adjustment in Avista's 1998 rate filing in Idaho, a minimum standard for management of a regulated utility is regulatory compliance (Ex. 119, Order No. 28097, Idaho PUC, Case No. WWP-E-98-11, page 24). The Company's behavior in how it handled the PGE Contract monetization in this case by not directly notifying the Commission of this transaction, by not including the transaction in its rate filing in this case, even though the transaction took place during the test year, and by not providing information relating to the transaction in response to Staff's original data requests (Ex. T-540, Testimony of Alan Buckley, page 14) is disturbing, at best. The information brought out at hearing on questioning by Mr. Van Cleeve that the transaction also involved an affiliate of Avista with no affiliate transaction filing made by the Company is also of great concern to Staff. The Company's request for an increased rate of return should be rejected.

VIII. COST OF SERVICE, RATE SPREAD, AND RATE DESIGN

A. <u>COST OF SERVICE STUDIES</u>

1. Electric Cost of Service Studies

As noted in the Joint Testimony of Messrs. Kilpatrick, Lazar, and Schoenbeck (Ex. T-675, page 2), Staff believes the methodology of the Company's electric cost of service study is acceptable and that the results of the Base Case and Scenario 3 propounded by the Company are, in general, reasonable. Staff does not fully endorse the Company's study, but has not performed an independent study. Staff recommends that the Commission specifically state in its order that it is not accepting the results of any particular cost of service study, and order that any allowed increase or decrease be spread among the classes of customers as set forth in Exhibit 660.

2. Natural Gas Cost of Service Studies

Staff, along with ICNU and Public Counsel (Ex. T-680), do not agree that the methodology or results of the Company's natural gas cost of service study are accurate, but have not prepared an alternative study. Staff has specific concerns about the Company's allocation of demonstration and selling expenses and the allocation of some of the administrative and general costs. In reaching its joint recommendation on rate spread, Staff has adjusted the allocator for demonstration and selling expenses, and used Staff's proforma results of operations rather than the Company's. Staff recommends that the Commission adopt the joint rate spread recommendation of these three parties without specifically approving the Company's cost of service study.

B. ELECTRIC RATE SPREAD

Staff Position on Electric Rate Spread is contained in Exhibit 659 (Exhibit DEK-1, sponsored by Doug Kilpatrick). Staff, Public counsel, and intervenor ICNU entered joint testimony and a joint exhibit regarding the electric rate spread in this case (Ex. 675-676). Basically, Staff agrees with the proposal of Company witness Brian Hirschkorn to spread the rate changes among the classes of customers in the proportions recommended by Mr. Hirschkorn. Staff advocates that all classes of customers shoulder some share of any allowed increase in rates, and likewise should be the beneficiary of any ordered decrease in rates.

C. ELECTRIC RATE DESIGN

Staff's position on the design of electric rates for Avista is set forth in the Testimony of Doug Kilpatrick, Ex. T-658, beginning at page 7. If, as Staff recommends, the Commission directs the Company to decrease its rate to electric customers, the energy component of existing electric rates should be reduced without changes to the basic rate cohorts or blocks, and the principles outlined in the joint rate spread testimony should be implemented.

D. GAS RATE SPREAD

Staff's position on the rate spread for natural gas rates is set out in Ex. T-680. Staff advocates that any increase in natural gas rates allowed in this proceeding should be spread equally between the customer classes, except for the customers on Schedules 131 and 148. Schedule 148 customers are served by special contracts approved by the Commission, and therefore no changes to these rates can be made except when new or revised contracts are considered. There is only one Schedule 131 customer and, therefore, excepting this schedule from rate adjustments will have minimal, if any rate spread (revenue), impact on the remaining schedules.

E. GAS RATE DESIGN

The testimony of James Russell, Ex. T-668, presents Staff's position on the design of natural gas rates. The numbers used in Ex. 669 should be revised to reflect the lower numbers for the overall gas revenue requirements reflected in Mr. Parvinen's revised testimony, Ex. T-608. Mr. Russell's rate design proposals for Schedules 101, 111, and 121 are consistent with Avista's rate design proposal for these schedules. For Schedule 131 customers, Mr. Russell proposes a four-block rate schedule so that the bill for this interruptible service is lower than the bill for service under Schedule 121, which is a firm schedule. This proposal, outlined on page 4 of Ex. T-608, provides a discount below the Schedule 121 rates of from one to seven percent, depending on consumption. Avista did not oppose the joint proposal on rate spread and, in fact, supported Mr. Russell's rate design on rebuttal.

IX. CONCLUSION

The Company has failed to support its case for an increase in its electric rates, and has not justified the full amount of its requested increase in gas rates. The request should be rejected, and the recommendations of Staff and Public Counsel adopted.

The Company's proposed rate of return on equity is excessive, its proposed hypothetical capital structure improperly ignores its use of short-term debt, and is far more rich in equity than necessary to maintain its credit ratings. Avista's recommendations for the rate of return and capital structure are not supported by the record. It is abundantly clear from the facts of this case, that the Company should not be rewarded for “superior management” by an increase in the rate of return on equity by 25 basis points. The Company’s increase in administrative and general expenses alone, over the past five years, are a strong argument against granting any such equity bonus.

The Company should not be rewarded for its questionable behavior in the handling of the buyout of the PGE capacity contract. Staff’s proposed treatment of the proceeds of the buyout not only avoids rewarding the Company for its behavior, but avoids the otherwise necessary review of the prudence of transactions such as the Rathdrum lease.

Avista’s proposed power cost adjustment (PCA) ignores the dictates of prior Commission precedent, including no explicit recommendation relating to a cost of capital reduction, which the Commission has clearly stated is an essential component of a PCA. In addition, the proposed PCA is structured in a way that the Company could benefit from higher market power costs, without actually incurring higher costs to purchase power.

Commission Staff recommends that Avista's electric revenues be reduced by $19,966,388,[21] and that Avista's gas revenues be increased by $782,000.[22]

DATED this 11th day of August, 2000.

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[21] Electric rate base of 599,332,000 times rate of return (8.64%) = $51,782,284. Net Operating Income of 64,188,000 less 51,782,284 = 12,405,716. 12,495,716 divided by conversion factor of .621330 = $19,966,388 revenue requirement reduction.

[22] Gas rate base of $119,919,000 time rate of return (8.64%) = $10,361,000. Subtract Net Operating Income of $9,875,000 = 486,000, divided by conversion factor of .621466 = $782,000 increase in revenue requirement.