BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,	)	DOCKET NO. UE-991606 and UG-991607
Complainant,	)	POST-HEARING BRIEF OF AVISTA CORPORATION
v.	)	
AVISTA CORPORATION,	)	
Respondent.	)	

Dated: August 11, 2000

AVISTA CORPORATION
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I. INTRODUCTION

On October 22, 1999, Avista Corporation (hereinafter "Avista" or "Company") filed for general rate relief with this Commission. This is the first electric general rate filing by the Company in approximately 12 years. The effect of the filing would be to increase annual revenues by $26.3 million for its electric operations and $4.9 million for its gas operations. The proposed tariff revisions were suspended, by order of this Commission, pending evidentiary hearings with regard to the reasonableness of the proposed rate request.

The Company's direct testimony was presented during the week of March 27 through March 31, 2000. Thereafter, a public hearing was held in Spokane, Washington, on April 20, 2000, for the purpose of receiving public testimony. The direct testimony of Staff and Intervenors, as well as the rebuttal testimony of the Company, was heard during the week of July 10-14, 2000.

In its filing, Staff recommended that Avista should lower its electric rates by approximately $16.5 million per year -- in contrast with the requested increase of $26.3 million proposed by the Company. As concerns natural gas, Staff proposed a revenue requirement of only $785,000 per year, as compared with the requested increase of $4.9 million. For its part, Public Counsel argues that Avista Corporation has no revenue requirement deficiency for either its Washington electric or gas operations. Its testimony suggests excess revenues of $2,058,000 for Avista's Washington regulated electric utility operations and excess revenues of $1,026,000 for the gas utility operations. (Damron, Exh. T-703, p. 2, l. 21, p. 3, l. 7).

The Industrial Customers of Northwest Utilities (ICNU) filed testimony recommending, at a minimum, a rate decrease of $2.6 million for electric operations. (Schoenbeck, Exh. T-718, p. 3, *ll*. 6-12). The Northwest Industrial Gas Users (NWIGU), for its part, concerned itself with rate spread and rate design issues with respect to the natural gas tariffs. Finally, the Spokane Neighborhood Action Programs (SNAP) sponsored testimony addressing low-income payment issues. (See Colton, Exh. T-726).

On rebuttal, the Company presented testimony challenging the positions of Staff and Intervenors in nearly every area, including cost of capital, power supply adjustments, Centralia replacement power, and relating to numerous other revenue requirements issues.[1]

II. SOUND PRINCIPLES OF RATEMAKING REQUIRE A "FAIR END RESULT"

Clearly the Company and Staff/Intervenors are at odds with respect to nearly every major issue, including power supply, determination of a reasonable rate of return, and miscellaneous accounting adjustments. Notwithstanding this "wide gulf" that separates the philosophy, approaches, analyses and conclusions of Staff/Intervenors and the Company, there should be no disagreement

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[1] After taking into account certain accepted adjustments and revisions, the Company's revised electric revenue requirement is an increase of $18,165,000 as detailed in Exhibit 269. Similarly, the revised gas revenue requirement is an increase of $4,427,000, as outlined in Exhibit 270. (See Falkner Rebuttal, Exh. T-268 at pp. 2-3).

that the "end result" from this ratemaking process must produce rates that are just and reasonable. Stated differently, the law requires that the rates received by a regulated utility for service rendered shall be "just, fair, reasonable and sufficient." (RCW 80.28.010). (See also RCW 80.28.020 "The Commission shall determine the 'just, reasonable, or sufficient rates, charges, regulations, practices or contracts to be thereafter observed . . ..") In the process, it is just as important that rates yield reasonable compensation, as it is that they shall be just, reasonable and nondiscriminatory from the standpoint of the customer. See State Ex Rel. Puget Sound Power & Light Co. v. Dept. of Public Works, 179 Wash. 461, 38 P.2d 350 (1934). While the Commission is not bound to the use of any single formula in determining rates, it is the result reached and not the method employed, which is controlling. In the process, the Commission must ensure that rates are not so unreasonably low as to constitute a taking of property without just compensation or a violation of due process by preventing the utility from earning a reasonable rate of return on its investment. The failure of a utility commission to provide rates that will give the Company a reasonable rate of return constitutes a violation of due process and a taking of property without just compensation. In the final analysis, the teachings of Hope and Bluefield still apply, in that the utility must be able to attract new capital on reasonable terms, in order to maintain, improve and expand its services. (See also Petition of PNM Gas Services v. New Mexico Public Utility Comm'n, et al., 2000 WL 554621 (N.M. 2000)).

In exercising its discretion in order to establish reasonable and sufficient rates, this Commission should also consider the impact of various proposals on the many different constituencies involved. And it is possible to harmonize the interests of all constituencies if the end result reached produces rates that are not only just and reasonable, but also sufficient to enable the Company to maintain its credit and attract new capital on reasonable terms. Who are these constituencies and how are they impacted by the various proposals in this case?

A. Impact of Proposals on Various Constituencies

In his testimony, Avista's Chairman, Mr. Matthews, addressed the issues from the perspective of the various constituencies: employees, ratepayers, communities, and shareholders.

Beginning first with Avista's employees, Mr. Matthews appropriately credits the efforts of the employees in managing costs in such a way as to avoid the need for general rate relief over the past 12 years. (Id. at p. 4, *ll*. 9-21). Since 1987, electric rates have gone up by only 3.5%, as compared with the CPI Index and COLA, which have gone up by approximately 47% during the same time period.[2] (Id.) Attached to this brief is a copy of Exhibit No. 15, showing this information graphically and superimposing the Company's request for rate relief as well as the contrary positions of Staff and Intervenors. Simply put, our employee base has worked hard to control costs, in order to avoid the need for general rate relief.[3]

Moreover, Avista's rates remain the fourth lowest in the nation; even with the full amount of rate relief of $26 million, the Company would still be in the lowest 10 out of 177 utilities surveyed. (Id. at p. 5, *ll*. 18-20).

Accomplishments of Avista, however, extend well beyond the maintenance of low rates. The Company has received national recognition in a number of other areas as well. Mr. Dukich of the Company recounted a number of achievements over recent years, including the following, among many others:

- A 1998 study by Theodore Barry & Associates in which the Company ranked number 1 out of 34 national utilities in terms of overall costs, customer service, and number 2 in terms of low cost of service when combined with overall customer satisfaction.

- The ranking of our customer call center as the number one call center in the nation in 1999.

- Our hydro relicensing efforts for the Clark Fork and Noxon hydro electric projects have won national recognition as a model for relicensing, prompting a feature story in the *New York Times* (October 10, 1999).

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[2] The 3.5% increase pertains to the implementation of a 1.5% tariff rider for DSM funding in 1995, and a rate adjustment in 1990 of approximately 2% related to a BPA power contract.

[3] While the number of customers per employee numbered 278 in 1990, by 1998 that number had increased to 390 customers per employee. (Exh. T-14 at p. 4, *ll*. 19-21).

- The Company also developed the nation's first non-bypassable distribution charge for conservation in the form of a DSM tariff rider and has pioneered DSM programs that deliver energy savings with an emphasis on participant contributions.

- The Company's Project Share fund raising campaign, which supports a community emergency heating assistance program, continues to rank in the upper tier of all utilities, in terms of funds raised per customer.

- Finally, Avista has received numerous environmental awards and is the only corporation in the state to have received four Environmental Excellent Awards from the State Ecological Commission.

(See Dukich, Exh. T-46, pp. 3-6). In Mr. Dukich's rebuttal testimony regarding the Company's request for a 25 basis point return on equity adder he explained that:

> Because of Avista's innovative approach to DSM funding, also supported by the Commission, customers are currently saving an average of $1.4 million per year or an amount in excess of the equity adder just for this one activity. (Exh. T-84, p. 18, *ll*. 9-11).

Furthermore, with regard to the Company's hydro relicensing efforts, Mr. Dukich testified that:

> "the license issued by the FERC has allowed the Company to retain the peaking and load following capabilities of the Noxon Rapids and Cabinet Gorge hydroelectric projects. As shown in Exhibit No. 88 (TDD-4), the value of just this element of relicensing translates into a savings to customers of between $4.5 to $6.5 million per year for as long as 50 years to come" (Exh. T-84, p. 18,, *ll*. 13-18).

Therefore, the innovative efforts of the Company have created annual cost savings that are far in excess of the requested equity adder.

Turning next to the impact of the message on the communities in which Avista serves, Mr. Matthews testified that the "accomplishments and future possibilities of Avista Corporation are something to cheer about." (Exh. T-14, p. 7, *ll*. 7 - p. 8, l 21). Avista is providing the "growth engine" for Eastern Washington for economic development. Avista is an active member in the community in which it serves, and is a leading promoter of charitable/civic/educational efforts. It also provides exciting employment opportunities within the utility and its various subsidiaries. Avista has also attracted national attention to the area by virtue of its many accomplishments recounted above as well as for its technology and information initiatives through Avista Labs (fuel cell technology), through Avista Advantage (internet-based bill payment and analysis program), and through Avista Communications (serving the small community CLEC business). (Id.)

Of course, within these communities are the customers that we serve. It is the Company's belief that our communities and our ratepayers understand that, after 10 years of no rate increases for electric service, there is a need for rate relief in the face of inflationary increases of approximately 47% for the same period. (Exh. T-14, p. 8, *ll*. 18-21). Indeed, at the public hearing scheduled in these proceedings, only five members of the public chose to testify against the Company's rate request, and, while this may not be a precise measure of customer opposition, it does, in the words of Mr. Matthews, "suggest that there is no public outcry against the Company's proposed rate request." (Id.)

Finally, the interests of shareholders are a vital part of the equation. Unless the Company can attract capital on reasonable terms, the other constituencies consisting of ratepayers, communities and employees, will also suffer. In that sense, the interests of all constituencies can be harmonized if rates are set at sufficient levels. It is, after all, "in the public interest" to have a strong utility that can provide safe and reliable service, doing so efficiently and cost-effectively, as testified to by Mr. Matthews. (Id. at p. 9, *ll*. 17-19). Standards and Poors recent CreditWire announcement of May 9, 2000, stated that it was revising its outlook on Avista's debt from "stable" to "negative," noting:

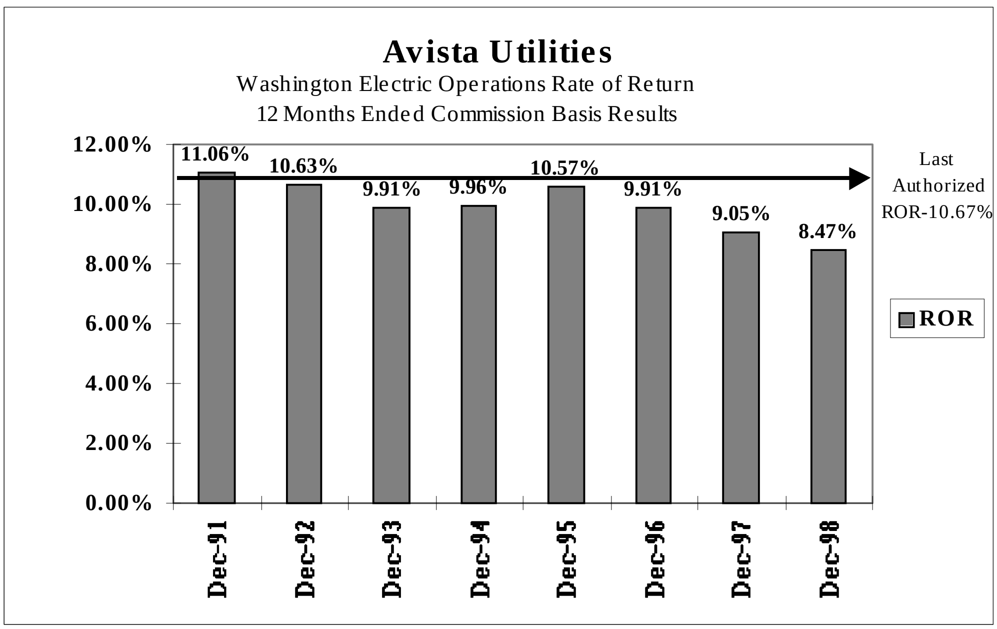
> The financial position [of Avista] may be further weakened at the regulated level if the Washington Utilities and Transportation Commission (WUTC) adopts a rate order comparable with the rate reduction recommended by its Staff in the amount of $16.5 million . . . An adverse ruling by the WUTC, in line with the Staff's recommendation, would further hamper financial performance, possibly leading to lower ratings, Standards and Poors said. (Emphasis added).

(Id. at p. 9, l 19 - p. 10, l. 8). Accordingly, even the filing of Staff and Intervenor cases advocating an extraordinary rate reduction can have an effect in the markets in which the Company must raise capital.

B. Factors Driving the Need for Rate Relief

The Company has not changed its base electric rates in Washington since 1990.[4] Since the Company last changed its general rates in Docket No. UE-900093, the Company has consistently earned below its last authorized rate of return of 10.67%. Moreover, as shown in the chart below, the Company's Washington jurisdictional rate of return has been consistently declining since 1995. When one examines the semi-annual jurisdictional electric reports filed on a "commission basis" with this Commission, one notes that electric operations have been consistently earning less than the Company's authorized rate of return for a number of years. (Id. at p. 3, *ll*. 11-23):

A number of items have contributed to the requested increase. Since 1990, average electric



customers in our Washington jurisdiction have increased from 176,700 to 201,600 — or slightly over 14% for the period 1990 through the end of 1998. During the same time period, all costs categories have increased including power supply, distribution, customer accounting and administrative and general. Depreciation rates have also been updated in this proceeding. In addition, a settlement

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[4] A Demand Side Management Tariff Rider was implemented, however, on January 1, 1995, in which a surcharge of 1.5% is being used to fund energy efficiency improvements. (Exh. T-226, p. 2, *ll*. 22-p. 3, *ll*. 2).

agreement signed in connection with the relicensing of the Company's two largest hydro-generating facilities has resulted in costs which are being proposed for recovery in this proceeding. (Id. at p. 4, *ll*. 16-p. 5, *ll*. 2).

Along with customer growth comes rate pressures. Distribution plant has increased by 47% during this same time period. Distribution plant, expressed on a per customer basis, has risen from $1,398 to $1,801 — representing a 29% increase. This results in a higher percentage of total distribution plant being comprised of newer, higher cost plant, as explained by Company witness Falkner. (Id. at p. 5, *ll*. 4-12). Moreover, distribution expenses, expressed on a per-customer basis, have also increased from $144 in 1990 to $165 in 1998, or 15%. (Id. at p. 6, *ll*. 11-14).

There is one proposition about which there should be no disagreement: i.e., that rates need to be set at levels sufficient to provide a fair return on investment dedicated to serve customers and to provide for the recovery of prudently incurred costs. The Company has presented testimony, through Mr. Falkner, that demonstrates that the test period proforma rate of return was only 7.51%. (Exh. T-226, at p. 29). This is well below a fair rate of return by anyone's measure. Mr. Matthews, in his rebuttal testimony, credits this Commission with providing strong regulatory support in the past:

> I believe it is important to have a supportive regulatory climate in all states in which the Company serves, as we approach the challenges of the next decade. The regulatory support we have had in the past has provided a good foundation to build upon. The message we need to send to the shareholders and the investment community at large is that we still have the support of our regulators as we move forward in uncertain times, and that the capital allocated to the utility business will receive fair returns. Stated differently, I believe there is a need to affirm to financial analysts that traditional rate base regulation is still supportive of our efforts.

(Exh. T-14, p. 10, l. 16 - p. 11, l. 2).[5]

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[5] The Idaho Public Utilities Commission, in a general electric rate proceeding concluding last year, awarded the Company $9.3 million of rate relief, representing almost 70% of the total request of $14.2 million. (Exh. T-14, p. 11, l. 5-12). While the Company understands that each Commission must, on its own, evaluate the Company's proposals and reach its own conclusions, the vastly different results advocated by Staff and Intervenors in these two jurisdictions is perplexing,

The following sections of this brief will address each of the issues raised by Staff and Intervenors, in turn. The discussion and debate over each issue, however, must occur in the overall "context" as discussed above. In this manner, a fair "end result" will be reached.

III. POWER SUPPLY ADJUSTMENTS

A. PGE Monetization Transaction

The Company's proposal in this case is to flow through to customers the revenue stream from the original PGE Capacity Sale Contract representing approximately $12.1 million per year for the Washington jurisdiction. Staff, however, is recommending that the $145 million up-front payment associated with this transaction be used to offset certain expense and rate-base items, as opposed to the Company's proposal to include revenue based on the revenue stream of the original contract. The proposal of Staff would, in effect, "shift" a significant amount of the otherwise levelized benefits from the later years of the PGE contract to the earlier years. (See Norwood Exh. T-203, p. 2, *ll*. 1-9). The effect of the Staff's proposal would also require an up-front write-off of $9.3 million and would otherwise reduce the Company's annual revenue requirement by approximately $11.4 million in the State of Washington. (Id., p. 2, *ll*. 27-29). For reasons that will be discussed below, Staff's proposal would substantially reduce the benefits to customers in the later years and would not appropriately match the life of the underlying contract with the associated revenue stream.

Before addressing the issues, it is, however, important to understand the original PGE Contract. As explained by Mr. Norwood in his rebuttal testimony, the original agreement dated June 26, 1992 (Exhibit No. 170) consisted of a long-term contract to sell capacity to Portland General Electric. Pursuant to that agreement, Avista sold 50 MW of capacity to PGE from November 1992 through October of 1994, and 150 MW from November 1994 through the end of the agreement — i.e., December 31, 2016. The price each year for capacity was fixed in the

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at best.

agreement, resulting in a revenue stream from this original contract for the period 1998 through 2016 in the approximate range of $18-$19 million each year. (Id. at p. 8, *ll*. 5-19).

At the same time it should be remembered that the Company placed the 176 MW Rathdrum simple-cycle combustion turbines into service in January of 1995 in order to serve the Company's system capacity needs, including the 150 MW PGE Capacity Sale. The annual costs associated with these units approximate $9 million per year. (Buckley, Exh. 545). Accordingly, if one compares the $18 million per year of revenue benefit from the PGE Contract with the $9 million per year of costs associated with the Rathdrum turbines, one can readily appreciate the "tremendous benefit" of approximately $9 million per year realized by the Company on behalf of its customers.[6]

Through the PGE monetization, the Company essentially "locked in the value of the revenue stream from the original PGE contract and secured the benefits from this contract through the year 2014," as testified to by Mr. Norwood. (Exh. T-203, p. 10, *ll*. 1-2). It was this secured or "locked in" revenue stream that the Company proposed to include for ratemaking purposes in this case. It did so for the following reasons:

(1) The primary purpose of the PGE monetization was to preserve the value of the original PGE sales contract for the benefit of customers. The receipt of these payments up front, through monetization of the contract, allowed the Company to "capture that value now" and spread it back to ratepayers over the monetization period (1999-2014); in doing so, this reduced the risk that some of the value of what was otherwise an above-market contract might be lost for the benefit of ratepayers at some point in the future, as testified to by Mr. Norwood. (Exh. T-203, p. 10, *ll*. 5-9).

(2) It should also be understood that this monetization transaction was a "financial arrangement" and, in fact, is considered a loan for tax purposes. PGE did not otherwise buy down the contract rate or otherwise buyout the contract; instead PGE continues to pay the same price per

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[6] Moreover, the 176 MW of capacity from the Rathdrum turbines provides an additional 26 MW more capacity than the 150 MW PGE capacity sale, which results in significant additional value inuring to ratepayers <u>over and above</u> the $9 million per year. (Exh. T-203, p. 9, *ll*. 1-3).

KW that was called for in the original contract. Moreover, the delivery obligations of Avista remain unchanged: Avista continues to provide 150 MW of capacity under the new monetization arrangements and will continue to do so until 2016, which is the original termination date of the contract. In this manner, the risk associated with the future revenue stream of an above-market contract was shifted away from Avista Utilities and its customers. (Id. at p. 10, *ll*. 10-18).

(3) The application filed with the Federal Energy Regulatory Commission (FERC), by the Company on September 8, 1998, for the approval of the contract assignment describes the retail ratemaking treatment and what is, in effect, "hold harmless" protection afforded to ratepayers:

> Further, both the accounting and ratemaking treatment of the proposed disposition in this Application will assure that all ratepayers, including retail ratepayers, are held harmless by the assignment. Under WWP's accounting and rate making proposal for the assignment, the benefits of the Capacity Contract will continue to be passed on to customers in such a manner that the revenue requirement reduction from the assignment proposal equals the revenue requirement reduction from the existing capacity contract. . . . In addition to the amortization "revenues" to be recorded monthly in Accounts 447.74 and 447.71, WWP intends to reflect an additional revenue credit for ratemaking purposes so that the total book "revenue" in the accounts reflected for ratemaking purposes is equivalent to the revenue that would have occurred absent the assignment of the contract.

(Emphasis added) (Exh. T-203, p. 10, l. 19 - p. 11, l. 20). In this manner, the revenues for retail ratemaking purposes would be equal to the revenue stream under the original contract.[7]

(4) It is also important to understand that the Company "monetized" the difference between the original contract rate of approximately $10.00/KW-month and the capacity price in the new contract of $1.00/KW-month, which represented approximately $16.2 million per year for 16 years (1999-2014). On a present value basis, utilizing a discount rate of 7.83%, this equals $145 million. Essentially, therefore, on a present value basis, the annual amounts from the original contract that were monetized are essentially equivalent to the $145 million up-front payment.

[7] Excerpts from the Application as well as the Public Notice of Filing issued by FERC are provided in Exhibit No. 204.

(5) Furthermore, the last two years of the original PGE Contract (2015 and 2016) were not monetized and remain in place per the original agreement.

The foregoing reasons demonstrate why the revenue stream proposed by the Company in this case (i.e., $18 million per year) is designed to match the original revenue stream prior to monetization. This monetization, after all, was a financial arrangement designed to preserve the original revenue stream and secure the benefits of an above-market contract for ratepayers.

It should be emphasized that the Company did not record a gain on its books for shareholders relating to this transaction, because the revenues associated with the up-front payment were deferred and are being amortized back to ratepayers over the monetization period (1999-2014). (Exh. T-203, p. 12, *ll*. 6-8).[8]

It is important to understand that the original PGE Capacity Sale Agreement included capacity sale prices of approximately $10.00 per KW per month and by 1998 these sale prices were "well above market," as testified to by Mr. Norwood. (Exh. T-203, p. 9, *ll*. 6-21). PGE was acquired by Enron in 1997 and was otherwise pursuing the sale of generating assets, all in the context of electric restructuring in Oregon. As testified to by Mr. Norwood, Avista viewed these changes as "creating increased uncertainty related to receiving the full value of the above-market sales contract for the term of the agreement." (Id.)[9] Staff Witness Buckley acknowledged that the PGE monetization transaction served to reduce the risk associated with any non-performance in the future of the contract by PGE. (Tr., p. 1273, *ll*. 14-17.) In the process, he agreed that the risk associated

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[8] Staff Witness Buckley's reference at page 16 of his testimony (Exhibit T-540) to a Company memo addressing a potential net present value benefit of $32 million is misplaced. That memo, dated May 11, 1998, reflected the early stages of developing an arrangement which did not occur until December of 1998 and contained assumptions different than the actual terms finally agreed upon. (Exh. T-203, p. 12, *ll*. 12-16).

[9] Through the monetization transaction, the Company received an up-front payment of $145 million which covered revenues from January 1999 through December 2014. The capacity sales price in the original contract was reduced from approximately $10.00/KW-month to a fixed price of $1.00/KW-month, or from $18 million to $1.8 million per year. (Exh. T-203, p. 9, *ll*. 15-19).

with the future revenue stream from the above-market contract was shifted away from Avista Utilities and its customers. (Tr., p. 1274, *ll*. 1-3.) Moreover, under the Company's proposal, the revenues associated with the up-front payment were deferred by the Company and are being amortized back to ratepayers over the monetization period (1999-2014). (Tr., p. 1274, *ll*. 8-13.)

Staff, for its part, has proposed that the deferred PGE revenues be used to offset certain expense and rate base items. This proposal should be rejected for several reasons. First of all, as explained above, this transaction was a financial arrangement designed to preserve the original revenue stream for the benefit of ratepayers over the 16-year monetization period 1998-2014. That is why, in this proceeding, the Company has continued to proform into revenues approximately $18 million of monetization revenues. This essentially secures these benefits for ratepayers through time. (Exh. T-203, p. 14, *ll*. 4-8). Staff, however, would essentially shift a major portion of the benefits from the PGE contract forward to the next 3-5 years, depriving ratepayers of substantial benefits in later years. This attempt to "front-end-load" ratepayer benefits is not consistent with the purpose of the monetization (which was to match the revenue stream with the term of the contract). Exhibit 206 compares the Company's "levelized" approach of returning ratepayer benefits with the accelerated proposals of Staff and is attached as Appendix 2.

As discussed above, there is a substantial difference between the "levelized" approach for returning benefits to ratepayers consistent with the term of the contract and the Staff's proposal to accelerate or "front-end" load the benefits. Exhibit No. 206 compares the Company's proposal which would return benefits to ratepayers from the PGE monetization transaction on a "levelized" basis. This Exhibit shows that, under the Company's proposal, just over $12 million per year would be returned to ratepayers over time. As also shown on this Exhibit, Staff's proposal, consisting of several components, including the Rathdrum lease and the buyout of other expense or rate base items, would dramatically shift the benefits to customers into the earlier years, leaving customers worse off in later years, when compared with the Company's "levelized" approach. The Company's approach comports with the basic regulatory "matching" principle that the benefits derived from a long-term contract should generally match the term of that contract.

Furthermore, Staff's proposal would require a write-off by the Company of $9.3 million, inasmuch as Staff proposes a credit to customers of $143.4 million beginning October 1, 2000. The actual balance, however, of deferred revenue as of October 1, 2000, will be $129.5 million, because the amortization had already begun in January of 1999. (See Exh. 205). Accordingly, Washington's share (66.99%) of the difference between $143.4 million and $129.5 million equals $9.3 million. (Exh. T-203, p. 15, *ll*. 12-19). This only serves to underscore the patent unfairness of a proposal that would require the Company to write-off $9.3 million relating to a transaction that has provided, and will continue to provide "tremendous benefits" for the Company's customers. (Id. at p. 15, *ll*. 16-19).

Finally, Staff's proposed use of PGE revenues to offset certain expense and rate base items represents, in essence, a taking of property and an attempt to "micro-manage the utility" in that it would have this Commission substitute its judgment for that of Company management with regard to financial decisions associated with the monetization proceeds. (Exh. T-203, p. 14, *ll*. 10-25). For example, Staff recommended that approximately $55 million of the monetization proceeds be used to buyout the balance of the Rathdrum turbine lease. As testified to by Mr. Norwood, this recommendation was made without the benefit of any analysis of costs or benefits associated with buying out of the lease. (Id. at p. 14, *ll*. 12-25).[10] Staff Witness Buckley acknowledges that Staff

[10] Staff's response to Avista's Data Request No. 5 (Exhibit 548) is revealing:

> Request: Provide any analysis or any other written material prepared by Staff related to Staff's proposal for Avista to buyout the Rathdrum lease.
>
> Response: With the exception of what is contained in Mr. Buckley's testimony and in the supporting workpapers, Staff did not prepare any analysis or other written material related to the proposal for Avista to buyout the Rathdrum lease.

(Exh. T-203, p. 14, *ll*. 17-24).

did not prepare any analyses or other written material relating to Staff's proposal for Avista to buy out the Rathdrum lease, beyond what was otherwise contained in his testimony. (Tr., p. 1262, *ll*. 14-18).

Moreover, Mr. Buckley, on cross-examination, conceded that he did not know whether or not the existing lease arrangement was on more favorable terms when compared with other financing alternatives available today:

> Q: (Meyer) Do you know, Mr. Buckley, whether the existing lease arrangement for the Rathdrum project provides financing at more favorable terms when compared with other financing alternatives available today?
>
> A: I haven't looked at that, so I'm - it's not part of what we provided in our - the issue that we brought up in our testimony but - so I can't really comment yes or no.

(Tr., p. 1263, *ll*. 4-11.)

In response to Public Counsel Data Request No. 164, the Company's analysis showed that, under current circumstances, the after-tax cost of financing the Rathdrum generating plant would be 8.81%, which is significantly greater than the 5.26% cost for the existing Rathdrum lease arrangement. (Tr., p. 1263, l. 15 - p. 1264, l. 23.)

Mr. Norwood testified, on cross-examination, that if you compare the existing after tax financing cost of 5.26% with the current estimated cost to refinance the Rathdrum lease of 8.81%, it would result in an increase in financing costs of $46 million over the remaining 20-year term of the agreement. (Tr. P. 1680, LL. 10-18). And yet, in response to cross-examination, Mr. Buckley acknowledged that:

> . . . the <u>only analysis</u> we did in making this recommendation was one of looking at what dollar amounts were associated with the Rathdrum lease, comparing that to the balance of the lease, and also taking into consideration some qualitative issues such as discussed later, the removing the issue of any sort of prudence on the Rathdrum lease that we would by following our recommendation remove any issues associated with the proper I guess lease treatment of Rathdrum. . . .

(Emphasis added) (Tr., p. 1268, *ll*. 12-21.) Simply put, Staff's proposal was not accompanied with any quantitative analysis of whether a buyout of the lease would be better or worse for the Company and its ratepayers. (Tr., p. 1269, *ll*. 8-19).[11]

Finally, a word needs to be said about the allegations contained within ICNU's testimony concerning this transaction. Specifically, Mr. Schoenbeck, on behalf of ICNU, suggests that the Company concealed information and made a "direct effort to mislead this Commission." (Exh. T-718, p. 14, *ll*. 17-18). In fact, the evidence of record demonstrates that there was no attempt on the Company's part to conceal the PGE transaction from this Commission or other parties nor was there an attempt to garner benefits at the expense of customers. The Company had made full public disclosure of this transaction and its proposal for retail ratemaking relating to this transaction in a necessary filing with FERC over 19 months ago. Staff acknowledged that the Commission "generally receives FERC notices of filings made by the electric utilities regulated by the WUTC." (Tr., p. 1275, *ll*. 1-4.) Accordingly, Mr. Buckley testified that he would have to assume that when the company made the filing at FERC, Staff would have received the notice of filing. (Tr., p. 1275, *ll*. 8-14.) The Company also referenced this transaction in its 1998 Form 10K as well as in the Company's 1998 Annual Report, both of which were issued over a year ago. Thus, on three different occasions, in three different documents, the Company disclosed the transaction. (Exh. T-203, p. 13, *ll*. 1-9). <u>And finally, the Company did not record any gain on its books for shareholders relating to this transaction</u>. (<u>Id</u>.) While the Company might have done more to earlier inform this Commission (although technically not required to do so), there is simply no basis for ICNU's recommendations for a "penalty" by means of a denial of recovery of regulatory fees or the Company's request for an equity adder.

[11] Staff Witness Buckley acknowledged that the documentation relating to the company's decision to initially construct the Rathdrum turbine project was "quite voluminous" including over 500 pages of testimony, exhibits, and studies supporting the decision. (Tr., p. 1272, *l*. 25 - p. 1273, *l*. 6.)

The Company wishes to reiterate that it is opposed to what Staff recommends. Staff's proposal to use $143.4 million of PGE deferred revenues to offset a number of ratebase and expense items would serve to reduce the Company's revenue requirement by approximately $11.4 million beyond that proposed by the Company. (Exh. T-203, p. 16, *ll*. 9-25). The table set forth at page 16 of Mr. Norwood's Rebuttal Exhibit T-203, identifies each of the recommended ratebase and expense adjustments proposed by Staff: they include the buyout of the Rathdrum lease expense (use of $55,277,777 of proceeds); the write-off of the WPI contract and associated amortization ($5,046,868); the reduction of Potlatch purchase power costs through 12/31/2001 ($11,411,452); the write-off of the DSM balance and elimination of the amortization ($31,957,000) and the amortization of the remaining balance of $26,600,000 over 16 years, constituting an overall ratebase reduction of $39.7 million. The deferred revenue balance figures shown in parentheses above total $143,400,097 which equates with the total amount that Staff proposes to use to offset the ratebase and expense items. (Id.)

If, over Avista's objection, the Commission were to decide to shift the benefits of the PGE Contract up front to offset ratebase and expense items as discussed above, the following adjustments would, in any event, need to be made.

1. The Appropriate Balance of PGE Deferred Revenues Is $129,486,000

As testified to by Mr. Norwood, the appropriate starting place for determining the balance of PGE deferred revenues should be as of October 1, 2000, (beginning of rate-effective period), yielding a deferred revenue balance of $129,486,000 not the $143,400,000 proposed by Staff. (Exh. T-203, p. 17, *ll*. 1-8; see also Exh. T-205). As explained by Mr. Falkner, in order to be consistent with other adjustments in the case, the appropriate starting point for the rate base offset calculation should have reflected the deferred revenue balance as of the beginning of the rate year, October 1, 2000 — not as of the end of the test year, December 31, 1998. Accordingly, the starting deferred revenue balance of $143,400,000 as of December 31, 1998, should be corrected to $129,486,000.

(See Exh. 205). The important point is that the Company's revenues from the PGE contract, beginning in January of 1999, were reduced by approximately $16.2 million per year. (Exh. T-203, p. 17, l. 17 - p. 18, l. 7). In addition, the Company began amortizing the deferred revenue balance in January 1999 at an annualized rate of $8.865 million per year, as show in Exhibit No. 205. The amortization of this revenue, as well as the time value of money for an "up-front" payment, is necessary to offset the Company's revenue reduction of $16.2 million per year. (Id.) For the Commission to adopt Staff's proposal in this regard, it would require a write-off by the Company of $9.3 million ($143.4 million minus $129.5 million x 66.99% representing Washington's share).

For his part, Mr. Buckley, as the Staff proponent of this adjustment, apparently did not know that the result would require the Company to write-off $9.3 million related to this transaction. (Tr., p. 1281, l. 20 - p. 1282, l. 3.) The "write-off" is simply not justified, especially in light of the significant benefits that had been preserved by virtue of the transaction for the Company and its customers.[12]/[13]

2. Any Use of Deferred Revenue Should Be Used First to Offset the Company's Ice Storm Costs and Nez Perce Settlement Payments.

As discussed by Mr. Falkner in his testimony, the costs associated with restoring service as a result of the Ice Storm of 1996 were a necessary expense for Avista and should be reflected in

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[12] Mr. Schoenbeck's (ICNU) recommendations relating to the PGE transaction also failed to reflect the fact that the amortization began in January of 1999 and the necessity to recognizing amortization and interest value of up front payments in order to compensate the Company for the $16.2 million reduction in revenue requirement beginning as of that date. (Exh. T-203, p. 18, *ll*. 19-23).

[13] Mr. Parvinen, of staff, proposed two separate adjustments for the Company's investment in the WNP-3 exchange power and to reflect the balance of the Company's investment in DSM. The Company has not otherwise objected to these proposed adjustments, again assuming that the Commission were to accept Staff's "offset" approach over the Company's strong objection. (Exh. T-203, p. 18, *ll*. 8-14).

rates. [See discussion infra, at Section IX.A.2.] Staff has otherwise proposed to use PGE deferred revenues to "clean up" certain expense and ratebase items, (e.g. write-off the balance of the WPI PURPA contract and other DSM balances). In keeping with such an approach, and given the significant benefit realized by ratepayers relating to the PGE contract, this should be viewed as "an excellent avenue to provide recovery of the Ice Storm costs for the Company," as testified to on rebuttal by Mr. Norwood. (Exh. T-203, p. 19, *ll*. 7-18).[14] Should the Commission reject this proposal to use Ice Storm costs as an offset, the Company proposes, in the alternative, that the Commission award shareholders 15% of the PGE deferred revenue balance as of October 1, 2000, to at least provide shareholders with some measure of meaningful benefit for creating this value for customers. As testified to by Mr. Norwood:

> Granting the Company 15% of the balance at October 1, 2000, would provide the Company shareholders a tangible benefit from the PGE Contract, and send a message to the Company that there can be financial benefits to shareholders as well as customers from creating this kind of significant benefit.
>
> Fifteen percent of the balance of PGE deferred revenues at October 1, 2000, for the Washington jurisdiction, would be $13,011,000.

(Exh. T-203, p. 20, *ll*. 7-11).

An additional "clean up" item to be considered by the Commission, if the Commission chose to adopt Staff's "offset" approach, would be to apply PGE deferred revenues to offset the $2.5

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[14] Avista is not proposing to recover the Ice Storm costs more than once. Accordingly, if PGE deferred revenues are used to cover Ice Storm costs, the Company's other adjustment proposed by Mr. McKenzie to use a portion of the gain on the sale of Centralia to offset Ice Storm costs should be eliminated; and, correspondingly, Ice Storm costs should not otherwise be included in Mr. Falkner's Injuries and Damages Adjustment. (Exh. T-203, p. 19, *ll*. 13-17). Total Ice Storm costs are $15,326,416 on a system basis ($12,284,817 assigned to Washington). Accordingly, if PGE deferred revenues are used to cover the Ice Storm costs, this would reduce the Company's revenue requirement by $2,047,470. (Id.)

million up-front payment made by the Company to the Nez Perce tribe as part of an overall settlement agreement.[15]

3. Conclusions

In summary, if the Commission were to use Staff's "offset" approach — but made the necessary adjustments proposed by the Company — this would reduce the Company's originally filed revenue requirement by approximately $8,919,000 (as opposed to Staff's proposal of a reduction in revenue requirement of $11,408,000). (Exh. T-203, p. 21, *ll*. 9-32). It should be emphasized yet again, however, that the Company is strongly opposed to this "offset approach" for the reasons stated above. While such an approach would give Avista customers more of the PGE contract benefits "up-front" in earlier years, it would provide less in ratepayer benefits in the later years of the monetization period. (See Exh. 206).[16]

B. Recovery of Centralia Replacement Power Costs

The Company's interest in the Centralia generating project was transferred to TECWA Power, Inc., on May 5, 2000. For purposes of this proceeding, the Company has removed the ownership and operating costs of Centralia and has included the replacement power costs associated with the TransAlta replacement power purchase. A copy of the replacement power contract with TransAlta was introduced as Exhibit C-214. This replacement power contract represents a "temporary replacement" for a three and one-half year period, as testified to by Mr. Norwood. (Exh.

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[15] The balance of this settlement payment at October 1, 2000, is $2,402,800 on a system basis and $1,609,600 for the Washington jurisdiction. Eliminating this balance with PGE deferred revenues would reduce the Company's proposed revenue requirement by $37,217. (Exh. T-203, p. 20, *ll*. 12-19).

[16] Any remaining balance of PGE deferred revenues, after offsets, should be credited to Avista's customers over a 14.25 year period as opposed to the 16 year period proposed by staff. The Company's monetization of revenues is based on a PGE contract for the period January 1999 through December 2014. Accordingly, any amortization of the PGE deferred revenue balance should not extend beyond December 2014. (Exh. T-203, p. 20, l. 20 - p. 21, l. 3). That is to say, the remaining term from the beginning of the rate year (October 1, 2000) is 14 years and three months — not 16 years. (Id.)

T-203, p. 54, l. 19 - p. 55, l. 4). The Company has developed a Request for Proposals (RFP) that has been filed with the Commission wherein the Company will evaluate resource alternatives over the longer term, in order to replace the Centralia output. In the meantime, this short-term purchase from TransAlta will provide time to solicit and evaluate bids through the RFP process and, if necessary, possibly construct new resources. (Id.)

Staff, however, while it proposes to flow through the gain on the sale of Centralia to customers, would deny recovery of the replacement power costs. According to Staff Witness Buckley, the Commission should deny recovery of the replacement power costs "until the Company makes a sufficient showing regarding the long-term cost of replacing Centralia Power." (Exh. T-540, p. 35, l. 14).

In his testimony, Company Witness Norwood outlined the tests previously articulated by this Commission with regard to the prudence of any resource acquisition:

> The test this Commission applies to measure prudence is what would a reasonable Board of Directors and the Company management have decided given what they knew or reasonably should have known to be true at the time they made a decision. This test applies both to the question of need and the appropriateness of the expenditures.

(See Eleventh Supplemental Order, dated September 21, 1993, Docket No. UE-920433). (Exh. T-203, pp. 10-11). And again, this Commission articulated a "reasonableness" standard in its Nineteenth Supplemental Order in Docket No. UE-920433, dated September 27, 1994:

> The Commission relies upon a reasonableness standard. The Company must establish that it adequately studied a question of whether to purchase these resources and made a reasonable decision, using the data and methods that a reasonable management would have used at the time the decisions were made.
>
> The prudence standard adopted in prior Commission Orders is easily applied to any resource decision, whether it is to build or to purchase. The utility must first determine whether new resources are necessary. Once a need has been identified, the utility must determine how to fill that need in a cost-effective manner.

(Id.). Previously, Mr. Norwood explained during his direct testimony the process by which the Company gave consideration to the TransAlta replacement power purchase. The factors considered included: the recognition of an immediate need for resources of approximately 200 MW; the need for the replacement resources to be contingent upon a sale of Centralia occurring; the opportunity for a replacement resource that excluded the spring run-off, when Centralia is often displaced and the Company is generally in a surplus condition; and finally, a comparison of the TransAlta purchase costs to the price of other power products in the marketplace at the time. (See Transcript pp. 260-265) (see also Exh. T-203, p. 56, *ll*. 26-32).

To begin with, the sale of Centralia created an immediate need for resources. The Company's load/resource tabulations from its 1997 Least Cost Plan and the draft plan dated November 10, 1999, both show an energy deficiency even before the sale of Centralia. (See Exh. 211). Moreover, page 21 of Exhibit T-151 shows an energy deficiency, prior to the sale of Centralia, for every month that the replacement purchases from TransAlta were made (i.e., July-March). (Id. at p. 57, *ll*. 3-10). Neither constructing new resources nor acquiring energy efficiency measures represented feasible near term solutions. (Id.)

Because the ultimate sale of Centralia was uncertain, it was necessary for the replacement resource to be contingent upon the sale of Centralia actually occurring. Accordingly, the replacement resource had to have a flexible start date and be contingent upon the closing of the sale which required regulatory approvals and was, accordingly, by no means certain.[17]

Mr. Norwood described, in some detail, the "market assessment" engaged in by the Company in order to evaluate alternatives:

> The Company conducted a number of market assessments to determine the heavy-load products, flat products, and seasonable products that were available in the wholesale market to meet the resource needs. The brokers that the Company work

[17] As explained by Mr. Norwood, TransAlta was able to offer this flexibility because they were in the "opposite position" of Avista – that is, they were interested in a sale opportunity contingent upon the purchase of Centralia. Were it not for the TransAlta opportunity, the Company would have had to pay a premium for this flexibility. (Exh. T-203, p. 57, *ll*. 12-22). Moreover, if the Company had waited until the sale had closed before purchasing replacement power, this would have placed the Company and its customer in a "disadvantageous seller's market," given the fact that the Company would have been short on power and "everyone would have known it." (Id.)

> with provide access to multi-year products offered by major energy suppliers such as Enron, Duke Energy, Williams, El Paso Power, PowerEx, PGE and many others. These brokers provide the Company with the lowest price offered by these energy suppliers for the various energy products. The advantage to both sellers and buyers in using brokers is the ability to remain anonymous in the pricing that is both offered and bid. The use of multiple brokers, as well as direct contacts with other utilities and marketers, provides a confidence that the prices are representative of the market. Two of these assessments are documented on pages 5 and 6 of the Confidential Exhibit No. C-214.

(Exh. T-203, p. 57, l. 34 - p. 58, l. 2).

In conducting its market assessments and soliciting bids, the Company considered economic dispatch, load factor, and seasonality, given that the replacement resource actually selected was a nine-month product each year from July through March. Because the Company was already deficient approximately 100 average megawatts for July-March prior to the sale of Centralia, the Company needed a high load factor product. The actual economic analysis, which compared the cost of the TransAlta purchase with other power alternatives is provided on pages 1-4 of confidential Exhibit No. C-214. This Exhibit clearly shows, based on a comparison of values, that the TransAlta purchase is less than any of the alternatives.[18] Accordingly, the TransAlta alternative produced "valuable flexibility at a price below the cost of other market alternatives, which resulted in lower rate impacts than the other alternatives," as testified to by Mr. Norwood. (Id. at p. 58, *ll*. 9-23). The actual rate impacts associated with replacement power are provided in Exhibit C-194, previously introduced by Commission Staff.

Staff Witness Buckley and ICNU Witness Schoenbeck are simply wrong when they assert that the Company failed to conduct studies analyzing the actual size or shape of replacement power or otherwise provide data or analysis to demonstrate the prudence of its decision. In point of fact, as discussed above and as contained within the Company's exhibits (see e.g., Exh. 211 and Exh. C-

[18] This confidential Exhibit is the same Exhibit as sponsored by Mr. Buckley previously as Exhibit No. C-546.

214), the Company has readily satisfied the prudence standards outlined by the Commission in acquiring this three and one-half year replacement power.

Moreover, Public Counsel, in recommending that the replacement power cost be disallowed, is simply raising the same issue previously presented to the Commission and rejected in Public Counsel's Motion to Reopen Centralia Docket (Docket No. UE-991255), dated April 11, 2000. In rejecting this motion, the Commission, at page 8 of its Fourth Supplemental Order, dated April 21, 2000, stated that "any comparison of Centralia costs to replacement power costs must include the scrubber investments that are necessary to keep the Centralia Plant operating." As explained in Mr. Norwood's rebuttal testimony: "A comparison of the replacement power costs for each year shown on pages 1-4 of confidential Exhibit No. C-214 in the column labeled "Total TransAlta" (on the line labeled "Jan-Dec"), with the ownership and operating costs of Centralia in Mr. Lazar's Exhibit 697 shows that the replacement purchase cost is lower than the cost of Centralia including the scrubbers." (Emphasis supplied) (Exh. T-203, p. 59, *ll*. 13-17).[19]

The issue of the Centralia gain (as discussed below) and the cost of necessary replacement power were previously addressed in the Centralia Sale Docket (Docket No. UE-991255), as well as in this proceeding. Indeed, the Commission in its Centralia Order (supra) directed that the disposition of the gain were to be addressed in this rate proceeding. There is no need for yet a third, future docket, as suggested by Public Counsel, to again revisit these issues. In the meantime, it would be patently unreasonable for customers to enjoy the benefit of the gain on the sale of Centralia, by virtue of an order in this Docket, while otherwise requiring the Company to absorb the cost of power to replace the resource until some future date in some future proceeding.

Interestingly enough, Staff is taking issue with neither the need to acquire resources in the absence of Centralia or the price which the Company actually paid for the replacement power:

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[19] The replacement purchase is higher than the current cost of Centralia excluding the scrubbers, which is why there is an increase in revenue requirement associated with replacement purchase, as explained by Mr. McKenzie in his rebuttal testimony (see Exh. T-447.)

> Q: (Meyer) Staff is not taking issue in this case with the price, with the price paid for the replacement power, is it?
>
> A: (Buckley) It's <u>not taking issue with either the price or the fact that the Company may have needed to acquire something</u>. The issue is, is that something was acquired.

(Emphasis added) (Tr., p. 1299, *ll*. 11-17.) Mr. Buckley also agrees that the Company should not have committed to taking delivery of replacement power <u>prior to</u> knowing whether the sale of Centralia would actually occur. (Tr., p. 1300, l. 19 - p. 1301, l. 4.)

Mr. Buckley also agreed that the implementation of demand side management would not have been a viable alternative to meet an immediate need for 200 megawatts of capacity and 140 average megawatts of energy as a result of the Centralia sale. (Tr., p. 1301, *ll*. 12-17.) Moreover, he agrees that the construction of a new generating resource would not have been a viable alternative to meet these needs in this time frame. (Tr., p. 1301, *ll*. 18-22.)

Staff still argues, however, through Mr. Buckley, that the Commission should deny recovery of the replacement power costs "until the Company makes a sufficient showing regarding the <u>long-term cost</u> of replacing Centralia power." (Exh. T-540, p. 35.) (Emphasis added.) In the meantime, however, the Company needed to avail itself of a short-term replacement contract. When directly confronted with the issue, Mr. Buckley seemed to equivocate:

> Q: If the long-term, and those were your words not mine, if the long-term cost of replacing Centralia, for example, reflected a newly constructed resource, and assume with me if you will that it took more than a few years to bring such a new resource on-line, would you in the meantime recommend that the Company go without a short-term replacement contract?
>
> A: If the Company had sold Centralia?
>
> Q: Which it did.
>
> A: Which it did. I guess that's where I'm having trouble answering the question is what are - what we're trying to do is to hold customers, at least until a proper determination is made of the proper long-term replacement cost, harmless for the company's decision to sell

> Centralia. So to answer that without putting it in that context is a bit difficult. We're not arguing that the Company should not have obtained a short-term resource.
>
> Q: You're not taking issue with the price of that resource?
>
> A: We're not taking issue with the price. . . . .

(Tr.,p. 1302, L.24-p. 1303, L. 19) In short, the Staff neither takes issue with the Company's need to obtain a short-term replacement resource or the price of that power; instead, it seeks to hold ratepayers harmless - at the expense of the Company - until sometime in the future when the long-term cost of permanently replacing the Centralia power can be determined. That is patently unfair to the Company and its shareholders.

Staff is left to argue that it has not seen "any analysis that says or that would indicate that acquiring a three-year contract with TransAlta and then making some future determination is the least cost option." (Tr., p. 1306, l. 25 - p. 1307 - l. 4.) This flies in the face of the evidence of record in this proceeding that an analysis was conducted of replacement alternatives available and that the Trans-Alta replacement power was the least cost option. Indeed, Mr. Buckley admitted that the Company conducted a market assessment and solicited bids through brokers that considered economic dispatch, load factor, and seasonality, before it made its decision to purchase replacement power from TransAlta. (Tr., p. 1307, *ll*. 11-17.) Moreover, Exhibit C-214 provides the actual economic analysis justifying the purchase of replacement power - which demonstrates that the TransAlta purchase was less than that of any of the other alternatives, given the parameters. (Tr., p. 1307, l. 18 - p. 1308, l. 19.) And, nowhere, have Staff or Intervenors taken specific issue with whether or not the bid parameters were appropriate.[20]

C. Market Transaction Adjustment

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[20] Elsewhere, in response to questioning by Chairwoman Showalter, Staff Witness Buckley testified that "I don't think we would deny recovery of those costs. It's similar to the Potlatch contract, that it's a contract that they have, and we're not saying it shouldn't be recovered." (Tr., p. 1375, *ll*. 18-21.)

The Company has proposed to exclude the gains and losses associated with short term commercial trading activity from the ratemaking process and to otherwise reduce corresponding utility overhead costs by $306,000, representing Washington's share relating to this activity. (Exh. T-203, p. 22, *ll*. 6-12). Staff, however, has proposed an adjustment which would guarantee $3,450,000 (Washington's share) of margins annually to customers relating to commercial trading activity and has eliminated the Company's proposed overhead cost reduction. ICNU also has proposed an adjustment to guarantee $4.2 million of margins annually to customers relating to this activity. (Exh. T-718, p. 22, *ll*. 13-16).

In his rebuttal testimony, Company Witness Norwood carefully explains why the methodology chosen by Staff Witness Buckley is seriously flawed. In order to estimate what he considers to be a "normalized value" of commercial trading margins, Mr. Buckley subtracts the same proforma Short-Term Sales and Short-Term Purchase values from the actual sales and purchase values for each of the years 1996 through 1999. This flawed methodology produces results that, in the words of Witness Norwood, are "completely unreliable and unusable." (Id. at p. 22, l. 23, p. 23, l. 2). Mr. Norwood explained why the relationship of the Short-Term Sales and Short-Term Purchases is "unique to the load and resource balance for the proforma rate year July 1, 2000 through June 30, 2001" (Id. at p. 25, *ll*. 5-9). It is, therefore, entirely inappropriate to utilize these same figures for each of the years 1996 through 1999 as proposed by Mr. Buckley. After all, any change in the load/resource balance would change the relationship of these Short-Term Sales and Short-Term Purchases. (Id.) By way of example, Mr. Norwood testified on rebuttal how simply adding an additional 100 average MW to the Staff's Dispatch Model would produce dramatically different results, making the Company a net seller of short-term energy equal to $2,854,700, instead of a net purchaser of $14,879,800. (Id. at p. 25, *ll*. 10-27). This difference represents a "swing" in that sales and purchase relationship of $17,734,500. (Id.)

Simply put "the load/resource balance for each year is different, and will result in a different relationship for the Short-Term Sales and Short-Term Purchases." (Id. at p. 25, *ll*. 1-11). If any of six different variables identified by witness Norwood vary from year to year, it will result in a different sales and purchase relationship; these variables include: firm retail load obligations; firm wholesale contract obligations; firm contract rights; hydroelectric generation, thermal generation and short-term market prices. (Id.) By way of yet another example, Mr. Norwood isolated just one variable for the year 1997 and used the known level of hydrogeneration. The result: the sales and purchase relationship for 1997 would have been substantially different than the assumed $14,879,800 net purchase assumption used by Mr. Buckley in his analysis — i.e., the Company would have been a net seller of $5,111,600 as opposed to a purchaser of $14,879,800, as assumed by Mr. Buckley. (Id. at p. 27, *ll*. 2-6). As testified to by Mr. Norwood, "this single adjustment based on a known level of hydroelectric generation for 1997 would cause Mr. Buckley's methodology to actually show a market transaction net revenue loss of $2,648,390." (Id. at p. 27, *ll*. 21-23). Simply put, there are "too many variables" that have a major impact on the net difference between sales and purchases in order to be able to arbitrarily assume a steady-state relationship between them in each and every year chosen by Mr. Buckley. The result is that the methodology chosen by Staff Witness Buckley "in no way provides any indication of the trading margins that occurred in those years." (Id. at p. 28, *ll*. 5-6). According to Mr. Norwood such a methodology "violates very basic fundamental analysis related to these power supply revenues and expenses." (Id. at p. 28, *ll*. 7-10).

Mr. Buckley was asked to refer to Exhibit 552 containing Staff's response to an Avista data request in which Staff was asked the following question:

> For each of the resources listed on page 41 by Mr. Buckley, please fully explain the benefits available that are not already reflected in the Company's filing from each of the resources, and provide specific examples of how these benefits from each of these items are created.

(Tr., p. 1313, *ll*. 1-11.) Nowhere, however, in the response could Mr. Buckley provide specific examples of benefits that are not already reflected in the Company's filing:

> Q: But, Mr. Buckley, the question, I will put it to you again, where in this response do you provide specific examples of benefits that are not otherwise reflected in the Company's filing?

A: Well, in the response there is not specific examples there.

(Tr., p. 1314, l. 23 - p. 1315, l. 3.)

For his part, Staff Witness Buckley agreed, that as the primary Staff Witness in this area, in order to fully analyze the power supply revenues and expenses for Avista, it is critical to have a clear understanding of the power supply operations specific to Avista. (Tr., p. 1254, L.22 - p. 1255, l.1.) He acknowledged that it requires some measure of detailed understanding of the power supply situation as it impacts Avista per se. (Tr., p. 1255, *ll*. 6-9.) However, Mr. Buckley made no visits to Avista's offices in order to discuss power supply costs or otherwise observe power supply operations, either in this case or for any reason in the past year. (Tr., p. 1255, *ll*. 10-19.) Moreover, in the past three years, he has not visited the trading floors of any of the investor-owned utilities regulated by this Commission. (Tr., p. 1255, *ll*. 20-23.)[21]

Furthermore, Mr. Buckley acknowledged in response to a company data request that he had "carried out no analysis of wholesale market prices for the specific period January 1, 2000, through December 31, 2003." (Tr., p. 1259, *ll*. 8-20.) In short, he has not done any additional analysis of market prices for purposes of this proceeding. (Tr., p. 1261, *ll*. 5-10.)

ICNU, likewise, proceeds on a faulty premise. Its witness, Mr. Schoenbeck, has "cherry picked" a single year (1998) from data provided in response to Staff Data Request No. 314; in so doing, he has also ignored all of the transaction costs associated with this trading. If ICNU had made use of the information contained in the Company's response to Request No. 314, together with other known trading-related revenues and expenses, this would have produced, instead, sharing of $683,503 per year to customers and the same amount to shareholders, based on a 50/50 sharing arrangement. (Id. at p. 29, *ll*. 1-21). Even so, the information utilized by ICNU in response to Staff

[21] Nor has Mr. Buckley personally attended any of the three Technical Advisory Committee meetings held during the past year where the Company has presented information to all stakeholders relating to its resource plans. (Tr., p. 1335, *ll*. 4-24.)

Data Request No. 314 do not include all of the related transactions and transaction costs and are not otherwise relied on by the Company for accounting purposes. (Id. at p. 29, *ll*. 24-26).

Finally, when the Idaho Public Utilities Commission recently addressed the commercial trading issue in its IPUC Order No. 28097, dated July 29, 1999 (Case No. WWP-E-98-11), it rejected a similar Intervenor proposal to calculate trading margins involving the difference between Short-Term Sales and Short-Term Purchases similar to the proposal of Mr. Buckley.[22]/[23]

In the final analysis, however, the Company has publicly announced plans to eliminate short-term commercial trading activities, that are unrelated to optimizing the Company's system resources. For his part, Mr. Buckley stated that he understood the Company is no longer planning on engaging in commercial trading activity in the future. (Tr., p. 1310, l. 20 - p. 1311 - 1.)

D. Use of Appropriate Water Record for Normalizing Hydroelectric Generation

The Company proposed the use of the 1929-1988 sixty-year historical stream flow record for purposes of normalizing hydroelectric generation for rate-making purposes. The Staff, for its part, recommended the continued use of the rolling forty-year average methodology, which would include the 1949-1988 forty-year period. Staff and Company stipulated to a settlement of this issue (Exh. 740), which stipulation was approved by this Commission. By this stipulation, Staff and Avista agreed to the continued use of the rolling forty-year average methodology for the purpose of normalizing hydroelectric generation for rate-making purposes. Moreover, for purposes of this proceeding, Staff's adjustment reducing power supply expenses relating to this stream flow record

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[22] In its Order, the Idaho Commission adopted an A&G cost reduction relating to commercial trading equal to $876,370 on a system basis, or $283,944 for the Idaho jurisdiction. The Washington jurisdictional share of that number (66.99%) would be $597,080 per year. (Exh.T-203, p. 30, *ll*. 24-27).

[23] If the Commission does properly accept the Company's proposal to exclude commercial trading margins, the Company does acknowledge that FERC fees should be reduced by $279,280 on a Washington jurisdictional basis. (Exh. T-203, p. 31, *ll*. 1-4).

issue shall be revised to reflect an expense reduction of $2,950,000 on a system basis, rather than $5,900,000, as originally proposed. The total power supply adjustment ultimately adopted by the Commission in this proceeding should incorporate these provisions.

E. Recovery of Short-term Capacity Purchase Expense

The Company has included expenses associated with short-term capacity purchases of $955,000 in the test period, based on the actual cost of short-term capacity purchases during the 1998 test period. (Exh. T-203, p. 42, *ll*. 4-6). Staff has removed all expense for short term capacity purchases, arguing that the Company has not provided documentation to support these expenses. (Id. at p. 42, *ll*. 8-10).

In fact, the Company has provided extensive documentation that supports the need for such short-term capacity purchases. As shown in Exhibit 211 (Least Cost Planning Report), the Company has consistently relied upon the combination of short-term purchases and long-term capacity resources in order to meet its firm load obligations. (Id. at p. 42, *ll*. 12-20).[24]

The Company, as shown in our response to Staff Data Request No. 61, consistently purchases November-February four-month capacity products, as well as year-around 12-month products. Therefore using 6 months as a reasonable weighted average, the Company's proposed short-term capacity purchase expense of $955,000 for 337 MW of capacity results in a cost of $0.47 per KW-month ($955,000 ÷ 337,000÷ 6). According to Mr. Norwood:

> This is a very reasonable cost to customers for firm capacity for the proforma rate year. If the Company were to not rely on short-term capacity purchases for a portion of its total capacity requirements, the purchase of long-term firm capacity would result in a much higher cost to customers.

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[24] Indeed, if the Company were forced to acquire only long term resources because the costs of short term capacity resources were denied for ratemaking purposes, this would result in higher costs to customers. (Id. at p. 42, *ll*. 18-20).

(Id. at p. 44, *ll*. 19-21).

As stated earlier, the Company used 1998 actual short-term capacity purchases as the normalized amount in this case. If, however, one were to use a five-year average of short-term capacity purchase expenses (see page 2 of Exhibit 212), one would arrive at essentially the same place. The 5 year average is $935,313, as compared with the 1998 actual capacity purchase of $955,000. (Id. at p. 45, *ll*. 15-20). The Company would not object to using the 5 year average figure in this case; however, Staff's proposal to remove all amounts for any short-term capacity purchases enjoys no support in the record.

Lastly, it should be emphasized that these short-term capacity purchases are not made to support commercial trading transactions. As indicated above, the Company uses a combination of long-term and short-term capacity resources to meet firm load obligations. Accordingly, these short term capacity purchases are not made to support commercial trading transactions and are necessary to serve firm load obligations. (Id. at p. 46, *ll*. 21-22).

F. Dispatch Credit Adjustment

Staff Witness Buckley proposes a "dispatch credit adjustment" to the average market price for short-term energy purchases and short-term energy sales. The impact of Staff's proposal would be to reduce the average short term purchase price from $22.32/MWh proposed by the Company to $18.83/MWh, and to decrease the short-term sales price from $17.43/MWh to $17.03/MWh. (Exh. T-203 at p. 47, *ll*. 15-19). Staff purports to make adjustments related to the flexibility of the Company's hydroelectric system to shape energy between heavy-load and light-load hours.

On rebuttal, the Company explained that, even though the Dispatch Model is not an hourly model, the market prices developed from the Dispatch Model are reflective of a weighted average of market prices for each month of the study, including the flexibility of the Company's hydroelectric system and heavy load and light load pricing. After the study is completed the Company compares the resulting prices not only with actual historical market prices experienced, but current and future short-term market conditions in order to test for reasonableness. (Id. at p. 48, *ll*. 1-4). When tested in such a fashion for "reasonableness," both the Company's proposed short term purchase price ($22.32) and the Staff's proposed price ($18.83) are well below both current and expected future market prices. As testified to by Mr. Norwood:

> The Company is a net purchaser of short-term energy. As I will show below, the Company has already significantly understated its revenue requirement, by using a short-term purchase price of $22.32/MWh. This price is well below the current and expected future market prices. Mr. Buckley's adjustment would further reduce the Company's revenue requirement, based on an unreasonable low short-term purchase price.

(Exh. T-203, p. 48, *ll*. 8-13).

Simply put, Mr. Buckley, through his adjustment, is suggesting that the Company will be able to purchase short-term firm energy during the upcoming rate year (October 2000 through September 2001) at an average price of $18.83/MWh. This simply does not pass the test of reasonableness given dramatically increasing wholesale market prices over the past several years.

As shown on page 1 of Exhibit 213 (Attached as Appendix 5), the Company's average short-term purchase prices increased from $12.74/MWh in 1996 to $27.54/MWh in 1999. Not only have the average short-term market prices increased, but there has also been a sharp increase in the volatility in short-term market prices. See pages 2-4 of Exhibit 213 showing graphs of daily heavy load and light load prescheduled electric prices at the Mid-Columbia for 1998 to year-to-date 2000. Indeed, real-time prices at the Mid-Columbia during May 2000 rose to over $700/MWh. (Exh. T-203 at p. 51, *ll*. 13-14). Moreover, the short-term firm market prices at both Mid-Columbia and the California-Oregon border (COB), even during light load hours, are at or above $40.00/Mwh — well above the $18.83/MWh proposed by Staff Witness Buckley. (Id. at p. 52, *ll*. 1-17). If any adjustment is to be made for short term market prices through this dispatch credit adjustment proposed by Staff, it should reflect a substantial increase in market prices — not the decrease proposed by Staff.[25]

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[25] In fact, instead of using the Company's number, if one were to use even the 1999 average market price of $27.54/MWh, this would serve to increase the Company's power costs by

Indeed, this whole discussion underscores the need for a power cost adjustment clause, given the dramatic volatility in purchase power costs, as testified to by Mr. Norwood:

> This illustrates the exposure that the Company has to changes in short-term market prices. The importance of the Company's Power Cost Adjustment (PCA) mechanism is even more apparent given the recent increases in market prices and the increased volatility.
>
> Based on current and expected market prices for the near future, the Company has already <u>significantly understated its power costs</u>. Any further reduction in power costs using Staff's proposed Dispatch Credit would be unreasonable and should be rejected.

(Exh. T-203, p. 53, *ll*. 9-14) (Emphasis supplied).

G. <u>Colstrip Equivalent Availability Factor</u>

The Company had proposed an 83% equivalent availability factor for Colstrip Units 3 and 4; Staff, through Mr. Buckley, proposed an adjustment to increase that factor to "about 86%." The impact would be to reduce the Company's proforma expense by $428,400 (system) or $286,985 for the Washington jurisdiction. (Exh. T-203, p. 60, *ll*. 18-23).

Staff's adjustment, as explained by Company Witness Norwood, is too high for these units, given the fact that these large generating units do "break down from time to time" even though they may experience a number of years with relatively high availability factors. The Company presented evidence that during the 14 year period that both Colstrip Unit 3 and 4 had been in service, the average EAF (equivalent availability factor) has been 82.1%. (<u>See</u> Exhibit 215 at p. 1). Similarly, the North American Electric Reliability Council (NERC) tracks equivalent availability factors for major generating projects across the country. This information, as explained by Mr. Norwood, is available in its Generation Availability Data System (GADS) report. (<u>See</u> Exhibit 215, pp. 2-3).

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approximately $9 million on an annual basis, as compared to the power costs proposed by the Company in this case.

That data shows an availability factor of 82.98% for the period 1994-1998. (Exh. T-203, p. 61, *ll*. 4-20).

Therefore, whether we use the EAF for the period the units have been in service (1986-1999) or the GADS data (1994-1998), showing 82.10% and 82.98% availability factors, respectively, we see that this information supports Avista's use of an 83% EAF — not the 86% proposed EAF factor by Staff. (Id.)

H. Adjustment to Mid-Columbia Proforma Power Costs

The Company does not object to Staff's proposed adjustment to reduce the Mid-Columbia (Wanapum and Priest Rapids) proforma power cost by $222,000 on a system basis. The Company recognizes that when it filed its case in October of 1999 it did so with the best information available at the time and the Company is not opposed to incorporating updated information with regard to proforma power costs as long as such adjustments "go both ways." (Exh. T-203, p. 62, *ll*. 6-9).

IV. DISPOSITION OF CENTRALIA GAIN

The Commission issued its Second Supplemental Order on March 6, 2000, and its Fourth Supplemental Order on April 21, 2000, in Docket No. UE-991255 pertaining to the sale of Avista's 15% interest in the Centralia plant.[26] In its Order, the Commission directed that treatment of the customer's share of the gain was to be addressed in this proceeding. It also prescribes how the gain is to be calculated and shared between shareholders and customers.

In response, the Company has proposed, in its direct case, the following for the disposition of the gain. First of all, the Company proposes that the customer's share of the gain be used to offset the Washington share of Ice Storm 1996 costs. The remaining amount of the gain was to be

[26] The Commission also issued an Original Order on March 22, 2000, and a Clarifying Order on April 21, 2000 in Docket No. UE-000080 pertaining to the sale of Avista's 2.5% interest in the Centralia plant acquired from Portland General Electric.

amortized over an eight-year period as was recently ordered in our Idaho Centralia case. Finally, the replacement power costs, as reflected in Exhibit C-194, should be included in this proceeding.[27] Exhibit 448 [attached hereto as Appendix 3] shows the Company's proposal on the treatment of the customer's portion of the Centralia gain and the resulting impact on the Company's electric revenue requirement. As shown in this Exhibit, the Company would first use the customer portion of the after-tax Centralia gain of approximately $19.9 million to offset Ice Storm costs of approximately $8 million, as shown on this Exhibit. The remaining after-tax gain of approximately $11.9 million would then be amortized to customers over an eight-year period. This serves to increase net operating income by $1,488,232 and reduces rate base by $11,161,741, as shown in this Exhibit. The net impact on the Company's revenue requirement shows a reduction of approximately $6.1 million associated with this proposal. After the rate base and costs associated with Centralia are removed from the test period and the replacement cost of power is added (which together serve to otherwise increase the revenue requirement by $4.1 million), the net impact on revenue requirement from all the adjustments is a decrease of approximately $2.0 million. (See Exh. T-447, p. 3, l. 11 - p. 4, l. 8).

As testified to by Mr. McKenzie, to the extent that the customer portion of the gain is increased or reduced, as final figures become available, entries would be made to adjust the deferred customer portion of the gain accordingly. In a future rate proceeding, the amortization amount reflected in rates over the amortization period would be adjusted to reflect any adjustments to the deferred gain that may have occurred. (Id. at p. 5, *ll*. 8-13).

Mr. Lazar, on behalf of Public Counsel, objects to the apportionment of state income taxes associated with the gain. He argues that the Oregon and California State income taxes associated with the gain on the Centralia sale should not be apportioned to the Washington and Idaho

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[27] The Ice Storm costs, if offset by the customer's share of the Centralia gain, would otherwise be removed from the injuries and damages adjustment sponsored by Mr. Falkner.

jurisdictions. As explained by Company Witness McKenzie, however, Mr. Lazar's position is totally without merit:

> To expect gas customers in Oregon and California to pay State income taxes associated with the Centralia sale is nonsense. State income taxes are a cost associated with the sale and should be shared by jurisdictions receiving the benefit of the gain on the sale.

(Id. at p. 5, *ll*. 22-26). (See also Exhibit 449 showing the calculation of state income taxes applicable to the gain.)[28]

As a related matter, Staff's proposal to change the jurisdictional allocation percentage applicable to the Centralia gain should be rejected. The allocation factor used in the Centralia sale dockets to allocate the gain between Washington and Idaho was 66.99% for Washington and 33.01% for Idaho. This is also the same production/transmission allocation factor that is used in this proceeding for the 1998 test period. This allocation factor has also been accepted by the Idaho Public Utilities Commission to allocate the Centralia gain. In fact, updating the factor would result in a reduction in the gain allocated to Washington operations, as the new factor for Washington is 66.14% (not 66.99%). (Exh. T-447, p. 8, *ll*. 4-18).[29] This was acknowledged by Staff witness Schooley. (Tr. P. 1486, 1. 18-p. 1487, l. 3).

Finally, Staff's proposal to establish a Centralia bill credit equivalent to the DSM tariff rider should be rejected. Staff proposes that a separate item should show on the bill for a "Centralia bill credit." There is no need to separately state the credit on the customer's bill; such a rate adjustment is, after all, no different than other rate adjustments which are not shown on the customer's bill.

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[28] The calculation and allocation of the gain between customers and shareholders follows the Commission's orders and uses the same methodology that the Company used in its "Attachment A" that was affirmed by the Commission in its Fourth Supplemental Order in Docket No. UE-991255, with the above-discussed refinement for state income taxes. (Exh. T-447, at p. 7, *ll*. 7-11).

[29] The allocation factor accepted by the Commission should remain in effect until the end of the amortization period applicable to the gain. (Id. at p. 8, *ll*. 15-18).

Indeed, only municipal taxes are separately stated on a customer's bill. Furthermore, such billing adjustments require costly changes to the Company's billing system. (Exh. T-447, at pp. 8-9).

Moreover, there is no rational basis for setting a Centralia billing credit equal to the DSM tariff rider rates, as explained by Company Witness McKenzie. (Id. at p. 9, *ll*. 2-7). The tariff rate should, instead, be based on a stated amortization period for the Centralia gain and not arbitrarily tied to the DSM tariff rider rates. (Id.)

Mr. Schooley, was quite candid in response to cross-examination, when he acknowledged that the only logic of using the DSM tariff rider rate for purposes of Centralia gain amortization is that we have such a DSM tariff rider rate in effect:

> Q: So the only logic to using that type of amortization to cause it to equal the DSM tariff rider rate is the fact that you have a DSM tariff rider rate in effect at a certain level at that time, right?
>
> A: Yes, I think it was chosen just as a convenient number and as a, in some sense, an equivalent or another type of power cost. And then you could have a debit for power cost or a charge against a credit.
>
> Q: But no other logic than just that?
>
> A: No, I don't believe so.

(Tr., p. 1488, l. 23 - p. 1489, l. 8.)

V. A POWER COST ADJUSTMENT MECHANISM (PCA), IN ITS SIMPLIFIED FORM, SHOULD BE ADOPTED BY THE COMMISSION IN THIS PROCEEDING

Elsewhere in this Brief, Avista has discussed the significant amount of volatility in power supply expenses due to weather-related changes in hydro generation and short-term energy prices. (See Section III.F.). The volatility in short term energy prices for purchases necessary to serve our load obligations has increased dramatically and shows no sign of abating. In order to address this increased risk, Avista has proposed a PCA to track changes in power supply expenses due to weather-related variations in hydro generation and short-term energy prices.

Staff and Intervenors, in their direct testimony, raised a number of technical objections to the PCA, as <u>originally</u> proposed by the Company in this proceeding. On rebuttal, the Company, through Witness Johnson, addressed each of these technical objections and proposed a much-simplified version of the PCA that will be easy to administer and audit. (See Exh. T-426).[30]

Exhibit 427 contains a schematic diagram that illustrates the inputs and steps in the PCA calculation (this exhibit is attached to this brief as Appendix 4). It is important to remember that <u>only two inputs vary</u> in each month's calculation: (1) the Dow Jones Mid Columbia Index Prices and (2) hydro generation. All other inputs remain constant at levels that are otherwise included in the normalized power supply expenses included in retail rates established in this proceeding. In its simplified PCA proposal, the Company has removed all technical objections relating to (1) PURPA expense changes, (2) thermal generation changes, (3) Rathdrum fuel cost changes, and (4) the Company's calculation of the energy price. Therefore, as testified to by Mr. Johnson, the <u>only variables remaining</u> in the PCA are actual hydro generation and market energy prices (as determined by the Mid Columbia Index). (Exh. T-426, p. 3, ln. 11-20).

Staff and Intervenors suggest that the implementation of a PCA should carry with it a cost of capital reduction. The Company expressed its willingness to reduce the authorized return on equity by ten to fifteen basis points as it relates to the implementation of a PCA, in order to recognize the reduction in risk. (Tr., p. 1644, *ll*. 2-9).

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[30] Indeed, staff witness Buckley noted in his testimony that the Commission has "consistently stated that it favors mechanisms that insulate a company from the noncontrollable effects of fluctuations in hydro conditions," if various conditions are met, including the receipt by ratepayers of some benefit of a cost of capital reduction, if there is a linkage to those factors that are weather-related, and if such a mechanism reflects a short-run accounting procedure that reflects short-run cost changes. (Exh. T-540, p. 44, ln. 21-p. 45, ln. 6). As discussed above, Avista's proposed PCA meets these objectives.

With respect to the various technical issues raised by staff and intervenors, first of all, the Company has modified its proposal to remove the PURPA expense component from the Company's proposed PCA, which will serve to completely remove all long-term contract changes from the PCA. The Company has also addressed Mr. Buckley's concerns at page 46, lines 26-28 of his testimony with respect to Rathdrum generation and fuel costs, where he argues that such costs are not weather-related. Without conceding the point, the Company for purposes of this proceeding has simply proposed to remove from the PCA any changes in generation and/or fuel costs at Colstrip and Rathdrum. Accordingly, thermal generation and fuel expense would not vary from the normalized power supply expenses included in retail rates. This ensures that the only change the PCA will track in the volume of short-term purchases and sales is strictly related to changes in the level of hydro generation.

Next, the Company addressed issues relating to the tracking of short-term purchases and sales and the issue of separating system transactions from commercial trading. In its simplified proposal, the Company proposes to use a market index energy price in place of a calculated energy price otherwise using company data.[31] That market index energy price is the Dow Jones Mid Columbia Firm Index Price. As explained by Company Witness Johnson:

> this modification eliminates concerns regarding how the energy price will be determined, particularly concerns over the separation of system transactions from commercial trading transactions. It clearly establishes the energy price as a factor that is beyond Avista's control, much the same as hydro generation.

(Id. at p. 10, *ll*. 19-23).

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[31] Mr. Buckley acknowledges that short-term market prices are not something over which the Company has control. (Tr., p. 1334, *ll*. 13-17.)

Moreover, the simplified PCA will not have an impact on the Company's incentive to acquire power in a least cost manner. As explained by Mr. Johnson, under the modified proposal, the

> revenues and expenses to customers would be based on a market index energy price for the respective month. The risk is on the Company to make actual purchases and sales at those market rates.

(Id. at p. 11, *ll*. 6-10).

Finally, the Company has addressed Mr. Buckley's concern over the use of an hourly shape adjustment that in this opinion, would be difficult to follow and administer. (See Exh. T-540, at p. 48, *ll*. 4-14). Because the Company proposes to use the same index price (Dow Jones Mid Columbia Index Price) also in the hydro shape adjustment, this will make the calculations very simple, since the only inputs are the market index energy prices and actual hydro generation. (Exh. T-426, at p. 12, *ll*. 19-25). Accordingly, using market index prices for heavy-load hours and light-load hours "eliminates the issue of determining the actual hourly shape of purchases and sales in each month." (Id. at p. 12, *ll*. 25-p. 13, ln. 2).[32]

With the proposed modifications, the PCA calculations will be very easy to administer and audit. Again, the only changes being tracked would be changes in hydro generation and the change in short-term energy prices. As explained by Mr. Johnson:

> There would be only two inputs in the PCA, the Dow Jones Mid Columbia Index prices for on-peak and off-peak hours, and actual hydro generation. The index prices are publicly available to anyone, and the Company's actual hydro generation is recorded by CASSO, an independent control area system services organization.

(Id. at p. 14, *ll*. 10-15).

Moreover, the Company has had a PCA in place in Idaho similar to what was initially proposed by the Company in this case (not the simplified version) since October of 1989. It has

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[32] By using index prices, the purchase and sales hourly shape will match the number of heavy-load hours and light-load hours in the month. Again, the only inputs in this Hydro Hourly Shape Adjustment will be the Dow Jones Index Prices and the actual hourly shape of hydro generation — both of which are easily verified. (Exh. T-426, (WGJ-T) at p. 13, *ll*. 2-8).

worked as intended: when hydro generation is good, customers receive a rebate and when it is not, customers are surcharged. Based on experience derived over the last eleven years, the Idaho Commission staff, using work papers provided by the Company, has "always been able to verify the accuracy and legitimacy of the amounts including in the PCA balancing account," as testified to by Mr. Johnson. (Id. at p. 14, *ll*. 3-6).

This proposal for a PCA, in its much-simplified form, has addressed all pertinent objections of staff and intervenors. The proposal has been the subject of discovery by all parties in this proceeding and the subject of testimony filed by staff and intervenors. In short, all parties have had a chance to fully investigate the Company's proposal and have voiced technical concerns — all of which have been addressed by the Company. Moreover, intervenors in this proceeding represent a broad cross section of the Company's customer base (from low income residential to large industrial). There is, accordingly, no need for the matter to be put off to another proceeding, through a so-called "collaborative" process.[33] The adoption of a PCA is ripe for determination in this proceeding by the Commission. The Company has been and will continue to experience volatility in energy prices; it cannot wait for the initiation and resolution of yet another proceeding to address these risk-factors which are beyond the Company's control.

Mr. Buckley acknowledges that the Company, on rebuttal, addressed the issues raised by Staff with reference to the PCA. He testified that he would "give the Company credit, it did address the issues that I brought up in my direct case, yes." (Tr., p. 1327, *ll*. 18-20.)

It is also important for the Commission to understand the "base" upon which the PCA would operate. The PCA, as explained by Mr. Johnson, will only address the approximately 90 megawatts of power that the Company, on average, buys to meet our system obligations on the short-term

[33] Moreover, this issue is not new with Staff or Intervenors. In the words of Mr. Buckley "we have kind of hashed over these issues for a few years with the Company." (Tr., p. 1329, *ll*. 24-25.)

market. (Tr., p. 2104, *ll.* 1-4). This 90 megawatts of power is approximately ten percent (10%) of our system obligations. (Id.).

On redirect examination, Mr. Johnson explained that the costs associated with any short term purchases to satisfy this 90 megawatts of service obligations are already proformed into this base case by means of the power supply adjustment.

> Q: (Meyer) There was some discussion, Mr. Johnson, from the Commissioners about the 90 megawatts of system requirements that are currently being met by short-term purchases. Do you recall that?
>
> A: Yes, I do.
>
> Q: And these, the costs associated with any such short-term purchases to satisfy this 90 megawatts, are they or are they not already being proformed into this case by means of the power supply adjustment?
>
> A: Yes, they are proformed into this case. They are essentially purchased at the rate that comes out of our dispatch simulation model.
>
> Q: Okay.
>
> A: For each month.
>
> Q: So you're testifying then in order to satisfy that 90 megawatt deficiency with short-term purchases, the Company and, out of fairness, the staff for its part have both recommended a level of short-term purchase costs, correct?
>
> A: That's correct.
>
> Q: Okay. Now the PCA itself only serves to track any variation from those dollar per megawatt figures, correct?
>
> A: That is correct.
>
> Q: So if Mr. Norwood's adjustment, for example, of approximately $22 were adopted as part of the base case, if there were any variation up or down, it's that variation that would be tracked, correct?

A: That is correct.

(Tr., p. 2131, ln 13-p. 2132, ln. 16).

Moreover, Mr. Johnson testified that the Company will be resource deficient <u>even with</u> a 90 megawatt entitlement from BPA, with the result that the Company will still be purchasing on the short-term market. (Tr., p. 2133, *ll*. 1-12).[34]

Moreover, the accounting has been set up to immediately implement such a PCA, as testified to by Mr. Johnson:

> Q: (Meyer) Now you were also asked about, if I recall, whether the accounting had been worked through in order to implement this proposal, do you recall that?
>
> A: Yes, I do.
>
> Q: And was it your testimony that the accounting entries had been worked out and essentially are in place and ready to go in the event this Commission were to implement such a PCA tomorrow?
>
> A: Yes, we could implement this PCA tomorrow. We have everything in place. It would be the way we have been doing it in Idaho, so I mean literally within an hour after we knew the authorized level of purchases and sales, we would be ready to go with this PCA.

(Tr., p. 2133, ln. 24-p. 2134, ln. 12). Mr. Johnson also concluded that with what the Company has proposed, it would allow for <u>easy Commission review and monitoring</u>:

> Q: And with what the Company has proposed, does it allow for ongoing Commission review and monitoring?

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[34] Mr. Johnson for the Company also explained the impact of the stipulation on water year data that appears in Exhibit 740. As Mr. Johnson explained, it's simply a matter of "adjusting the purchases and sales every month to match up with what we agreed to in the stipulation." (Tr., p. 2130, *ll*. 23-25). According to Mr. Johnson, "What we are really tracking here are variations from not any number of years of water data, per se, but rather the authorized dollar levels of power costs that are being proformed into this base case." (Tr., p. 2133, *ll*. 18-23).

> A: Yes, every month we send in the PCA deferral along with all the calculations and all the back up and it can be audited at any time. And that's typically — that's what we have done in Idaho and it seemed to work well.

(Tr., p. 2134, *ll*. 13-19). Finally, if this Commission still has any residual concerns about the permanent adoption of a PCA, the Company offered to place such a PCA into effect on an interim basis for a three-year period. (Tr., p. 2134, *ll*. 20-24).

VI. COST OF CAPITAL AND FAIR RATE OF RETURN

A. Introduction

The Company proposes an overall rate of return on ratebase of 9.93%. This is based on a capital structure consisting of 47% debt, 4% preferred stock, 2% preferred securities, and 47% common equity. The Company's evidence supports a 12.25% cost of common equity, which is based on Dr. Avera's 12% recommended fair rate of return and a 25 basis-point premium to reward Avista's performance and efficiency. (See Exh. T-101, at p. 59, *ll*. 3-20; see also Exh. 102 (Schedule WEA-5).)

The Company's hypothetical capital structure consists of the average 1998 year-end capital structure ratios for a single-A rated proxy group of twelve companies primarily engaged in electric and gas utility operations. (Id. at p. 4, *ll*. 16 - p. 5, l. 7). As testified to by Company Witness Dr. Avera, the capital structure ratios maintained by other combination electric/gas utilities reflect the "capital markets' perceptions of the business risks faced by the industry and the mix of equity and debt required to accommodate these risks." (Id.) Furthermore, this hypothetical capital structure is consistent with historical trends, rating agency guidelines and the average capitalization authorized for combination utilities by other regulators. Additional arguments in favor of this capital structure include the fact that it "insulates ratepayers from the impact of financial policies specific to a particular company and avoids any distortions attributable to factors unrelated to providing utility service," as testified to by Dr. Avera. (Id.) Moreover, use of industry benchmarks permit a "proper matching" between the capital structure and investors' required rate of return for utilities and avoids the need to make other adjustments in order to account for differences and financial risk. (Id.)[35]

As concerns of cost of equity, Dr. Avera presents extensive testimony explaining why it is necessary to use a non-constant form of the DCF model in order to estimate the cost of equity, given the "dramatic structural change" occurring in the electric utility industry, and the fact that conventional applications of the constant growth DCF model do not capture investors' long-term expectations associated with increasing competition, diversification, and consolidation in the industry. (Id. at p. 5, l. 16 - p. 6, l. 3). Accordingly, Dr. Avera used a multi-stage DCF model which was applied to the same single-A rated proxy group of twelve combination electric/gas utilities used to develop the capital structure. This multi-stage analysis explicitly incorporated investors' expectations of varying growth rates over time and produced a cost of equity for the proxy group in the 10.9% to 11.9% range. Dr. Avera also used the "risk premium" analysis, for purposes of verification, which suggested an even higher cost of equity range for the group of single-A rated utilities of 11.9% to 12.9%. Based on the results of these analyses, Dr. Avera concluded that investors presently require a rate of return for a single-A rated combination electric/gas utility in the range of 11.25% to 12.25%. When one adds in necessary "flotation costs" of 25 basis points incurred in connection with past and future sales of securities, this produces a fair rate of return on equity for Avista of 11.5% to 12.5% — with a midpoint of 12.0%. (Id.)

[35] The costs of the debt component of this capital structure reflect imbedded interest rates, adjusted for the amortization of capitalized issuance costs over the term of the respective issues. Moreover, the preferred components of the capital structure were based on the dividend yield for each of Avista's preferred series.

Dr. Avera was careful to note that even this recommendation does not consider the higher investment risks associated with Avista's lack of a Power Cost Adjustment clause in Washington a point noted in the reports of credit rating agencies.[36] Nor does this recommendation otherwise incorporate the Company's recommended 25 basis point adder, as discussed by Company witness Dukich, in order to recognize management efficiencies and innovation.

B. Areas of Agreement/Disagreement with Staff and Intervenors

At the outset, the Company Staff and Intervenors agree on certain fundamental issues: All use Avista's embedded cost of debt and preferred stock; all estimate the cost of equity based on groups of comparable utilities rather than looking directly at Avista; and all apply a discounted cash flow (DCF) model to estimate the cost of equity for the comparable groups of utilities based on the fundamental premise that this will serve to "replicate investor's expectations" when they pay the current market price for utility common stocks. (Exh. T-135, p. 1, *ll*. 14-21).

The areas of disagreement, however, are significant: Staff and Intervenors use a simple, constant growth DCF model in order to capture investors' current expectations; the Company, on the other hand, firmly believes that a more sophisticated application of the DCF model, using a multi-stage analysis, is necessary to capture investor expectations, given the increased complexities of competition and deregulation. Because of difficulties associated with applying any form of DCF model, the Company looked to alternative methods (risk premium) to compare with the DCF results. Next, even though Staff and the Company agree that a 25 basis-point adjustment to cost of equity

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[36] Dr. Avera pointed out that most utilities, including a majority in his comparable group, have some form of power cost recovery mechanism. Moreover, no utility in the comparable group is as dependent as the Company on hydroelectric generation that is subject to swings beyond its control.

is necessary to recognize floatation costs, Intervenor Witness Hill would otherwise ignore these legitimate costs of raising capital.

Because the utility industry is in the midst of "dramatic structural change," including the introduction of retail competition, transmission unbundling, and deregulation of various segments of utility operations, it is no longer appropriate to use a single constant growth rate based on historical results or near term projections. As explained by Dr. Avera, investors no longer view past or near-term growth projections as indicative of the long-term growth rate in this "newly dynamic industry." (Id. at p. 2, l. 23 - p. 3, l. 20). Accordingly, a proxy for the growth rate must recognize investor's expectations of higher growth rates after utilities "weather the transition to a restructured and more competitive environment." (Id.) Therefore, it is time to embrace new ways to apply the DCF model in order to capture investor expectations during this transitional period. Even Dr. Lurito's proxy group is not immune from the dramatic changes sweeping the industry, as will be discussed below. Mr. Hill, on behalf of Public Counsel, for his part, stubbornly clings to an over-simplified constant growth method, ignoring the fact that investors' expectations are clearly evolving along with the utility industry.[37]

It is important for this Commission to recognize, in its cost of capital determination, the watershed developments in this dramatically changing industry. Only Dr. Avera's proposals for a multi-stage DCF cost of equity determination allows for the opportunity to reflect these developments. Moreover, Dr. Avera's results are supported, by way of a cross-check, by his risk premium analysis, which suggest an even higher cost of equity. When the dust settles, Dr. Avera captures in his testimony the significance of the Commission's determination:

[37] Indeed, in the Company's recently concluded Idaho general rate case, the Idaho Staff also relied on a multi-stage DCF model to estimate the cost of equity, departing from conventional application of a constant growth methodology. (Exh. T-135, p. 3, *ll*. 14-16).

> There is more at issue here than the professional pride of three rate of return witnesses — Dr. Lurito, Mr. Hill and myself. The signal sent by the WUTC in this important case will color investor perceptions of Avista far into the future and impact the Company's ability to attract capital in the dynamic environment ahead. No one knows what challenges or opportunities may ultimately face Avista and its customers; but it is clear that customers and the economy of Washington may be harmed if the provider of crucial energy infrastructure is financially impaired.

(Id. at p. 5, *ll*. 11-17).

Turning now to the adoption of an appropriate capital structure, the actual recommendations by Dr. Lurito and Mr. Hill are inconsistent even with their own proxy group of utilities that they used for purposes of estimating the cost of equity. The following table, excerpted from Dr. Avera's testimony, summarizes the common equity ratios derived from each witness's proxy group, and contrasts these results with the actual recommendations of each party:

	Common Equity Ratio
Dr. Lurito	
Proxy Group	43.4%
Proxy Group (ex. Short-term debt)	45.4%
Recommendation	42.0%
Mr. Hill	
Proxy Group	45.0%
Proxy Group (ex. Short-term debt)	49.0%
Recommendation	38.97%
Regulatory Research Assoc. Authorized	
Electric (1994-98)	46.15%
Gas (1994-98)	48.61%
Avera	
Proxy Group	47.0%
Recommendation	47.0%

(Exh. T-135, p. 4, *ll*. 1-15). As you can see from this excerpted table, while Dr. Lurito reported an average equity ratio for his own proxy group of 44.4% (later revised to 43.4%), he nevertheless recommended a capital structure which only incorporated a 42% equity ratio while still arguing that his comparable group is sheltered from the uncertainties "buffeting Avista and other utilities". (Id. at p. 4, *ll*. 16-20). Even more dramatic is Mr. Hill's recommended capital structure of only 38.97% equity in the face of his own comparable proxy group which was in the range of 45% to 49%. (Id. at p. 4, *ll*. 21-30). Furthermore, both Dr. Lurito and Mr. Hill erroneously include temporary short term debt as a component of their capital structures, even though this debt is not a permanent source of capital used to finance long term assets. When one properly excludes short term debt, Staff's proxy group common equity ratio is 45.4% and Public Counsel's proxy group common equity ratio is 49%. For purposes of comparison, Dr. Avera's recommendation of 47%, on the other hand, was clearly in line with the results of his proxy group (also 47%).

Finally, this table includes the authorized common equity ratios from a much larger database consisting of electric companies (1994-1998) and gas companies (1994-1998), as compiled by Regulatory Research Associates, which results reveal an average authorized common equity ratio of 46.15% (for electric) and 48.61% (for gas). (Id. at p. 4, *ll*. 10-12). Clearly, therefore, these results are in line with Dr. Avera's recommendation.[38]

C. Additional Criticisms of Staff's Case

With respect to cost of equity, Dr. Lurito recommended a 10.40% return on equity, based solely on the results of a constant growth DCF model applied to a group of 5 other utilities. (Exh. T-135, at p. 6, *ll*. 3-20). For the six-month period October 1999 through March 2000, he calculated an average historical dividend yield for a proxy group of five utilities. He then reviewed five and

[38] Furthermore, as will be discussed infra, Dr. Lurito and Mr. Hill used capital structures more appropriate to a utility with less business risk, given the presence of a cost adjustment mechanism for several of the proxy group utilities; Avista does not yet have such an approved mechanism in this jurisdiction. (Id. at p. 4, *ll*. 27-30).

ten-year historical growth rates and earnings per share, dividends per share and book value per share. He concluded that the future growth rate rational investors can expect is 2.5% to 2.7%. (Exh. T-632, p. 21). After increasing the historical dividend yield to reflect one-half year's growth, Dr. Lurito concluded that the cost of equity for his group of five utilities fell in the 10.02% to 10.23% range, selecting 10.15% as a recommended cost of equity. He then added a 25 basis point allowance for equity floatation costs, producing a recommended return on equity of 10.4%. (Id. at p. 6, *ll*. 3-20).

Dr. Lurito proceeds on a fundamentally flawed premise — namely that his group of five utilities have stable operations that are not otherwise "exposed to the same major changes sweeping the electric power industry," as testified to by Dr. Avera. (Exh. T-135, at p. 7, *ll*. 2-5). Dr. Lurito, in his testimony, even concedes that it is:

> . . . Well known, [that] the electric/gas industry has undergone and will likely continue to undergo major changes, such as merger/acquisition activities, diversification into non-regulated businesses, and retail consumer choice of service provider.

(Exh. T-632, p. 8). He even conceded at page 8 of his direct testimony (T-632) that, because of these changes "it becomes a difficult task for the analyst to assess investor expectations . . . especially for those utilities that have recently experienced, or are currently experiencing, many of the changes already enumerated." (Id.) He further concedes, at pages 17-18 of his direct testimony, that "multi-stage DCF models were introduced in an attempt to recognize that many utilities' future dividend growth experience would likely diverge from past experience." He then seeks to sidestep the limitations of a constant growth DCF model by selecting utilities which he believes have a "stable past and future" in order to continue to apply a single stage DCF analysis. Simply put, he believes his group of five companies are, in a sense, immune from many of the changes that dramatically impact the industry.

In fact, as explained by Dr. Avera, the five companies in Mr. Lurito's group "are impacted by largely the same fundamental challenges posed for other utilities, including the introduction of wholesale and retail competition, diversification into non-regulated business lines, changing dividend policies, asset divestitures, and the prospects for continued mergers and acquisitions." (Exh. T-135, p. 9, *ll*. 1-6). Accordingly, Dr. Lurito's analysis gives "no consideration to other factors investors might evaluate in forming the growth expectations, e.g., deregulation and competition, or that the upheaval in the electric power industry might violate the steady-state assumptions underlying the constant growth DCF method." (Id. at p. 9, *ll*. 6-12).

Dr. Avera explains how companies in Dr. Lurito's group have and will continue to be impacted by challenges facing the industry at large. By way of example, CH Energy Group, Inc. and RGS Energy Group, Inc., which were included in Dr. Lurito's analysis, are subject to the terms of industry restructuring in New York which includes the establishment of an independent system operator (ISO) and the opening of retail markets to competition by June of 2001. In this regard, CH Energy will begin auctioning its non-nuclear generating capacity. CH Energy is also formulating a new holding company structure, as it increases its focus on non-utility activities, and devotes more resources to investment in the competitive sector.

Simply put, Dr. Lurito's contention that his selection criteria results in companies with "stable pasts and futures" (see Exh. T-632, p. 18) doesn't wash. Each of the five utilities used by Dr. Lorito are exposed to the same changes confronting the electric industry in general as described in detail by Dr. Avera. Accordingly, investors are not likely to ignore changes when formulating their growth expectations even for these five utilities in Dr. Lurito's group.

As a reality check, Dr. Avera compared Dr. Lurito's cost of equity estimates for members of his group with yields on single-A public utility bonds. (Id. at p. 15, *ll*. 3-16). Single-A public utility bonds yielded an average of 8.29% in April of 2000 and reached approximately 8.8% by May of 2000, prompting Dr. Avera to observe that: ". . .it is inconceivable that investors' required rate of return on equity, the most junior and risky of the utility's securities, would not significantly exceed the single-digit levels." (Id.) Yet, none of Dr. Lurito's individual equity estimates for CH Energy or United Illuminating exceeded 10%; indeed his analysis indicated that the average cost of equity for these two firms using projected growth rates was 7.99% and 8.50%, respectively. Interestingly enough, over one-quarter of Dr. Lurito's cost of equity estimates actually fall below the 8.8% current yield on single-A public utility bonds. (Id.)[39]

Nor does Dr. Lurito's focus on market-to-book ratios in setting the allowed rate of return on equity survive scrutiny. In fact, as explained by Dr. Avera, these ratios are impacted by other external factors unrelated to utility operations — e.g. diversification into non-regulated activities may cause the market price of a utility stock to deviate significantly from its book value. (Id. at p. 17, *ll*. 5-7).[40] As observed by Dr. Avera, while Dr. Lurito may believe that investors expect the utilities in his group to earn 11.3% in common equity, he suggests that regulators should only allow them no more than 10.17%. Accordingly, with market-to-book ratios above 1.0 times, Dr. Lurito apparently believes that, unless book value grows rapidly, regulators should estimate equity returns that will cause share prices to fall. (Id. at p. 17, *ll*. 19-23).[41]

When all is said and done, the end result of Dr. Lurito's analysis fails to properly reflect the impact of major structural changes in the industry and the utilities' transition to competition, as such

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[39] If one were to exclude the "illogical values" for CH Energy and United Illuminating, the resulting average cost of equity estimates for the remaining companies in Dr. Lurito's group would be approximately 11.0%. (See Exh. T-135, p. 15, l. 19 - p. 16, l. 3).

[40] There is simply no sound basis for suggesting that regulators should set the required rate of return to produce a market-to-book value of approximately 1.0. As explained by Dr. Roger A. Morin in Regulatory Finance: Utilities Cost of Capital:

> The stock price is set by the market, not by regulators. The M/B ratio is the end result of regulation, and not its starting point. The view that regulators should set an allowed rate of return so as to produce a M/B of 1.0, presumes that investors are masochistic. They commit capital to a utility with a M/B in excess of 1.0, knowing full well that they will be inflicted a capital loss by regulators. This is not a realistic or accurate view of regulation. (Pg. 265).

(Exh. T-135, p. 17, *ll*. 13-18).

[41] The "nonsensical" result produced by this thinking was described by Dr. Avera on rebuttal. (Exh. T-135, p. 17, l. 24 - p. 18, l. 2). In DCF theory, a drop in stock prices means negative growth and a negative growth rate implies a DCF cost of equity for utilities less than their dividend yields. (Id.)

might impact the traditional constant growth DCF analysis.[42] The five companies in his proxy group are subject to the same changes and uncertainties confronting the utility industry in general; accordingly historical and near-term growth rates simply do not accurately reflect the long run growth expectations that investors are currently incorporating into stock prices. In the final analysis, Dr. Lurito's analysis "tells us nothing about the rate of return investors require from an investment in common stock of utilities." (Id.)

Staff Witness Lurito, while noting that Avista's consolidated capital structure at year-end 1999 consisted of 43.2% common equity (after adjusting for the subsequent conversion of convertible preferred stock), nevertheless, adjusted the equity ratio downward of 42% given what he perceived as the "relatively low risk of Avista's electric and gas operations." (Exh. T-632, p. 26). This is below the average common equity ratio for the five companies that he relied upon to establish the cost of equity, which was 44.4% (subsequently revised to 43.4%). Even though his recommended capital structure implies greater financial leverage and hence, greater investment risk, he failed to make a corresponding upward adjustment to the cost of equity — again based on the same five companies. (Exh. T-135, p. 19, *ll*. 8-15).

In the final analysis, and given the changes confronting electric utilities — including those in Mr. Lurito's proxy group — the assumptions underlying Dr. Avera's application of the multi-stage DCF model "are certainly more plausible 'than the steady-state' presumed by the constant growth model Dr. Lurito used." (Id. at p. 23, *ll*. 8-11). Dr. Lurito simply takes "refuge" in the simplifying assumptions of his constant growth model in order to sidestep the complexities inherent in any proper estimation of the current cost of equity. (Id.)

[42] The last proceeding in which Dr. Lurito testified to cost of capital was approximately 7 years ago in Docket No. UE-921262, involving Puget Sound Power & Light, as shown in Exhibit 633. In the last 7 years since he testified on electric cost of capital matters, Dr. Lurito agreed that taken as a whole, the electric industry has undergone some rather significant changes. (Tr., p. 1780, l. 27 - p. 1782, l. 17.)

Nor is it correct to infer, as does Dr. Lurito that higher long-term growth rate expectations are incompatible with what he assumes to be a mature state of the electric power industry. While he incorrectly characterizes utilities as being in a "mature industry," he also admits that they have entered a "new era." (See Exh. T-632,p. 17, L. 15). This "new era" finds the utility industry diversifying into the competitive arena and expanding investments in non-regulated enterprises, in short, looking for opportunities for higher long term growth. Investors consider these other growth prospects when evaluating a utility's common stock and should not be ignored, as Dr. Lurito does, when implementing the DCF model.

Finally, Dr. Avera also took issue with Dr. Lurito's attempt to update the debt numbers within the capital structure. First of all, when Dr. Lurito proformed the debt cost into the capital structure, he did not change the amount of the preferred stock in the capital structure, so he is, in essence, double counting the preferred stock. He's saying the preferred stock that it is in the capital structure now will go down to debt, but he believes it will be replaced by other preferred stock. (Tr., p. 1827, *ll*. 9-22).

Moreover, Dr. Lurito proposed to use a projected cost for preferred stock and a projected cost for short-term debt, which Dr. Avera took strong exception to:

> Dr. Lurito believes that Mr. Federal Reserve is going to change his policy and do something differently than he has been doing about raising interest rates. I don't know if Dr. Lurito is right or not. If Dr. Lurito has the capability of predicting federal reserve policy, there are rich rewards available for him on Wall Street. I don't think this Commission should set the short-term rate based on a prediction of what short-term rates are going to do in the future.
>
> I think that's a substantive change. That is not what I did in my testimony. I based short-term rates on what they actually were. My update updated based on new experience through March of 2000. Dr. Lurito has embodied in this change a prediction of what the Company would get as a yield on short-term debt in the future reflecting a change in federal reserve policy. . . that is a projection, not an embedded cost.

(Tr., p. 1828, *ll*. 4-24).

D. Recommendations of Public Counsel Are Similarly Flawed

On behalf of Public Counsel, Mr. Hill proposed an overall rate of return for Avista of 8.82% He combined a rate of return on equity of 10.875% with a capital structure composed of 38.97% common equity. (Exh. T-135, p. 28, *ll*. 12-17). In order to arrive at his cost of equity recommendation, Mr. Hill applied a constant growth DCF model to a group of eight other electric and gas utilities.[43] Mr. Hill concluded that the cost of equity for his comparable group was in the range of 10.50% to 11.25%, from which he selected the midpoint of 10.875%. Interestingly enough, Dr. Hill did not incorporate an allowance for floatation costs into his estimated rate of return on equity, in contrast to Staff's recommendation which did provide for such an allowance.

With regard to capital structure, Mr. Hill developed a hypothetical "utility-only" capital structure, arrived at by subtracting virtually all of Avista's investment in non-utility businesses from the equity component of the consolidated capital structure as of December 31, 1999. This hypothetical capital structure of 38.97% is inconsistent with the capital structures maintained by his own comparable group of utilities used for establishing cost of equity (49%). Even though Mr. Hill's hypothetical capital structure, therefore, implies far greater financial leverage than is maintained by his proxy group, he failed to make a corresponding upward adjustment to his cost of equity to recognize this higher risk, as noted by Company Witness Avera. (Exh. T-135, p. 29, l. 21 - p. 30, l. 2).

Mr. Hill's analysis suffers from the same flawed premise: He assumes that conventional, constant growth assumptions reflect how investors are currently valuing utility common stocks. In fact, the historical growth rates examined by Mr. Hill provide "little guidance to future results and

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[43] He then used three other methods (earnings-price ratio; market-to-book ratio; and two applications of the Capital Asset Pricing Model (CAPM)). (Exh. T-135, p. 28, l. 22 - p. 29, l. 2).

near-term projections do not capture expectations beyond the transition to competition," as observed by Dr. Avera. (Id. at p. 29, *ll*. 14-21).[44]

Nor does the fact that bond yields are relatively low by historical standards suggest that Mr. Hill's recommended 10.875% return on equity is reasonable. In fact, as testified to by Dr. Avera, there is substantial evidence that equity risk premiums tend to move inversely with interest rates. In any rate, the last time this Commission established a rate of return on equity for Avista was in March of 1987, when the Commission authorized 12.9% in Docket No. U-86-99. The average yield on single-A public utility bonds have fallen from approximately 8.9% to an average of 8.3% since that time. Even if we were to ignore the inverse relationship between equity risk premiums and interest rates, simply adjusting the WUTC's 12.9% return on equity by the full 60-basis-point change in bond yields would imply a current cost of equity of 12.3%, as testified by Dr. Avera. (Exh. T-135, p. 31, l. 6-24). Moreover, with the Federal Reserve's decision on May 16, 2000, to raise the Federal Funds rate to 6.5%, it is now equal to the rate cited by Mr. Hill and even higher than the average of 6.13% which prevailed in March of 1987 when the WUTC issued its decision in Docket No. U-86-99. (Id.)

More importantly, it is well to challenge the "steady state" assumptions of the constant growth DCF model relied upon by both Mr. Hill and Dr. Lurito. In the dramatically changing utility environment, they no longer mirror investor expectations. For example, a February 3, 2000 Goldman Sachs publication examines investors' expectations of higher long-term growth from utilities:

> We believe that accelerating growth rates, improving management decision making, structural changes, accelerating LBO activity, and incremental recognition of technology investments will drive the prices of many power and utility stocks . . . EPS growth rates for select power and utility stocks are accelerating. (Pg. 3)

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[44] Dr. Avera noted that in a recent report published by the Association for Investment Management and Research, with over 40,000 worldwide members in the investment profession, that the conclusion reached was that "the basics of the industry are no longer valid" and that "new analytical tools" were required to analyze and value electric utility securities. (Exh. T-135, p. 29, *ll*. 17-21).

(Exh. T-135, p. 33, *ll*. 17-27). Moreover, in A.G. Edwards' January 14, 2000 Electric Utility Stock Update, it was noted that deregulation is spurring companies to develop new businesses and provide customers with new services, which factors "are expected to lead to EPS growth in the 4% to 6% range for most electric utilities over the next several years." (Id. at p. 33, *ll*. 1-14) Simply combining this 4% to 6% near term growth rate range with a 7.83% average dividend yield for Mr. Hill's own proxy group of utilities would result in a cost of equity range of 11.83% to 13.83%.[45] (Id.)

It is also well to note that increased reliance being placed on methods other than the constant growth DCF model by regulatory commissions. In his rebuttal testimony, Dr. Avera cited a few recent examples. The Public Utility Commission of Texas in Docket No. 9945 involving El Paso Electric Company found that "under present market and utility industry conditions, the constant discounted cash flow model does not provide reliable results." (Exh. T-135, at 56, *ll*. 10-18). The same Commission, in Docket No. 12852, involving the cost of equity for Energy Gulf States again determined that "the cost of equity" is properly determined using a non-constant discounted cash flow (DCF) and "risk premium analysis." (Id.) Elsewhere, for example, in Florida the Public Service Commission concluded in an April 29, 1998, decision that continued reliance on standard or constant DCF techniques is misplaced:

> Upon consideration, we find that the multi-stage DCF model employed by AT&T/MCI witness Cornell is superior to the single-stage DCF model used by Bell South witness Billingsley for estimating the cost of capital for Bell South. Witness Cornell testifies that the form of DCF model he uses is well-supported in the financial community. (Page 22).

(Exh. T-135, p. 57, *ll*. 4-8). The growing acceptance of the use of a multi-stage DCF analysis by state regulators reflects what the investment community already knows: That utilities are in the

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[45] Mr. Hill presents a similar calculation on page 6, lines 3-11 of his direct based on a 1999 A.G. Edwards publication referencing integrated gas utilities. Hence, the same calculation based on the same brokerage firm, but using a more recent analysis for the electric utility industry, shows the unreasonableness of Mr. Hill's end result.

midst of dramatic structural change occurring throughout the industry and that investor's expectations over the long run cannot be governed by historic and near term projections.

Nor does Mr. Hill's reference to market-to-book ratios for utility stocks demonstrate the reasonableness of his recommended cost of equity. As was true with Dr. Lurito's analysis, with market-to-book ratios for utilities above 1.0 times, Mr. Hill's recommendation simply implies a "sharp drop in share prices and capital losses for investors." Stated differently, under Mr. Hill's constant growth DCF theory, this would "imply that investors are anticipating negative growth, with their cost of equity falling below utilities' dividend yields," as explained by Dr. Avera. (Id., p. 34, *ll*. 4-8).

In the final analysis, it does not matter whether Mr. Hill chooses to believe an acceleration of long-term growth is achievable; what matters is that this is the expectation that investors have embodied into current market prices and are the only growth rates relevant to the DCF model. (Id. at p. 33, *ll*. 25-27). Mr. Hill notes that his model assumes a "steady state environment": "the payout ratio and expected return are constant and the earnings, dividends, book value and stock price all grow at the same rate, forever." (Exh. T-622, p. 25). As explained by Dr. Avera, however, these "steady state" assumptions are no longer meaningful in an industry undergoing major structural change. We should not simply assume away the dramatic changes that challenge this "steady state" assumption, simply in order to embrace the convenient use of a constant growth DCF model.

Nor are Mr. Hill's other analyses, such as use of CAPM and earnings-price ratio analyses, appropriately performed. For example, his application of the CAPM is "biased downward" for two reasons. First of all, he used short-term T-bill rates as the risk-free rate of interest. Because common stock is a permanent source of capital, as explained by Dr. Avera, the pertinent risk-free rate for use in the CAPM when estimating the cost of equity is the yield on long-term U.S. Treasury Bonds — not the yield on short-term T-bills. (Id. at 42, *ll*. 10-24). Secondly, the reported beta values for the firms in Mr. Hill's utility group are calculated based on historical information; accordingly, they fail to accurately reflect the greater uncertainty utilities now face as the utility "transitions to competition." (Id. at 43, *ll*. 1-13). Furthermore, in connection with his modified earnings-price ratio (MEPR) analysis, there is, in the words of Dr. Avera, "absolutely no theoretical justification for Mr. Hill's averaging the MEPR with a rate of return on book equity, either current or expected, as he did in his Schedule 10." (Id. at 43, *ll*. 16-23). Finally, his market-to-book ratio analysis does not provide any new or additional information as to the rate of return required by investors. This method, as acknowledged by Mr. Hill himself, is "derived algebraically from the DCF model and, therefore, cannot be considered a strictly independent check of that method." (Exh. T-622, p. 42). With regard to common stock flotation costs, Mr. Hill does not recognize the need for any adjustment to his return on equity. In so doing, he ignores the fact that flotation costs are a necessary expense of obtaining equity capital and, irrespective of future financing plans, a flotation cost adjustment is necessary to compensate for flotation costs incurred in connection with past issuances of common stock. Even Dr. Lurito, in his testimony, acknowledged the need for recovery of flotation costs:

> According to Avista Corporation's 1999 10-K Report, Avista Utilities will generate sufficient funds internally through 2002 to preclude the need for external financing. However, it is necessary to allow Avista Utilities to recover in rates an amount sufficient to allow Avista Corporation to recoup sunk financing costs related to past common stock sales. (Exh. T-632, p. 25).

Accordingly, Staff Witness Lurito agreed that it was appropriate to adjust the cost of equity for Avista by twenty-five basis points to account for flotation costs.[46]

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[46] The necessity of an adjustment for past flotation costs has also been recognized in the literature. In Roger A. Morin's Regulatory Finance: Utilities' Cost of Capital he concludes:

> This argument [that flotation costs should only be made in the year in which the sales of securities occurs] implies that the company has already been compensated for these costs and/or the initial contributed capital was obtained freely, devoid of any flotation costs, which is an unlikely assumption, and certainly not applicable to most utilities. . . the flotation cost adjustment cannot be strictly forward-looking unless all past flotation costs associated with past issues had been recovered. (Page 175).

(See also Exh. T-135, p. 47, *ll*. 1-18).

Turning now to Mr. Hill's recommended capital structure, as indicated above, he derived his "utility-only" capital structure by subtracting Avista's entire net investment in non-utility businesses from the common equity outstanding as of December 31, 1999. Dr. Avera explained why, in the first instance, Mr. Hill's capital structure does not represent the actual capitalization even of the regulated utility operations. (Exh. T-135, p. 48, *ll*. 1-7). Because Avista does not have a holding company structure, a separate balance sheet is not maintained for Avista's regulated activities, with the capital of its various business lines being provided from general corporate funds. Accordingly, Mr. Hill's capitalization is derived based on a <u>hypothetical</u> capital structure that "arbitrarily assumes Avista's non-utility activities are financed with 100% common equity." (<u>Id</u>. at 48, *ll*. 6-7). As explained by Dr. Avera, it is simply not reasonable to assume a capital structure consisting of 100% equity for non-utility businesses. As observed by Dr. Avera, firms in the competitive sector are not financed with 100% equity. As reported in Value Line (February 4, 2000), the 827 industrial, retail, and transportation companies included in its Industrial Composite maintained a capital structure consisting of approximately 39% long-term debt and 61% common equity. (<u>Id</u>. at p. 48, *ll*. 11-14). Stated simply, any adjustment of consolidated capitalization to arrive at a hypothetical "utility only" capital structure is "fraught with difficulties and problematic at best," as testified to by Dr. Avera. It was for that reason that he recommended a capital structure based on the capitalization for a proxy group of electric and gas utilities.

The most significant point is this: the average common equity ratios for the group of utilities that Mr. Hill believes are similar in risk to Avista, and which were used by him for purposes for a cost of equity determination, range from 45% to 49%, (depending on whether short-term debt is included or excluded from permanent capital). While he relies on this group for purposes of establishing the cost of equity, he conveniently ignores the capital structures maintained by this "similar group" when it comes to the issue of capital structure. <u>If in fact he is allowed to posit a 39% common equity ratio instead of an equity ratio of between 45% and 49%, and given the increased</u>

financial risk that this leverage assumes, he should have substantially adjusted upward his recommended cost of equity on this same group. This he did not do.

Mr. Hill even concedes, in his testimony, at page 50 (Exh. T-622) that "due to the differences in common equity ratio between Avista and my sample group of firms, the Company could be said to carry somewhat higher financial risk." Yet, does not adjust upward the implied cost of equity based on his sample group of firms to account for this higher financial risk. This Commission in its Eleventh Supplemental Order, dated September 21, 1993, in a Puget Sound Energy case (Docket Nos. UE-920433, UE-920499, UE-921262) recognized the inter-relationship between capital structure and cost of equity, when it observed that the "cost of equity and capital structure decisions must be made together. . ." (Id. at 28).[47] Mr. Hill acknowledges that the cost of equity in capital structure decisions should be made together when the Commission issues its decision. (Tr., p. 1706, l. 25 - p. 1707, l. 2.)

Mr. Hill even concedes that the absence of a PCA also implies greater risk for Avista, when he observes that "there may be some risk-inducing aspect relating to the fact that a few of the firms included in my sample group do have power adjustment clauses." (Exh. T-622, p. 51).[48] Mr. Hill agrees that the absence of the PCA implies greater risk for Avista, all else being equal. (Tr., p. 1707, *ll*. 7-10.) Moreover, the utilities in Mr. Hill's group do not rely significantly on hydro-generation, enabling them to better mitigate the risks of fluctuating power costs. Avista, for its part, remains exposed to the impact of year-to-year fluctuations in water conditions. (Id. at 52, *ll*. 7-20).

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[47] In that proceeding, the Commission accepted an increase in the equity component of its capital structure to 45%, finding this to be neither "an inappropriate or imprudent capital structure." (Id. at 31).

[48] A review of the 1999 Form 10K Reports for the utilities in Mr. Hill's group indicates that four of the eight companies in his group have some form of adjustment clauses in place to accommodate changes in fuel or purchase power costs; of the remaining four, three utilities have either undergone comprehensive industry restructuring or have incentive regulation plans in place. (Exh. T-135, p. 51, l. 29 - p. 52, l. 6).

Mr. Hill concedes that the utilities within his sample group do not rely as heavily on hydro-generation as does Avista. (Tr., p. 1708, *ll*. 1-3.) He also agrees that Avista, for its part, remains exposed to the impact of year-to-year fluctuation of water conditions, absent a PCA. (Tr., p. 1708, *ll*. 4-7.) He agrees that from an investor perspective, absent a PCA, investors perceive an increased business risk surrounding the volatility in the energy marketplace. (Tr., p. 1708, l. 24 - p. 1709, l. 6.) Mr. Hill, though, was largely unfamiliar with the delivery points of Mid-C or COB, and had not read, at all, Mr. Norwood's rebuttal testimony concerning a variety of power supply issues, including pricing and volatility. (Tr., p. 1709, l. 24 - p. 1710, l. 13.)

Nor is it appropriate to include short-term debt in the utility's capital structure as both Dr. Lurito and Mr. Hill do. Where short-term debt is temporary and is not used to finance on a permanent basis investment in plant and equipment, it should be excluded when calculating the overall rate of return. Short term debt is used by Avista to meet seasonal working capital needs and is not used as a permanent basis to finance capital improvements. The mere fact that Avista had short-term debt as of December 31, 1999, does not, in any way, suggest that it should be included in Avista's consolidated capital structure. Avista's short term debt, as explained by Dr. Avera, fluctuates depending on seasonal or other operating requirements. For the thirteen-month period ending December 1999, Avista's month-end balance of short-term debt outstanding fluctuated between zero (December 1998 and April 1999) and $127.4 million (August 1999). Dr. Avera noted that "these fluctuations, and the fact that there was <u>no</u> short-term debt outstanding in two of the months during this period, evidences that the use of short-term debt by Avista is temporary." (<u>Id</u>. at 53, *ll*. 15-21). Therefore, the use of year-end figures by Dr. Lurito "grossly overstates" the amount of short-term debt used by Avista.[49]

[49] Dr. Lurito's use of year-end figures grossly overstates the amount of short-term debt used by Avista. Over the six quarters under December 31, 1999, short-term debt constituted only 4% of Avista's consolidated capital structure — as compared with the 8.5% recommended by Dr. Lurito. (Exh. T-135, p. 54, *ll*. 1-5).

E. Summary and Conclusions

Mr. Jon E. Eliassen, Senior Vice President and Chief Financial Officer of Avista Corporation also provided rebuttal testimony (Exh. T-520), in which he described the changes occurring in the utility industry. He appropriately notes that, while the industry has undergone and is continuing to experience significant changes that "change investor perceptions and expectations about the industry," Staff Witness Lurito and Public Counsel Witness Hill have "failed to draw the appropriate conclusions about the effect of these developments on our cost of capital." (Id. at p. 2, *ll*. 21-24). Absent a PCA mechanism, investors perceive a substantial increase in business risk surrounding the volatility in the energy market place. Exposure to this power price variability has become a significant risk for electric utilities as testified to by Mr. Eliassen. (Id. at p. 2, l. 27 - p. 3, l. 8). Indeed, the cost of short-term purchased power has increased dramatically over the past four years (by over 110%); in addition, the "extreme volatility" in short term prices such as those experienced in 2000 have had a significant impact on costs and operating results for the Company's electric utility operations. Mr. Eliassen was quite right in concluding that "the increased energy price volatility will result in investors perceiving higher risks and requiring higher returns." (Id.)

Proposals of Staff and Intervenors also will have a significant negative impact on cash flow. Staff's proposal with regard to the financial restructuring of the Portland General capacity contract will have a significant and immediate negative impact on cash requirements of at least $56 million, as testified to by Mr. Eliassen and would increase the amount of new financing that would be required over the next few years. (Id. at p. 3, *ll*. 11-22). Moreover, Staff's proposal would suggest the elimination of some of the lowest cost financing that we currently have, by "paying off" the lease on the Rathdrum generating plant; accordingly, not only would the Company experience reduced future cash flows, but we would have to borrow the cash at a higher interest rate than we currently have "locked-in" over the next five years, as explained by Mr. Eliassen. (Id.) Essentially, the effect of Staff's proposal is to "manage the financial decision-making process of the Company" —

something that would be viewed, in Mr. Eliassen's belief, very negatively by investors, our banks and the credit rating agencies." (Id. at p. 4, *ll*. 1-3).

Staff and Intervenor's proposed hypothetical capital structures are also troublesome. When one examines the utility capital structures over the 10 year period from 1989-1998, one notes a general trend of increasing common equity ratios: actual data on the average common equity ratio as reported by Moody's has increased from 41.3% in 1989 to 45.2% in 1998. (Id. at p. 4, *ll*. 15-17, see also Exh. 521). This is not surprising, inasmuch as when earnings and cash flows become more volatile and uncertain, business risk is increasing and it is necessary to adjust the debt and equity ratios to maintain investment grade credit ratings, as explained by Mr. Eliassen. (Exh. T-520, p. 5, *ll*. 1-4). And, it remains important for Avista to maintain investment grade credit ratings so it can gain access to capital at reasonable costs. The capital expenditures for the 10 year period from 1990-1999 totaled $988.5 million (representing an average of nearly $100 million annually). Utility capital expenditures are expected to be $320 million over the next three years. In addition, as explained by Mr. Eliassen, there will also be debt and preferred stock maturities of $137 million over the next three years. When compared with internal cash generated by utility operations of $334 million for this same period, Avista has $123 million less than its total requirements, thereby necessitating access to capital at reasonable costs. (Id. at p. 6, *ll*. 1-7).

However, the capital structures proposed by Dr. Lurito and Mr. Hill are problematic in that they can put downward pressure on the Company's credit rating and reduce the Company's flexibility to finance. Dr. Lurito's debt ratio of 48.5% and Mr. Hill's recommended debt ratio of 50.58% would be within the "BBB" rating category under S&P guidelines. According to Mr. Eliassen, while this is an investment grade level, it is "not a preferable rating level over the long term;" a higher rating "is desirable to provide financing flexibility." (Id. at p. 6, *ll*. 10-16).

Moreover, neither Dr. Lurito nor Mr. Hill have examined the debt versus equity treatment afforded by rating agencies for various classes of preferred stock. Mr. Eliassen explained the equity credit that Standard & Poor's assigns to various hybrid securities that feature both debt and equity characteristics, and when these factors are applied to Avista's preferred securities, the result would be to increase the debt ratio by approximately 6 percentage points. This would produce debt ratios of 54.5% and 56.58% based on the capital structures recommended by Dr. Lurito and Mr. Hill. In the words of Mr. Eliassen, "debt at this level would equate to a rating in the bottom of the 'BBB' category or the top of the 'BB' category based on S&P's guidelines." (Id. at p. 7, *ll*. 15-19).

Mr. Eliassen also takes issue with the treatment afforded short-term debt by Dr. Lurito and Mr. Hill. Simply put, it does not make sense to include short-term debt in a capital structure intended to finance long-lived assets such as those in a utility rate base. Short-term debt is, after all, not a permanent source of capital and is usually outstanding for less than 30 days. The variability in levels of short term debt is amply demonstrated by Mr. Eliassen's Exhibit 521, which shows several points at which there was no short term debt outstanding.[50]

In summary, an appropriate debt ratio, in Mr. Eliassen's view, is in the range of 45% to 50%, including the debt equivalent portion of preferred stock. What the Company has actually proposed by way of a debt ratio of 47% is within this range.

Mr. Hill's reliance on the 1999 year-end equity ratio is misplaced, however. As explained by Mr. Eliassen there were "two unusual financial activities during 1998 and 1999 that caused the ratio to be below our historical levels." (Id. at p. 10, *ll*. 1-11). The first was the issuance of convertible preferred stock in 1998 which was mandatorily convertible to common stock within 3 years — and in fact was converted in early 2000. As such, it is appropriately included in common equity. The other activity consisted of the buyback of common shares of the Company at a time

[50] If, however, short-term borrowings were to be included in capital structure, an average balance of short term debt reflecting our actual average balance over the past 4 years would be more appropriate. As shown on page 2 of Exhibit 521, that amount is $45 million. Moreover, the proper cost of this short-term debt should be based on the most current actual rates the Company is experiencing, which are 7.49% as of May 26, 2000, as shown on page 2 of Exhibit 521. Accordingly, if any average level of short-term debt is to be included in capital structure, a reasonable cost should be at least 7%. More recent figures reflect the fact that short-term debt costs have continued to move up since December of 1999 as demonstrated on page 3 of Exhibit 521.

when the shares were undervalued, in order to allow the Company to reissue them at a later date when the stock price reflected a more reasonable value. The Company repurchased 9.13% or 5.1 million shares during 1999, which reduced the common equity balance by $87.9 million. It is important to remember that the impact on the equity ratio from the repurchase was a <u>temporary decrease</u> in the equity ratio of approximately 5.8 percentage points. If one were to add the impact of the stock buyback and the convertible preferred stock back to the actual common equity ratio as of December 31, 1999 <u>the common equity ratio would have been 49.0%</u>. This is <u>higher than</u> the equity ratio actually proposed by the Company in this case. (<u>Id</u>. at p. 10, *ll*. 14-21).[51]

Therefore, Mr. Eliassen concluded that an appropriate capital structure would consist of 45% to 50% common equity, 4% to 7% preferred equity (as adjusted for the appropriate equity credit), and 45% to 50% debt (adjusted for the debt equivalent of preferred securities), all of which would allow the Company to "finance its utility operations at a reasonable cost." (<u>Id</u>. at p. 11, *ll*. 16-22). The capital structure proposed by Company Witness Avera falls within these ranges.

Finally, with respect to levels of common equity returns, it is well to remember that even the evidence presented by Dr. Lurito with respect to average allowed return on equities for utilities is 11.4% and actual annual earned returns on equity in 1999 for those companies were 11.3%. Mr. Hill, on behalf of Public Counsel, presents evidence for another similar group of companies showing an average cost of equity of approximately 11.3% (excluding Alliant Energy which seems to be an unusual case) with the average expected earned return for 2000 to be 12.06%. This should be compared with the group of companies in Dr. Avera's analysis that shows an average allowed return on equity of 11.7%. This prompted Mr. Eliassen to observe that "the data seems quite consistent to me:"

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[51] Attesting to the fact that the Company actually intends to issue new common stock, was the application filed with this Commission in May of 2000 to issue 3.7 million new common shares, which was authorized by Order of this Commission on May 30, 2000. Assuming, for example, the issuance of just 1.5 million new shares at an assumed price of $25, the resulting equity increase of 37 million would increase the common equity ratio by approximately 2%. (<u>Id</u>. at p. 11, *ll*. 1-9).

> If these are indeed comparable companies as asserted by all the witnesses, then the return on equity (excluding any adjustments related to good management) should be in the 11.3% to 11.7% range. Adding in adjustments for financing costs and management effectiveness results in a range of 11.8% to 12.2%, which is consistent with the Company's request in this case.

(Exh. T-520, p. 12, *ll*. 1-14).

The following table summarizes the return on equity recommendations of each witness in relation to the ROEs for each member of their selected proxy groups:

Return on Equity Comparisons

		Lurito Allowed	*Lurito Earned*	*Hill Earned*	*Company Proposal*
ROE	14.5			X	
	14.0				
	13.5			X	
	13.0				
	12.5			X	
	12.0	X	X X		**O**
	11.5	X X X	X	XX	
	11.0		X	**O**	
	10.5	X **O**	**O**	X	
	10.0		X	X	

X = ROE's of comparable companies
O = Recommended ROE's

Sources: Lurito: Exhibit 634, Schedule 5.
Hill: Exhibit 623, Schedule 10.

Finally, if one looks from the perspective of the broader industry, so far during the year 2000, most allowed returns on equity have been in the range of 11.2% to 11.5%, as reported in the April 5, 2000, report from Regulatory Research Associates, Inc. Significantly, the average common equity ratio allowed in these decisions was 49.7%, which is significantly higher than the common equity ratios recommended by Dr. Lurito and Mr. Hill or even that proposed by the Company. (Exh. T-520, p. 12, l. 18 - p. 13, l. 3). If one were to adopt an equity ratio at lower levels, one would need to presumably adjust upward the allowed return on equity even above the 11.2% to 11.5% observed in this study. (Id.)

VII. KETTLE FALLS EQUITY INCENTIVE

The Company's investment in the Kettle Falls Generating Station qualifies for the "equity adder" provided for in RCW 80.28.025.[52] RCW 80.28.025 allows for a higher return on investment for renewable resources, conservation, and co-generation "by adding an increment of two percent (2%) to the rate of return on common equity permitted on the Company's investment." Kettle Falls meets all of the required criteria. In fact, as explained by Mr. Dukich, the Washington State Department of Revenue in February of 1991 ruled that Kettle Falls qualified for the renewable energy state tax credits under the provisions of RCW 82.16.055, retroactive to the plant's in-service date in 1983. It is important to note that RCW 82.16.055 and RCW 80.28.025 are "essentially identical with regard to qualifying criteria, were passed at the same time, and were viewed as working conjointly to provide financial incentives to encourage renewable energy and conservation," as explained by Mr. Dukich. (Exh. T-84, p. 9, *ll*. 18-22). Moreover, the provisions of RCW 80.28.025 state that the Commission "shall adopt policies" to encourage meeting demands through use of renewable resources, which "policies shall include. . . allowing a return on investment. . . of

[52] The Kettle Falls Generating Station is a wood waste steam plant near Kettle Falls, Washington. While originally designed to operate at 42 megawatts of capacity, the plant now operates at up to 50 megawatts or 19% over what was contemplated when the plant was partially put into rate base in 1983. (Exh. T-84, p. 8, *ll*. 19, p. 9, *ll*. 10). In addition, the availability factor for the plant over the past five (5) years has averaged 91% — well above the 75% availability factor used in the original economic analysis related to the planning of the plant. (Id.). Moreover, while the estimated first year fuel costs was $14.64 per ton at the time the plant was placed into rate base, the present level of fuel cost for Kettle Falls included in this filing is only $7.51 per ton (49% less than what the cost was projected some 15 years ago). (Id.).

two percent to the rate of return on common equity. . . ." Accordingly, the statutory provisions direct the Commission to implement the State policy, as expressed in the accompanying legislative finding in RCW 80.28.024 which provides, in pertinent part, that "actions and incentives by state government to promote conservation and the use of renewal resources would be of great benefit to the citizens of this state by encouraging efficient energy use and a reliable supply of energy based upon renewable energy resources."[53]

Staff, through the testimony of Mr. Parvinen, at pages 16-18 of his direct testimony (Exh. T-608) suggest that the Commission somehow "indirectly determined that Kettle Falls did not meet all the requirements in RCW 80.28.025 by not allowing the total investment in rate base." (Id. at p. 17, *ll*. 1-3). Mr. Parvinen argues that at the time Kettle Falls was placed in rate base, it was "not the lowest cost alternative and, therefore, does not meet the requirements set forth in RCW 80.28.025." (Id. at p. 17, *ll*. 23-25). When one, in fact, looks to the terms of this Commission's Order in Case No. U-83-26 (Fifth Supplemental Order dated January 19, 1984) one draws a different conclusion. As explained by Mr. Dukich, on rebuttal, the Commission stated on page 13 of its Order that "even accepting the alleged errors in the original cost study and making adjustments for them, the Kettle Falls project was still the lowest cost means of meeting the forecast need." The Commission went on to state that it was "of the opinion that the decision to initiate the Kettle Falls project, even considering the alleged flaw in the cost study, was prudent." (Id.) Again, at page 15 of its Order, supra, the Commission observed that "the expenses of the project as originally estimated appeared to be in and of themselves reasonable." And finally, the Commission concluded:

> The Commission is of the opinion that ratepayors should pay only for the cost of the project as originally estimated. This cost is the basis for the initial decision found to be prudent by the Commission. The remaining cost shall be borne by the Company. The effect of this

[53] The equity incentive for Kettle Falls, as proposed by the Company, will serve to increase the Company's net operating income by $252,000 and the associated revenue requirement by $406,000. (Exh. T-84, p. 10, *ll*. 3-5).

> decision is that $80,555,706 of the total project cost of $89,299,000 will be used to calculate the allocation between the jurisdictions.

(Emphasis applied). Accordingly, the net effect was that the Commission allowed into rates only the level that was considered to be the least cost alternative, which represented 90% of the total cost of the project ($80,555,706 out of $89,299,000). This $80,555,706 was derived from the original cost study referred to above at page 13 of the Commission's Order and that expenditure was deemed to be "prudent" and the "lowest cost means of meeting the forecasted need."

The important point is this: the Company is only seeking the two percent equity adder with reference to that portion of the Kettle Falls project ($80,555,706) deemed by this Commission to be the "least cost alternative," and does not propose to apply the adder to the larger figure representing the Company's total investment in the project. The lower figure representing ninety percent of the total project investment <u>was</u> allowed in rate base at the level this Commission deemed prudent and was equivalent to the least cost alternative according to the Commission's own reasoning.

In the final analysis, the requirements of RCW 80.28.025, the findings of this Commission in its prior Order in Cause No. U-83-26, and the companion determination by the Department of Revenue under identical statutory language, all support the inclusion of the equity adder in this proceeding.

VIII. COMPENSATION ISSUES

Company and Staff differ on a number of compensation issues, including executive officer compensation, allocation of executive compensation to regulated and non-regulated operations, team incentives and relocation expenses. This brief discusses each in turn, as well as the flaws in Public Counsel's administrative and general salary analysis.

A. <u>Executive Officer Compensation</u>

The Company proposes a proforma adjustment removing expenses of $417,021 and $105,703 from its Washington electric and gas operations, respectively. Staff, through Witness Huang, removes a greater expense level of $884,000 and $222,000 from Washington electric and gas operations, respectively. In the process, Staff excludes restricted stock compensation, signing bonuses and part of the CEO's base compensation, and otherwise reduces the base compensation for the other executives as a class as well. After effecting a 43% reduction in overall executive compensation, Staff then further reduces this officer compensation by allocating across the board 48% of the remainder to subsidiaries. (See Exh. T-393, p. 2, *ll*. 11-19).

At the outset, it should be remembered that total compensation for all eleven officers of the Company, as allocated to Washington electric and gas, represents only $1.2 million (electric) and $300,000 (gas), respectively. These amounts include base compensation, signing bonuses (amortized over five years), restricted stock awards and incentive pay. Table 1, excerpted from Company Witness Mitchell's rebuttal testimony (page 2 of Exh. T-393) sets forth this information in tabular form:

TABLE 1

All Officer Comp	System	**WA Electric**	**WA Gas**	Subsidiaries
Base Comp	$2,531,000	$883,000	$221,000	$674,000
Signing	250,000	75,000	19,000	92,000
Incentives	473,000	119,000	30,000	220,000
Restricted Stock	511,000	150,000	38,000	194,000
Stock Options	-- No Expense to Company or Utility --			
Total	$3,765,000	**$1,228,000**	**$307,000**	$1,179,000

The arithmetic average for all officers therefore approximates $112,000 per officer, as allocated to the electric Washington jurisdiction, for the total compensation package. (Tr., p. 1418, *ll*. 13-19.)

With regard to CEO base compensation, Staff Witness Huang reduces compensation from $750,000 to $570,000, even though Mr. Matthews' salary (base compensation) is within the range of reasonableness considering the total results of the Towers and Perrin compensation study. (Exh. T-393, p. 2, *ll*. 21-23). This study revealed that Mr. Matthews' base compensation is just under the 50th percentile for the $3 to $6 billion group (expressed as overall revenues) and between the 75th and 100th percentile for the $1 to $3 billion group, even before his salary is allocated to subsidiaries.

(Id., p. 3, *ll*. 12-14).[54] Company Witness Mitchell reminds us that the Company was "competing for executive talent not just from the smaller company pool ($1 to $3 billion), but also from the larger universe of companies ($3 to $6 billion)." (Id. at p. 2, *l*. 24 - p. 3, L. l). The more important point is this:

> The Company's Board of Directors should be given some measure of discretion in terms of what salaries are necessary to attract the sort of CEO candidate who will lead a company that is clearly repositioning itself — especially as that discretion results in base compensation within the range of reasonableness as shown by studies such as that prepared by Towers and Perrin.

(Id. p. 3, *ll*. 8-12).

Staff also took issue with other elements of executive compensation and removed signing bonuses and restricted stock awards as "not reflective of ongoing normal business expense." (See Exh. T-570, p.7, LL.3-4). Staff's logic is flawed, inasmuch as these elements of compensation are necessary recruitment tools, as Company Witnesses Mitchell and Feltes remind us. (See Exh. T-393, p. 3, *ll*. 18-23). In fact, in Staff's own data set (Exhibit 572), 30 out of the 41 companies use stock awards as a compensation tool and 8 out of the same 41 companies noted signing bonuses and/or relocation allowances as part of the compensation package for their executive officers in their Proxy Statements. (Exh. T-393, at p. 4, *ll*. 1-3). Furthermore, Witness Huang acknowledges that 19 of the 29 companies (listed in Appendix 1 of Exhibit C-576) that were part of the Towers and Perrin study used stock awards in their compensation programs (this was for the subset of companies in the one to three billion dollar revenue range). (Tr., p. 1428, l. 25 - p. 1429, l. 2.)[55]

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[54] After allocation of Mr. Matthews' salary to the Company's subsidiaries and its other utility jurisdictions, the Washington electric and gas jurisdictional allocations of his salary are only $212,000 and $53,000 respectively. (Exh. T-393, p. 3, *ll*. 5-7).

[55] During examination by Chairwoman Showalter , it became apparently that Ms. Huang was basing her recommendations on limited, and perhaps stale, precedent with respect to signing bonuses and stock options — for example a 1995 Oklahoma Commission decision. (Tr., p. 1470, *ll*. 15-24.)

Taken as a whole, the Towers and Perrin study (see Exhibit C-576, at p. 4) indicates that "in general: Base pay for Avista officers falls at or somewhat above the median competitive market levels for $1 to $3 billion peer companies." This is still well within the range of reasonableness, especially given the fact that this same study also observes that in other areas, such as expected value of stock option grants, Avista's compensation for officers actually lags behind the peer group. (Exhibit T-393, at p. 4, *ll*. 6-10).

Moreover, if we were to look just at the base compensation for the remaining 10 officers, totaling $1,781,000 (before allocations to subsidiaries and other jurisdictions), one would note that this is slightly less than the aggregate amount of $1,785,000 for the 50th percentile of the $1 to $3 billion peer group as shown in the same Towers and Perrin study. As observed by Company Witness Mitchell: In fact, if Witness Huang were to apply her own recommendation of pegging the CEO's base compensation at the 50th percentile of the $1 to $3 billion peer group to the remaining 10 officers, there would be essentially no difference between Staff's proposal and the Company's proforma base compensation for those officers. (See Tr. p. 1431, *ll*. 6-24).

B. Allocations to Non-regulated Operations

Staff would allocate 52% of executive compensation to regulated operations and 48% to non-regulated operations. It does this in an across-the-board fashion, relying on a formula that has a distorted application in the case of Avista. In the process, Staff ignores allocations based on the Executive's own informed judgment. For its part, the Company, on the basis of this judgment, allocated 31% of all officer compensation to subsidiaries. (Exhibit T-393 p. 5, *ll*. 6-9).

The Company allocated executive officer compensation on an officer-by-officer basis, given the informed judgment of each officer as to where that officer spends his or her time. Witness Huang's proposal, however, would have the effect of allocating officer compensation as "a pool" that does not differentiate among officers. (Tr., p. 1435, *ll*. 5-6.) Nevertheless, she acknowledges that within this officer pool, officers have differing responsibilities as between regulated and unregulated activities. (Tr., p. 1436, *ll*. 4-8.) Staff, however, in an across-the-board fashion, would allocate the entire pool 52% to the utility and 48% to subsidiaries. (Tr., p. 1436, *ll*. 9-13.)

Officers have responsibilities that differ greatly with respect to regulated and non-regulated operations. While Mr. Turner (Vice President and general manager of Energy Delivery) has allocated all of his time to regulated operations, others such as Mr. Matthews and Mr. Ely have allocated only 50% - 60% of their time to utility operations. (Exh. T-393, at p. 5, *ll*. 15-20). And yet, Staff's across-the-board allocation factor would allocate, in the case of Mr. Turner, 48% of his time to subsidiary operations producing a "counter intuitive result." (Id. at p. 6, *ll*. 1-2). As testified to by Company Witness Mitchell:

> Any formula that produces results spread across the entire officer group will not recognize substantial differences among officers and their differing responsibilities. It will not allow for use of informed judgment by each officer concerning prospective changes in work responsibilities (regulated versus non-regulated) as their responsibilities evolve over time.

(Id. at p. 6, *ll*. 3-7).

Even if a formulaic approach were to be applied, Staff has proposed a formula that produces distorted results. Its formula is based on a 3-year average of operating revenues, number of employees and non-officer wages, similar to an allocation methodology that was previously used for Washington Natural Gas in Docket No. UG-920840. In the process Staff used subsidiary operating revenues as one of the primary inputs, without recognizing that energy trading companies, like security trading companies, have unusually high volumes of revenues matched by unusually high volues of expenses when compared to other types of businesses. Most of Avista Energy's operating revenue transactions ultimately result in purely financial transactions, situations where energy simply does not flow. (Id. at p. 6, *ll*. 16-17).[56]

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[56] The Washington Department of Revenue, in its review of Avista Energy's operating revenues, has concluded, that if the transaction is a purely "financial transaction" and no energy flows, then only the net trading gain or gross margin will be the basis for the application of the B&O tax. The Department of Revenue indicates that the proposed tax treatment will closely parallel the

As the majority of subsidiary operating revenues are from Avista Energy, the use of unadjusted Avista Energy operating revenues seriously skews the outcome of Staff's proposed formula. (For example the 1998 subsidiary revenues used by Staff as an input were $2,642,268,000, per Exhibit 574 at p. 2, while 1998 Avista Energy revenues were $2,408,734,000, per Exhibit 5, at p. 16. Avista Energy's 1998 revenues, therefore, make up 91% of the 1998 subsidiary revenues Staff uses as a formula input.)

This formula, derived for Washington Natural Gas has no meaningful application in the context of Avista. There, the allocations related to merchandising and jobbing of non-utility products, a gas and oil exploration and development business and a home security business — none of which maintained the abnormally high level of revenues of an energy trading operation. Moreover, Washington Natural had charged a relatively small amount of executive compensation to its subsidiary operations — unlike Avista which has charged $1,179,000 to its subsidiary operations. (Id. at p. 7, *ll*. 5-1). Washington Natural only charged approximately $137,000 of executive compensation to its subsidiary operations; by way of comparison, in this proceeding, the Company is proposing to allocate approximately 38% to subsidiary operations. (Tr., p. 1440, *ll*. 5-11.)

There is yet another flaw in the Staff's proposal, inasmuch as it uses the number of subsidiary employees, including employees of third and fourth tier subsidiaries who are not direct employees of Avista. By including a substantial number of employees from these third and fourth tier subsidiaries, this distorts the results. Witness Huang used 2,153 employees as the head count for purposes of her formula. (Tr., p. 1441, *ll*. 5-14). Exhibit 582 shows that for the test year 1998, the Company had 1,342 employees engaged in utility operations and only 140 engaged in subsidiary operations. (Tr., p. 1443, *ll*. 7-16.) The figure of 140 is, of course, much smaller than the figure of

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treatment afforded "Stockbrokers & Security Houses" reflected in WAC 458-20-162. Staff should clearly follow the Department of Revenue's logic and adjust Avista Energy's operating revenues accordingly for purposes of its analysis. (Exh. T-393, p. 6, *l*. 18- p. 7, 1.2).

2,153 subsidiary employees assumed by Witness Huang for purposes of her allocation formula. This is because her figure includes 2,013 employees that worked within the many operating subsidiaries underneath Pentzer during the test period - none of which are under the direct control or supervision of Avista officers.

If one were to correct the revenue and employee count factors, Company Witness Mitchell testifies that it would result in an overall subsidiary allocation factor of only 15.22%, which is substantially less than the 31% charged by the officers on the basis of their "informed judgment." (Id., Exh. T-393, at p. 7, *ll*. 20-23). (See also Exhibit 394). Finally, by way of summary, if one were to (a) correct all flaws in the allocation study; (b) set all target compensation at the 50th percentile for the entire officer group; and (c) include the five year amortized levels of signing bonuses and restricted stock compensation, one would arrive at proforma allocations of $1,245,000 for electric operations and $313,000 for gas operations. This is almost identical to what the Company is proposing ($1,228,000 to electric and $307,000 for Washington gas). (See Exh. T-393, p. 8, l. 15 - p. 9, l. 7).

C. Team Incentives

Staff Witness Huang simply removes the entirety ($4.4 million) of team incentives. Staff's objections surrounding the Company's Team Incentives center around two themes. The first objection is that "the plans are not customer-service oriented and do not benefit regulated customers" (See Exh. T-570, at p. 14) and instead are tied to earnings per share and shareholder benefit (Tr., p. 1454, *ll*. 4-13.) The second objection is that if incentives are incorporated into rates and if the Company does not pay those incentives in a given year then ratepayers are disadvantaged. (Tr., p. 1474, *ll*. 16-24).

To begin with these team incentives were widely disbursed throughout the organization. A total of $2,116,000 went to the energy delivery and transmission team, $1,164,000 was earmarked for the energy/market services/generation subset of employees; $647,000 was received by administrative employees; and $473,000 was received by officers ($220,000 of that was charged out to subsidiary operations). Additionally, union employees included in the above groups received $1,371,000. (Exh. T-393, p. 9, *ll*. 15-19).

Company Witness Mitchell, in her rebuttal, provided several examples of how the goals that drove incentive payments were targeted toward providing benefits to customers. For example, the incentive plan for the energy delivery and transmission team included an explicit customer satisfaction target whereby employees would be eligible if satisfaction ratings exceeded a 60% excellent rating in a survey.[57] (Exh. T-393, p. 10, *ll*. 1-10). This one allocator alone (i.e., customer satisfaction) accounted for approximately $900,000 of the $2.1 million paid out to the Energy Delivery Group. (Tr., p. 1450, *ll*. 5-12.) Moreover, the incentive plan for energy and market services included goals such as the "incremental improvement of megawatt availability for hydroplants above a baseline of 95%." (Exh. T-393, p. 10, LL. 12-15) By way of a final example, the administrative group received incentives based on efficiency teamwork goals such as working with and encouraging operational personnel to process plant retirements in a timely manner. This goal emphasizes to employees the importance of reliable accounting records which are ultimately used for rate making and depreciation studies. (Id. p. 11, LL. 17-22) Examples aside, the broader and ultimately more important point is simply this:

> . . . The Company is looking for additional ways to provide motivation for all employees to excel. A motivated workforce will, in the broader sense, provide additional benefits to customers.

(Exh. T-393, p. 11, *ll*. 1-4). It is true that $4.4 million in team incentives is in excess of incentive awards for prior years. Company Witness Mitchell testified that the average level of team incentives paid during the five year period (1995-1999) was $1.8 million; this, again, should be compared with staff's effort to proform in zero for team incentives. (Tr., p. 2199, *ll*. 7-17). Nevertheless, the Company, given dynamic changes in the competitive utility industry, has had to rethink its

[57] Whole some goals in the 1998 incentive were designed around achievement of specific levels of net operating income or cost controls, these objectives, as well as others detailed in the 94 pages of Exhibit 401, were not.

compensation strategy both in terms of base compensation and incentive compensation. The 1998 team incentive plan provided a framework for greater incentive opportunity as well as line of business accountability. (Id. at p. 11, *ll*. 11-17). The use of incentives are, in the final analysis, a necessary recruitment and retention tool, as further explained by Company Witness Feltes in her rebuttal testimony.[58]

D. Relocation Adjustment

Staff simply averages two noncontiguous years (1997 and 1999) that have the lowest relocation costs and throws out the intervening year — 1998 — as nonrepresentative. In the process Staff also excludes any officer relocation expenses. It is wrong to assume, as does Staff, that relocation costs should remain at some constant baseline level from year-to-year. More problematic, however, is Staff's arbitrary exclusion of all 1998 test period relocation expenses as part of the averaging process. (Exh. T-393, p. 12, l. 20 - p. 13, l. 2).

E. Public Counsel's A & G Salary Analysis is Faulty

Finally, Public Counsel Witness Lazar performs a faulty analysis which compares 1998 administrative and general salary levels to 1984 levels. He argues that, after adjusting for inflation and customer growth, that the difference between the two years be disallowed. Had Mr. Lazar accurately performed this comparison of 1984 and 1998 amounts, one would observe that the Company's administrative and general salaries actually increased at approximately the same level of inflation and customer growth as proposed by Mr. Lazar. Exhibit 396 makes the necessary corrections. The 1998 number contained in Mr. Lazar's analysis contained payroll loading for payroll taxes, benefits and paid time-off, while the 1984 number does not. Additionally, the 1998

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[58] Likewise, with respect to team incentives, Witness Huang steadfastly adheres to what she understands to be a policy enunciated in a 1992 rate case (Docket No. 920433) without recognizing the possibility that there are changed circumstances in the utility world, which may require differing compensation strategies for recruitment and retention. (Tr., p. 1471, l. 4 - p. 1472, l. 2.). Docket UG-920840, from which witness Huang derives her proposed allocation formula, indicates that incentive goals such as controlling costs, promoting energy efficiency, providing good customer service, and promoting safety advantage ratepayers as well as shareholders.

number contains $1,695,000 of team incentive awards which the Staff addresses separately. Accordingly, these two items must be subtracted when developing a comparison over time of A&G salaries.

Even if one were to accept the premise (which the Company does not) that growth in A&G salaries should be limited to inflation and customer growth, as shown in Exhibit 396, the increase in the Company's A&G salaries actually approximates Mr. Lazar's proposed A&G salary level: 1998 adjusted A&G salaries are $5,725,000 — only 2.8% higher than Mr. Lazar's proposed level of $5,568,000. (Exh. T-393, p. 14, *ll*. 1-4). Mr. Lazar's contention that salary increases should not exceed the growth in CPI is wide of the mark. Interestingly enough, the American Compensation Association Report on 1999-2000 total salary increase project survey states that "salary increases have surpassed inflation rates by a significant amount: salary increases for 1999 in the United States were, on average 4.4%, as compared with inflation rate of 1.7%." Even the Washington State minimum wage has outstripped inflation between 1984 and 1998. (Exh. T-535, at p. 6, *ll*. 2-7).

F. Conclusion --- Overall Compensation Philosophy

Witness Feltes, on rebuttal, generally summarized the changing compensation philosophies employed by the industry at large, and Avista, in particular, when seeking to attract and retain key talent. Ms. Feltes has had a career in human resources for over 20 years, which included various senior level human relation management positions in both public and private industry, including King County and Microsoft. (Exh. T-535, p. 1, *ll*. 7-15).[59] On behalf of the Company, she makes several key points: (1) executive compensation strategies have evolved significantly in recent years with greater emphasis on bonus and incentives as recruitment and retention tools; and (2) the

[59] Ms. Feltes has also received formal training by the American Compensation Association in the areas of executive compensation and she is currently a member of this association as well as a member of the Society for Human Resource Management. (Id.) In contrast, Staff Witness Huang has no degree in human relations or organization matters, has taken no extensive coursework in these areas, nor has she received any training on executive compensation strategies. (Tr., p. 1413, *ll*. 16 - p. 1414, l. 8.)

Company management and its elected board members should be given some "discretion in matters related to executive compensation and broad based incentive plans, as they chart the future strategic direction of the Company in a rapidly changing environment." (Id. at p. 6, *ll*. 10-16).

In the process, ratepayers derive benefit from the Company's strategy, inasmuch as effective and capable utility management can drive innovation, efficiency and leadership of strategic initiatives. (Id. at p. 2, *ll*. 18-22). In the process, though, it should be remembered that the Company is competing in a "national hiring market" — one that is much broader than just the State of Washington, as explained by Witness Feltes. (Id.)[60]

Finally, Ms. Feltes offers a word about team incentives. The 1998 team incentive plan mirrors the Company's compensation philosophy which includes "pay for performance." This incentive compensation is a "valuable tool to increase employee's focus on immediate goals that support overall quality customer service and operational efficiencies," as explained by Witness Feltes. (Id. at p. 5, *ll*. 7-20). While this incentive plan may vary from year-to-year, the overall message is simple: "Employees can have an impact on the success of the Company." (Id.)

IX. OTHER PROFORMA ADJUSTMENTS

A. Injuries and Damages Adjustment

The Commission Staff, through Mr. Schooley, contends that the litigation costs associated with obtaining a settlement of the 1991 Firestorm litigation, and the entirety of the 1996 Ice Storm costs, should not be recoverable.

1. Firestorm Litigation Costs

Turning first to the Firestorm cost recovery, while Staff accepts the final settlement of the six-year litigation, net of insurance proceeds, as recoverable in the Injuries and Damages adjustment,

[60] Public Counsel's comparison of Avista's executive leadership compensation with a PUD's general manager compensation is not valid. As explained by Company Witness Feltes a publicly-traded company requires more complex interactions with the financial markets in which it operates. Additionally, the diversification in investor-owned utilities is considerably greater, and presents differing challenges, than those faced within a PUD organization. (See Exh. T-535, p. 4, *ll*. 6-21).

staff excludes the costs associated with obtaining that settlement, arguing that recovery of specific legal fees is "unnecessary and duplicative" of the ongoing legal expense already recovered in rates. (See Exh. T-595, at p. 4). This, of course, ignores the unique and highly complex nature of the Firestorm litigation which spanned a period of six years and carried with it the potential for significant damages. Staff, through Witness Schooley, would accept the settlement payments themselves as reasonable for recovery, but not the associated litigation costs that were incurred in order to reach that settlement. (Tr., p. 1493, *ll*. 14-20.) Mr. Schooley acknowledged that he was offering no testimony or opinion as to whether or not the Firestorm litigation costs were necessary to achieve the settlement. (Tr., p. 1493, *ll*. 9-13.)

As testified to by Company Witness Falkner, "the legal and other settlement costs, such as claims investigation, surveys and outside consultants, are inextricably tied to the final settlement"; stated differently, they do not represent anything "close to normal levels of year to year legal expenditures." (Exh. T-268, p. 7, *ll*. 12-15). Normal levels of year to year legal expenditures for Injuries and Damages are otherwise reflected in rates. Extraordinary legal costs associated with extraordinary litigation, such as Firestorm, are in addition to these costs. Accordingly, the Company is seeking to recover Firestorm litigation costs, as well as the Firestorm settlement amount, but is doing so through the Injuries and Damages adjustment which essentially amortizes such costs over a six-year period.

2. Icestorm Costs

As concerns the recovery of Ice Storm costs, Mr. Dukich's rebuttal testimony, on behalf of the Company addresses this issue squarely. (Exh. T-84) At the outset, it should be noted that no witness has questioned the legitimacy or prudence of the $12 million of costs incurred to restore service after the Ice Storm of 1996. (Id. at p. 12, *ll*. 6-10). If one accepts the basic premise that the Company has a "public service obligation" to restore service as quickly and as safely as possible, then these costs were, by definition, legitimate business expenses that were necessary to fulfill that public service obligation, as testified to by Mr. Dukich. (Id.)

Staff seems to contend that the Company did not ever intend to collect these costs in a rate proceeding, citing references to the 1996 Form 10-K and a company press release. While the Company did not seek to recover Ice Storm costs through general rate relief shortly after they were incurred in 1996, the Company never suggested that it would not seek subsequent cost recovery. Indeed, as testified to by Mr. Dukich, the Company's proposal for ultimate cost recovery was "memorialized" and is clearly outlined in the Company's "Ice Storm '96 Overview Report" that was signed by Mr. Redmond and submitted to this Commission just two months after service was restored. (See Exh. 85) In that Exhibit, the Commission was advised that the Company might, at some later date, seek cost recovery:

> The remaining $17.1 million ($11.1 million after tax) will be included with other non-insured losses from storms and accidents. The annual expense level is determined through use of a six-year average. WWP will not seek a specific rate surcharge due to the costs of Ice Storm '96 restoration.

(See Exh. 85, p. 14 (Section 3.7)).

Moreover, the press release that was issued by the Company merely indicated that the Company had no intention of seeking cost recovery at that time (1996) by means of a rate surcharge. At the time, the Company was responding to questions concerning whether there would be an immediate impact on rates, and the Company indicated there would not be. When all is said and done, this Commission should recognize that those costs were prudently incurred in order for the Company to discharge its public service obligation and restore power as quickly and as safely as possible. As a final note, as Mr. Dukich observed in his rebuttal, cost recovery is especially appropriate in the current case since it can now be accomplished without burdening the revenue requirements: The gain from the Centralia sale can be used to totally offset these costs, as recommended by Mr. Dukich. (Id. at p. 14, *ll*. 4-6).

Also, it should be recalled that the Company, beginning with the Semi-Annual Reports filed for the twelve-month period ending December 31, 1996, included Ice Storm costs as part of its six-year average for Injuries and Damages, as testified to by Mr. Falkner. (Exh. T-268, p. 8, *ll*. 16-19). Staff has never questioned that component of its adjustments for semi-annual reporting purposes. (Tr., p. 1497, 1. 25-p. 1498, l. 15)

Finally, Staff Witness Schooley argues that because the storm damages were to Company-owned property — not to property owned by third parties — such damages could not be recovered through the Injuries and Damages adjustment insofar as it purports to address only damages to third parties. (Exh. T-595, at pp. 5-6). On cross-examination, Mr. Schooley was asked if this was a meaningful distinction for purposes of this adjustment:

> Q: Now let's explore whether this is a meaningless or a meaningful distinction between damage to third parties or damage to Company-owned property. Would you agree conceptually that whether or not the damage was to the property of the Company or to a third party, the necessity for expenditures may be the same in order to fulfill a public service obligation?
>
> A: Necessity to cure the damage is there.
>
> Q: In either circumstance?
>
> A: Yes.

(Tr., p. 1499, *ll*. 7-16.) Stated differently, these Ice Storm damages were extraordinary, uninsured property losses that, in the final analysis, are not unlike the Firestorm situation: to allow recovery of Firestorm losses while disallowing Ice Storm damages would seem unreasonable.

Mr. Schooley testified, on cross-examination, that Staff has not questioned the legitimacy or prudence of the $12 million of costs incurred by the Company to restore service after the 1996 Ice Storm; moreover, he agreed the Company has a "public service obligation" to restore service quickly, efficiently and safely and that the Ice Storm costs were, by definition, legitimate business expenses that were necessary to meet its public service obligation:

> Q: Now, let's turn to the subject of ice storm costs. Have you or has any other witness from the Staff questioned the legitimacy or the prudence of the $12 million of costs incurred by the Company to restore service after the ice storm of 1996?

A: No.

Q: Does the Company, Mr. Schooley, have a public service obligation to restore service as quickly, efficiently, and safely as possible?

A: Yes.

(Tr., p. 1495, *ll*. 11 - 20)

Exhibit No. 602 contains an excerpt from this Commission's Eleventh Supplement Order, dated September 21, 1993, in the Puget Sound Energy case (UE-921262), in which the Commission addressed the recovery of storm damage costs. At page 51 of that Order (page 2 of Exhibit 602), it reads as follows:

> Mr. Schooley proposed normalizing the storm damage expense based on a 6-year period and that truly extraordinary events should be deferred as extraordinary property damage and amortized into rates over a 6-year period.

(Tr., p. 1501, l. 18 - p. 1502, l. 9.) The Commission, in that proceeding, went on to accept Mr. Schooley's recommendation to use a 6-year average for the purposes of normalizing the storm damage. Moreover, Witness Schooley acknowledged that the storm damage suffered by Puget related to Company-owned property, as opposed to third parties:

Q: Were these storm damages suffered by Puget damages to Company-owned property by and large, or were they damages to third parties?

A: To Company-owned property, and that was the sole subject of that particular portion of this discussion.

(Tr., p. 1502, *ll*. 15-20.)

Moreover, in this same Eleventh Supplemental Order, this Commission determined that storm damages should be normalized and should be amortized in rates over a 6-year period, <u>notwithstanding the lack of a deferred accounting order</u>. In that proceeding involving Puget, the Company had not previously requested a deferred accounting order with regard to its storm damages. (Tr., p. 1541, l. 6 - p. 1542, l. 14.) (<u>See</u> <u>also</u> Exhibit 602.) Chairwoman Showalter explored with Staff Witness Schooley whether an accounting order was an absolute pre-requisite to later recovery of the ice storm costs:

Q: Yes, but don't we have that same opportunity today. I'm not saying it's ideal, because we all would have been more familiar with this issue in '96 or '97, but isn't that the exercise we're going through today instead of having done it in '97? Is this or isn't this an extraordinary expense that should be amortized over 5 years?

A: You have that choice before you, yes, that's true.

Q: And also, when we do the accounting petitions, as I recall, when they are done timely, which seems to be a better method, do we approve them or don't we have some language in there that we're not actually finally approving the prudency of them if that's the right word, until the next rate case?

A: Yes, that's true.

Q: So whether or not it was filed "when it should have been" or today, isn't the ultimate decision on it, doesn't it wait until the rate case anyway?

A: For the prudence of the expense itself, usually in the accounting petitions you're only giving the Company permission to take what would be an expense for the year and allowing them to put it on their balance sheet instead so that it doesn't look so bad on their financial statements.

(Tr., p. 1546, l. 9.)

B. <u>Pro Forma Miscellaneous Adjustments</u>

Staff, through witness Schooley, eliminates two items contained within this adjustment: the amortization of <u>corporate name change costs</u> and <u>Y2K computer costs</u>, contending that both categories are non-recurring. Staff otherwise provides no substantive arguments that the costs were imprudent or otherwise unnecessary. For its part, Public Counsel also argues that the Company's requested recovery of "name change" costs be disallowed.

1. Y2K Cost Recovery

The Company proposed to amortize its Y2K costs incurred during the 1998 test period over a five-year period, in order to better reflect the long-term nature of these costs. (In the process, the

Company is not seeking recovery of all Y2K expenditures; for example, Y2K expenditures incurred in 1997 and 1999 were excluded from the request.) (See Exh. T-268, p. 13, *ll*. 15-19).

Staff witness Schooley, however, recommended that all Y2K operating expenses be completely eliminated, arguing that they were "non-recurring." (Exh. T-595, p. 15, l. 11). He otherwise dismisses the adjustment by noting that "it is the Company's responsibility to maintain all of its systems in proper functioning order regardless of the calendar numerals." (Id. at p. 15, l. 14).

At the outset, the Commission should appreciate the scope of the Company's Y2K effort. Avista addressed not only computer hardware and software issues, but, in the process, addressed other peripheral matters as well. As explained by Mr. Falkner, in addition to looking at desktop computer systems, business systems, and embedded systems, Avista also took the opportunity to address such important issues as: our energy supplier's ability to deliver, our emergency services preparedness, our internal/external communication systems' reliability, security at our physical facilities, and the emergency power distribution capabilities within our facilities. (Id. at p. 12, l. 17-p. 13, l. 2). These have ongoing benefits for our customers. This initiative was important to be fully prepared for the Y2K contingencies. These are, in the final analysis, legitimate and necessary business expenses that were prudently incurred in the carrying out our responsibilities. If the utility is properly charged with maintaining safe, adequate and reliable service, it would have been derelict in not responding to the Y2K risks.[61]

Mr. Schooley acknowledges that it is the Company's responsibility to maintain its systems in proper functioning order (see page 15, *ll*. 14-16 of Exh. T-595). Indeed, he acknowledges that that is part of its "public service obligation." (Tr., p. 1506, *ll*. 10-14.) Moreover, the benefits obtained through this process are ongoing, as opposed to non-recurring as argued by staff. Avista's Y2K

[61] Indeed, SEC reporting guidelines attested to the importance of these expenditures, requiring detailed disclosure to investors in the annual Form 10-K concerning how every publicly-traded company was planning on addressing the issues. (Exh. T-268, p. 13, *ll*. 9-12).

efforts were designed to ensure delivery of energy over the long run. In that respect, it is not different than other efforts which center on the delivery of safe and reliable service. In fact, Avista's Y2K preparedness was held up as a state-wide model for preparedness, as testified to by Mr. Matthews. (Exh. T-14).[62]

2. Name Change Costs

As was true with Y2K expenditures, the Company has proposed to normalize name change costs over a five-year period to better reflect the longer term benefits of these expenditures. (Again, the Company has only included test year name change expenditures — not other expenditures made in 1997 or 1999.) (Exh. T-268, p. 17, *ll*. 6-11).

Mr. Falkner recounts the brief history surrounding the name change. Before the name change, the Avista name was used in 1997 by the Company's subsidiaries under our internal holding company, then called Avista Corporation, Inc. Subsequently, in early 1999, the "Washington Water Power" name was retired and the Avista Corporation name was transferred from the internal holding company to the parent company (formerly the Washington Water Power Company). As a result, retiring the use of the "Washington Water Power" name helped reduce the level of confusion with investors, analysts, third-party contractors, and in national publications. (Id. at p. 15, l. 17). The name "Washington Water Power" no longer reflects the nature of the Company's utility business — which is no longer confined to the state of Washington and does not supply "water."[63] As further

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[62] Staff witness Schooley does not even acknowledge that "normalization" of these Y2K costs is a possibility, choosing, instead, to eliminate them altogether. Avista continues to believe that normalization is the appropriate treatment for such costs. (Exh. T-268, p. 15, *ll*. 4-12).

[63] As an aside, Public Counsel attorney Mr. ffitch, while cross-examining Mr. Matthews in regard to the name change candidly acknowledged:

> Q: I will confess, Mr. Matthews, that my spouse thought that I was doing a water company rate case this week. I wondered why, but . . .
>
> A: See.

testified to by Mr. Matthews, confusion with analysts and the investment community at large has been mitigated through the name change.

Public Counsel, for its part, raises an additional issue surrounding the name change, suggesting that the Company's non-regulated operations should contribute a "franchise fee" to the utility for use of the corporate name. Public Counsel's concept, if adopted, actually argues for the reverse: because the "Avista" name was originally developed and used by the Company's non-regulated operations, the regulated utility business should, arguably, pay a "franchise fee" to these non-regulated businesses. (Exh. T-268, p. 17, *ll*. 16-22).[64]

C. Pro Forma Nez Perce Adjustment

Staff witness Schooley at pages 12-13 of his direct testimony (Exh. T-595), proposes to reduce the Company's adjustment as a result of a "derived" assignment of settlement costs to the Idaho Electric distribution system.[65] Staff's attempt to "derive" or "impute" an assignment of costs for utility rights-of-way and tribal taxes flies in the face of the global nature of the settlement. Stated differently, this "global" or "black box" settlement did not purport to assign dollar values to individual issues relating to rights-of-way and tribal taxes. As explained by Company Witness Falkner, the right-of-way and tax issues were simply eliminated as part of a negotiating process that

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(See Tr., p. 129, *ll*. 14-17).

[64] Nor is this Commission's decision in Docket No. UG-931405 involving use of the corporate logo and association by non-regulated subsidiaries precedent setting. The Commission merely adopted a stipulation signed by representatives of Washington Natural Gas, Staff and intervenors which, by its terms, was not precedent setting. Moreover, in that settlement stipulation, the amount to be imputed was not to exceed $240,000; Mr. Lazar proposes, in this proceeding, an amount that is "approximately twelve times higher than the above-referenced $240,000. Clearly this is an unreasonable result." (See Falkner Rebuttal, Exh. T-268, p. 18, *ll*. 14-20).

[65] Under the settlement agreement, the Company provided a payment of $2,500,000 to the tribe in 1999, and annual payments of $835,498 for the next 44 years. The Company seeks recovery of the levelized payments (amounting to $872,487) on a system-wide basis. Staff assigned approximately three percent of the annual payment amount to Idaho operations for distribution line rights-of-way and a similar amount for an imputed level of tribal taxes. (Exh. T-595, p. 13, *ll*.5-15).

first and foremost related to damages allegedly caused by the prior operations of the Company's dams. (Exh. T-268, at p. 19, *ll*. 10-18). Accordingly, Staff's adjustment is arbitrary.

D. Miscellaneous Restating Adjustments

Staff witness Schooley suggests the removal of certain test year expenses such as political advertising, promotional advertising, and certain subsidiary expenses.

1. Political Advertising

Staff completely disallows corporate memberships in outside organizations. In fact, as explained by Mr. Falkner, these outside organizations conduct virtually no lobbying. The Company otherwise attempts to account for all true lobbying expense to non-utility accounts — i.e., below the line. (Exh. T-268, p. 20, *ll*. 4-13).

2. Promotional Advertising

The Company accepts Staff's recommendation with respect to a disallowance for promotional advertising.

3. Payment to Montana Power

The Company paid $125,000 to Montana Power Company as part of the process for considering the sale of the Colstrip generating plant. Ultimately, the Company withdrew from the sale process. Staff argues that this is non-recurring. The Company accepts this Staff adjustment.

4. Redmond Tribute Film

Staff disallows expenses associated with a film that was produced in order to honor Paul Redmond upon his retirement. The Company disagrees. This tribute film was important for employee morale, and is an appropriate type of expenditure for any Company that, in the ordinary course of business, would honor a long-time employee and CEO of the stature of Mr. Redmond, as explained in Mr. Falkner's rebuttal. (Id. at p. 20, *ll*. 16-22).

5. Website Design

The Company is willing to accept staff's proposed allocation of website design costs to non-regulated subsidiaries, after correcting the original calculation which incorrectly utilized the inverse of the utility allocator. (See Exh. T-268, at p. 21, *ll*. 1-5).

6. CEO Search Costs

Staff allocated 48% of the CEO search costs to subsidiaries. The total search costs reflected in the Company's rate proposal was in excess of $400,000. The Company disagrees with the concept of assigning as much as 47.7% of the search costs to non-regulated operations. Elsewhere, the Company has pointed out the flaws in the allocation by Staff of up to 47.7% of costs associated with compensation to non-regulated subsidiaries. In fact, as shown by Company Witness Mitchell, a more reasonable subsidiary allocation, overall, of compensation expenses for officers would be 15.22%. (See Exh. T-268, p. 21, *ll*. 6-14). The point is simply this, "with or without subsidiaries, the Company would have gone through the same rigorous, national search for a new CEO," as explained by Mr. Falkner. (Id.).

7. Toronto Dominion Costs

Staff incorrectly assumed a duplication of expense relating to Toronto Dominion fees associated with revolving lines of credit. As explained by the Company in rebuttal, the payments to Toronto Dominion are for maintenance of short-term debt lines of credit. These amounts are not otherwise factored into the short-term rates by the Company in this case and, as such, are general operating costs not captured in the cost of capital calculations. Simply put, there is no duplication as assumed by Staff. (Id. at p. 21, *ll*. 15-19).

E. Restatement of Excise/Franchise Fees

While the Company does not take issue with Staff's adjustment to restate Excise taxes from an accrual to the actual amounts recorded for the test period, Company and Staff do differ with respect to the inclusion of Franchise Fees as a general cost of operation and as a component of the Company's conversion factor — it should be noted, parenthetically, that the Company's proposed regulatory treatment for the recovery of these Franchise Fees from customers has been "in place for decades," as testified to by Mr. Falkner. (See Exh. T-268, p. 9, *ll*. 14-18).

Staff misreads the applicable provisions of RCW 35.21.860 to somehow preclude the Company from recovering Franchise Fees that are not shown to be directly related to "actual" administrative costs of the cities. A careful reading of RCW 35.21.860 reveals in Subsection (2), that any such limitation does not apply with respect to Franchise Fees imposed by contracts existing on April 20, 1982. Noteworthy is the fact that the electric and gas franchise ordinances here at issue, involving the cities of Spokane, Millwood, and Colville, were all in existence before April 20, 1982, and, accordingly, fall under the exception provided in Subsection (2) of RCW 35.21.860. Stated differently, there is no requirement that these Franchise Fees be somehow limited to the "actual" administrative expenses otherwise identified in Subsection (1) of this statute.

Perhaps more importantly, however, is the fact that Franchise Fee costs which are three percent (3%) or lower have been treated as a system-wide expense by this Commission for all utilities for purposes of results of operations. In this Commission's Order in Cause Nos. U-79-43, U-79-49, and U-79-50, dated May 13, 1980, this Commission addressed, in a generic docket applicable to all utilities, the very issue of whether Franchise Fees should be recovered from all rate payers or only the payers within the City imposing such a fee. (Order attached as Exhibit 271). In its Finding of Fact No. 18, this Commission concluded:

> Franchise Fees which municipalities in the state of Washington have historically imposed on revenues derived from sales made by public utility companies within their corporate limits average approximately 2.5%. Expenses attributable to any such Franchise Fees not exceeding 3% are reasonable expenses to include in general operating expenses; expenses attributable to Franchise Fees exceeding 3% of revenues from respective municipal sales should be passed on directly to customers in the municipalities collecting such fees.

There is, accordingly, no basis in this record for reversing a decade's-old generic determination by this Commission that the appropriate method for treating Franchise Fees for rate-making purposes is as discussed above.

F. Depreciation Adjustment

Company and Staff reached a negotiated agreement as to the depreciation parameters and rates to be used for depreciating Avista's plant and equipment. This is reflected in revised Exhibit No. 291. Mr. Damron, on behalf of Public Counsel, has also recognized this stipulated agreement between the Company and the Staff by including the effect of the recommended depreciation rates in his recommended revenue requirements. Public Counsel, however, proposes what Mr. Falkner characterizes as an "extreme departure from standard regulatory and financial accounting practice in regards to depreciation expense on hydroelectric power plants." (Exh. T-268, p. 29, *ll*. 7-11).

Mr. Lazar argues, with reference to hydroelectric production plant, that "there is no justification for accumulating depreciation at this time, as it will only exacerbate the excess depreciation accumulation about which the Commission expressed concern that a future commission would be unable to recapture for the benefit of ratepayers." (See Exh. T-691, p. 10, l. 27). His recommendation to essentially "defer" depreciation expense violates historical cost-based accounting and Generally Accepted Accounting Principles (GAAP). Essentially, Mr. Lazar is touting the difference between fair market value and net book value of hydroelectric plants as the main support for his proposal to defer depreciation expense. This would violate a fundamental aspect of GAAP, inasmuch as the Company would not be allowed to reflect any expense relating to assets that are being consumed. This prompted Mr. Falkner to observe:

> If market value is to be taken into consideration in regulatory decisions regarding rate recovery, as Mr. Lazar is suggesting, and one accepts the contention the net book value of electric utility assets understates their market value, shouldn't then utility rate base for the same assets be increased to reflect 'true' market value of the common equity investment made by the Company?

(Exh. T-268, p. 27, *ll*. 1-6).

Moreover, a consistent application of his argument would result in market-value rate base and market value (or replacement costs) based depreciation expense. Finally, his argument relating to market value of assets being higher than net book value of the same assets suggests that "the output of the plants is of more value than what the current price (rates) charged to ratepayers reflects, since the rates are based on net depreciated historical/original costs," as explained by Mr. Falkner. (Id. at p. 27, *ll*. 16-20). Nor does Mr. Lazar analyze the cash flow implications for the Company or its customers or how this might affect the Company's reinvestment in infrastructure.

Mr. Lazar's proposal, in the final analysis, will deprive the Company of its right to a return of its investment. This Commission should not engage in such a fundamental shift in regulatory philosophy without a comprehensive study justifying such a course.

G. Hydro Relicensing Costs

The Company requests recovery of ongoing annual expenses associated with meeting the conditions of the recently issued license with respect to the Clark Fork projects, plus the amortization of approximately $14 million in costs incurred to reach the Settlement Agreement.[66] For its part, Staff, through Mr. Schooley, originally proposed an expense level for Protection, Mitigation and Enhancement Measures (PME Measures) of $1,268,000 (system) or $650,000 (Washington). It otherwise accepted the Company's proposal to capitalize the costs associated with reaching an agreement and to amortize those over the 45-year life of the license. (See Exh. T-349, p. 10, *ll*. 11-17). It excluded what it termed incremental administration costs because it believed the Company had provided "inadequate details to quantify any known and measurable incremental costs." (Id. at p. 11, *ll*. 4-5).

On rebuttal, Company witness Anderson responded to Staff's concerns and provided a revised and updated budget for administrative costs supporting the Settlement Agreement. According to Mr. Anderson:

[66] The Company received a new license for two hydroelectric dams on the Clark Fork River in Idaho and Montana (Noxon and Cabinet Gorge). Company Witness Anderson's testimony (Exh. T-345) reviewed the relicensing process in detail, resulting in the issuance of a new license a full year prior to the expiration of the old license, which, as Staff acknowledges, is a feat never before accomplished for projects of this size.

> The revised administrative budget couples our previous 1998 estimate with over a year's knowledge and experience gained implementing the Settlement Agreement. We have now filled all staff and agency positions, and have worked closely over the past year with the Management Committee, established by the Settlement Agreement, to develop and obtain approval of the annual work plans and budgets.

(Exh. T-349, p. 10, *ll*. 10-14). Accordingly, the Company's Exhibit 352 included revised and updated figures for implementation of the Settlement Agreement amounting to $2,173,100. Upon review of this information, Staff expressed its willingness to accept the Company's proposed adjustment with respect to administrative costs associated with implementing the settlement.

Staff, however, continues to object to any use of a "balancing account" to capture variations in annual expenditures. The Company proposes to recover, through a balancing account, any actual mismatch, through time, between the expenses authorized in this proceeding and any actual expenses incurred in implementing the Settlement Agreement.[67] The Company continues to believe that this balancing account will serve to true up expenditures made for purposes of implementing the settlement; it does not "guarantee" the recovery of the O & M level of the Settlement. As explained by Mr. Falkner, credit entries in the balancing account for expense recognition would be recorded at the actual level authorized in this proceeding which is based on a normalized level of customer sales. With the credit or liability entries to the account being made based upon the authorized recovery level, the Company will still be at risk for the variability between actual sales and the normalized test year. (Exh. T-226, p. 21, *ll*. 15-20).

H. Gas Inventory Adjustment

[67] FERC Account 253, Other Deferred Debits, would accumulate a running balance that would represent either a regulatory asset or a regulatory liability. Credit entries to the account would be made for the amount of O & M that is being recovered in current rates. Debit entries would be made to the account for the actual O & M expenditures made pursuant to administration of the Settlement. Any balance in the hydro relicensing deferred balance account would be subject to refund or surcharge and would be addressed in the Company's next general rate case.

Staff, through Witness Huang, originally disallowed the Company's gas inventory adjustment. She incorrectly assumed that the inventory volume balance and the cost of inventory is controlled by Avista Energy, not Avista Utilities, and that the funds to purchase the inventory are now provided by Avista Energy — not Avista Utilities. As explained by Witness Falkner, on rebuttal, Avista Energy did not pay Avista Utilities for the current gas inventory balances; moreover, Avista Utilities continues to provide the funds for ongoing injections and receives credits for ongoing withdrawals. This is clearly reflected in Exhibit 273, which contains the applicable tariff sheets for the Natural Gas Benchmark Mechanism.[68] During cross-examination, Staff Witness Huang stated she would "accept the Company's adjustment." (Tr., p. 1454, *ll*. 14-18).

I. Bimonthly Meter Reading and Billing

Mr. Lazar, on behalf of Public Counsel, imputes an assumed reduction of costs if the Company were to provide bimonthly meter reading and billing as opposed to monthly. He proposes what is, in effect, a disallowance of approximately $2.8 million in meter reading and billing costs "as though these costs had been found by this Commission to be imprudent," as explained by Mr. Dukich. (Exh. T-84, p. 16, *ll*. 13-19). He then proposes to proform in a speculative assumption that there would be a forty-five percent savings as though it were somehow known and measurable into the future. (Id.)

On rebuttal, Company witness Hirschkorn explained the "significant negative consequences" if the Company were to change from monthly meter reading and billing to bimonthly. (Exh. T-506, p. 6, *ll*. 1-12). First of all, there would be the "financial hardship" some customers would experience resulting from the unexpected magnitude of bimonthly bills experienced during the winter months.

[68] Section 3 of Tariff Sheet 163A states: "Avista Utilities shall pay Avista Energy for the cost of gas added to inventory on a monthly basis, per the Benchmark Schedule, and will receive a credit from Avista Energy for withdrawals under the Benchmark Schedule."

(Id.).[69] Mr. Hirschkorn explained the consequences of implementing bimonthly meter reading as follows:

> Undoubtedly, if the Company implemented bimonthly meter reading and billing, significantly more customers would be forced to make payment arrangements, the number of "high-bill" complaints and "special" meter reads will increase, and the Company would see an increase in the level of past-due payments and uncollectibles.

(Exh. T-506, p. 6, *ll*. 7-12). Moreover, another result of bimonthly billing would be the likely substantial increase in the number of customers opting for the Company's monthly level-pay billing plan, as explained by Mr. Hirschkorn. (Id. at p. 6, *ll*. 13-22).[70] Because billing represents 74% of the combined meter reading and billing costs, even if meters were read on a bimonthly basis, much of Mr. Lazar's assumed savings would not be captured if a substantial number of additional customers opted for the monthly level-pay billing. (Id. at p. 6, *ll*. 18-20).

Furthermore, surveys of residential customers do not support the introduction of bimonthly meter reading and billing. In 1997, the Company conducted a survey of 200 customers, the results of which showed that over 50% of those surveyed would not favor a move to bimonthly meter reading and billings. (Id. at p. 7, *ll*. 4-10).[71] The Company also recently conducted a survey of other utilities regarding meter reading and billing, the results of which demonstrated that utilities that attempted to switch from monthly to bimonthly had a significant increase in customer complaints and past-due payments, and that much of the projected cost savings was eroded by cost increases

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[69] As explained by Mr. Hirschkorn, during the months of December, January and February, many customer bills can exceed $200; bimonthly billing could result in bills of $400 or more for many customers. While this may not be a concern of all customers who could reasonably estimate their bimonthly bill and budget accordingly, as testified to by Mr. Hirschkorn, many customers are surprised at the amount of their monthly bill during these winter months. (Exh. T-506, p. 6, *ll*. 3-7).

[70] WAC 480-100-072 requires utilities to offer residential customers a level-pay billing plan which must be offered to customers on a monthly bill basis. (Exh. T-506, p. 6, *ll*. 13-18).

[71] Of those surveyed, 20% said a move to bimonthly billing would be "not very acceptable' and 32% said it would be "not at all acceptable." (Exh. T-506, p. 7, *ll*. 5-7).

associated with addressing additional customer complaints as well as effecting changes to billing systems. (Exh. T-506, p. 7, l. 19-p. 8, l. 4).

Even those examples cited by Mr. Lazar of utilities in Western Washington that read meters and bill monthly are misdirected. First of all, many of those utilities have read meters and billed customers on a bimonthly basis for many years, so customer acceptability is less of an issue. More importantly, all of the Western Washington utilities cited in Mr. Lazar's testimony offer a monthly level-pay billing option, so many of their customers are billed already on a monthly basis. Finally, as should be obvious to all, weather in Western Washington is milder than it is in Eastern Washington, with the result that winter heating bills don't tend to be as high, nor is there as much variability in bills from month to month, as explained by Mr. Hirschkorn on rebuttal. (Exh. T-506, p. 7, *ll*. 13-18). Lastly, it is instructive to note that even Puget Sound Energy, which used to read meters and bill customers on a bimonthly basis, has installed an automated meter reading system for the majority of its customers and over two-thirds of such customers are now billed on a monthly basis. (Id. at p. 8, *ll*. 6-9).[72]

X. COST OF SERVICE AND RATE DESIGN

A. Cost of Service Methodologies

The Company has proposed an electric and gas cost of service methodology which Staff has found to be "generally acceptable" and a gas methodology which is generally consistent with prior Commission decisions. Accordingly, Staff has made use of the electric results as presented for

[72] As explained by Mr. Dukich, the proposal of Mr. Lazar is "retrogressive":

> The thinking embedded in the proposal contradicts the past twenty years of culture and business trends towards more detailed information being available quicker as opposed to Mr. Lazar's proposal to make information less available to customers with a delay. (Exh. T-84, p. 5, *ll*. 18-22).

purposes of rate design and rate spread and has made use of the gas results with one minor allocation modification.

Public Counsel, for its part, finds the gas study "consistent with previous Commission direction," but with respect to the electric study, it objects to the Company's approach to administrative and general expenses — but offers no evaluation of this approach on its own merit. ICNU and NWIGU assert that they disagree with the results of all the studies, but offer no substantive indication of what they find objectionable. (See Knox Rebuttal, Exh. T-473, p. 2, *ll*. 3-8).

For its part, the Company believes that its electric base case methodology is an improvement over the methodology previously approved for Puget Sound Power and Light in 1992, because of the inclusion of an administrative and general expense study that allows for the functional direct assignment of these costs. Also, the Company's study utilizes a definition of peak that is specifically tailored to the operational characteristics of this utility, as opposed to utilizing assumptions relevant to a different utility. (Id. at p. 2, *ll*. 19-23).

The Company requests that the Commission specifically approve the Company's cost of service methodology in this proceeding because it will provide direction with respect to a methodology that can be used consistently over time for purposes of rate spread and rate design.

B. Electric Rate Spread

As explained by Mr. Hirschkorn, on behalf of the Company, the Company's proposed rate spread results in a movement of one-third toward unity, as does the joint proposal of Staff and Intervenors as set forth in Exhibit 659. However, the joint proposal of Staff and Intervenors will result in less movement toward unity if any amount less than the Company's entire revenue request is approved. (Exh. T-506, p. 3, *ll*. 10-14). Exhibit No. 507, at page 1, provides a comparison of the joint proposal rate spread compared with the Company's proposal using various revenue increase examples and demonstrates that the Company's proposed rate spread would result in a one-third movement toward unity under all of the examples covering a wide array of revenue requirement changes, while the joint proposal of Staff and Intervenors results in a lesser movement toward unity as the overall revenue requirement decreases. (See Exh. T-506, p. 3, *ll*. 17-22). The Company's position is that a one-third movement toward unity be the minimum amount of movement that the Commission should consider in this case, regardless of the overall revenue requirement granted. (Id. at p. 4, *ll*. 2-4). Also, as shown in Exhibit 507, at page 1, the rates for most of the Company's commercial and industrial customers (Schedules 11 and 21) are substantially higher than the cost to provide service, creating a concern from a competitive standpoint as the Company "faces competitive pressure from surrounding public utilities," as explained by Mr. Hirschkorn. (Id. at p. 4, *ll*. 5-13).[73]

In response to Mr. Lazar's suggestion that the Commission should rely on a "revenue to cost ratio" instead of a rate of return comparison, the Company prepared Exhibit 507, page 2, which provides the present "revenue to cost ratio" as well as the Company's proposed ratios. This demonstrates that the "revenue to cost ratio" for Residential Service Schedule1 would still be less than 90%, and the ratios for Schedules 11 and 21 would be 119% and 117%, respectively. (Id. at p. 4, *ll* 19-p. 5, *ll*. 5). Therefore, as testified to by Mr. Hirschkorn, "regardless of whether the Commission uses a rate of return comparison or a revenue-to-cost comparison, the conclusion is the same — the rates for Schedules 1, 11, and 21, are not within a reasonable range relative to costs, and this proceeding presents an opportunity to at least bring those rates closer to that range." (Id. at p. 5, *ll*. 2-5).

C. Electric Residential Basic Charge

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[73] Mr. Hirschkorn, on rebuttal, cited as an example, a new large commercial customer (3,000,000 kwhs annually) located in Othello which chose to take service from Big Bend Electric rather than from the Company, because their annual bill was projected to be $30,000 less under Big Bend's rates. (Exh. T-506, p. 4, *ll*. 8-14). According to Mr. Hirschkorn, "the Company would have had virtually no incremental distribution investment required to serve this customer, and the revenue received would have provided a measurable contribution to system costs." (Id.).

Mr. Lazar, on behalf of Public Counsel, recommends a residential basic charge of only $3.82 per month in his direct testimony, based on his estimate of costs that he believes should be recovered in the basic charge, which includes only 55% of Company meter reading and billing costs. (Exh. T-686, p. 2, *ll*. 5-7 and p. 3, *ll*. 13-23). In Mr. Lazar's errata to his testimony, his cost estimate of $3.82 was corrected to a figure of $4.59 based on a significant error in his calculation that was discovered by the Company. However, Mr. Lazar goes beyond a mere correction and actually reduces his proposed basic charge through additional testimony in his errata from $3.82 to $3.75, no longer relying on his proposed methodology provided in his direct testimony. Further, Mr. Lazar believes that 45% of the Company's meter reading and billing costs are usage-related, because if customers usage did not vary from month to month, it would not have to read meters and bill customers each month. Company Witness Hirschkorn explained why he did not agree with Mr. Lazar's assumption that a portion of meter reading and billings costs are usage-related:

> The costs associated with meter reading and billing do not vary with the amount of energy customers' use. The meter reading and billing cost per customer is the same whether a customer uses 600 or 3,000 kwhs a month. Mr. Lazar's proposal would have a customer who uses 3,000 kwhs during a month pay more than twice the amount for meter reading and billing as a customer using 600 kwhs during a month, even though the cost of performing those services for both customers is the same.

(Exh. T-506, p. 9, *ll*. 12-17). Moreover, the Company is unaware of any prior Commission decision supporting Mr. Lazar's contention that meter reading and billing cost are usage-related and should be recovered through energy charges. (Id. at p. 9, *ll*. 21). If, in fact, Mr. Lazar's method of computing the basic charge included 100% of the Company's actual meter reading and billing costs as a customer-related cost, his proposed basic charge would be $5.71 per month — in excess of the $5.00 proposed costs to be recovered in the basic charge in this case. (Id. at p. 10, *ll*. 1-4).[74] As

[74] So long as the Commission in its order includes 100% of the Company's actual meter reading and billing costs and used whatever rate of return was ultimately approved by it in this case, the Company would accept the resulting calculation of the basic charge as a reasonable level in this

pointed out by Mr. Lazar, "These are the customer-related costs as determined by the Commission in Docket U-789-2688-T, and reaffirmed in proceedings to which this Company has been a party since that time such as UE-920499." (Exh. T-686, p. 3, *ll*. 16-18). Mr. Hirschkorn pointed out in his direct testimony that Puget Sound Energy presently has a residential basic charge of $5.28, also in excess of the $5.00 charge proposed by the Company. (Exh. T-490, p. 13, LL. 19-20).

D. Electric Residential Rate Design

The Company proposes to reduce the residential three-block rate structure to a two-block structure. Mr. Lazar, on behalf of Public Counsel, objects to this proposal and testifies in favor of the retention of the three-block structure. Mr. Lazar erroneously assumes that the Company's low cost hydro resources are being allocated to serve base load consumption (the first 600 kwhs of usage under the Schedule) while the Company's highest cost resources are being allocated to the present tail block (over 1,300 kwhs of usage). As explained by Mr. Hirschkorn, however:

> Mr. Lazar's proposed allocation of resources has absolutely no relationship as to how these resources are used to serve customer load requirements. In fact, the Company's higher costs generating resources are actually used to serve customers' base-load usage requirements throughout the year while low-cost hydro resources are used to serve more variable weather-sensitive consumption.

(Exh. T-506, p. 11, *ll*. 3-7). In fact, pages 3 and 4 of Exhibit 507 show actual operation of the Company's generating resources and system load requirements for January 10, 2000, and July 28, 1999, demonstrating that most of the residential weather-sensitive usage which Mr. Lazar assigns high cost resources to is actually met with the operation of the Company's lowest cost resources. Furthermore, as explained by Mr. Hirschkorn, conversely, most of the residential base-load usage

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proceeding, as acknowledged by Mr. Hirschkorn. (Exh. T-506, p. 10, *ll*. 9-13).

which Mr. Lazar assigns low cost resources to is actually met with higher cost resources. (Id. at p. 11, *ll*. 14-17).[75]

Finally, Mr. Lazar erroneously assumes that electric space-heat customers have higher distribution costs than customers without electric space-heat. In fact, as explained by Company Witness Hirschkorn, most of the Company's distribution costs are fixed and would "be relatively the same regardless of whether a customer uses electric space-heat or not." (Id. at p. 12, *ll*. 11-17). (Moreover, since most distribution costs are recovered through the existing energy charge, an electric heat customer provides a substantially higher contribution to those costs than a non-electric heat customer). (Id. at p. 12, *ll*. 11-17).

Finally, Mr. Lazar erroneously assumes that electric space-heat usage will increase under the Company's proposed two-block rate structure. In the expert opinion of Company Witness Hirschkorn, however, customers "react to changes in their total bill, and they know if they use more electricity, their bill will be higher, and vice-versa." (Id.).[76]

E. Gas Rate Spread

The Company is in agreement with the joint gas rate spread proposal of Staff and Intervenors as testified to by Staff Witness Russell, which would spread the overall revenue increase based on a uniform (equal) percentage of present margin under each of the schedules, except for Interruptible

[75] Furthermore, because the amount of hydro generation can be dispatched on a real-time basis by controlling the amount of water passing through turbines, these generating units are well suited to serve varying load requirements, as explained by Mr. Hirschkorn. (Exh. T-506, p. 11, *ll*. 18-p. 12, *ll*. 2). Thermal generating units, however, are designed to operate more efficiently on a continuous basis, and are generally not "ramped up and down to serve varying load requirements." (Id.).

[76] Only 21% of the Company's residential customers use electricity as their primary source of space heat and many of these customers do not have the ability to switch to natural gas. Accordingly, retention of the three-block structure only creates "additional financial pressure" on these customers to heat their home. (Exh. T-506, p. 13, *ll*. 11-17).

Service Schedule 131 and High-Volume Transportation Service Schedule 148 — both of which would receive no increase. (Exh. T-506, p. 5, *ll*. 8-16).

F. Gas Residential Basic Charge

The Company proposes an increase from $4.00 to $5.00 per month for the gas residential basic charge. Public Counsel, however, argues for the retention of the present gas residential basic charge of $4.00 per month. While the Company's proposed charge of $5.00 per month would recover a small portion (less than 20%) of gas service costs (i.e., cost of gas service lines) in the basic charge, Mr. Lazar would not include any such service costs in the basic charge. If, in fact, the Company recovered all gas service costs through the basic charge, along with the cost of meters, meter reading and billing, the charge would be $10.17 per month — as opposed to the $5.00 per month being proposed in this proceeding. (Exh. T-506, p. 15, *ll*. 16-21).

Mr. Lazar, on behalf of Public Counsel, argues that the cost of gas service lines should not be recovered through the basic charge because he believes that residential gas customers with very low usage could somehow be charged twice for gas service — once through the Contribution in Aid of Construction at the time the service extension is installed, and then again through the monthly basic charge. According to Mr. Hirschkorn, however, Mr. Lazar would be correct only if the Company had a significant number of low use gas customers (i.e., non-space or water heat) and all gas service costs were recovered through the basic charge, neither of which are true. The fact remains that residential customers requesting natural gas service do so primarily to heat their homes — not simply for cooking or for some other low-use appliance; accordingly, they are not required to pay a Contribution in Aid of Construction for service extension at the time of installation. (Exh. T-506, p. 14, *ll*. 17-p. 15, *ll*. 1). Further, the Company's proposed basic charge of $5.00 would recover less than 20% of gas service line costs.

G. Gas Rate Design

The Company does support Staff's proposed four-block rate structure for Interruptible Service Schedule 131. It agrees that Mr. Russell's proposed rate design provides an additional financial incentive for customers to take interruptible service. (Exh. T-506, p. 16, *ll*. 13-18).

Next, while the Company does support the proposed five-block rate design for Transportation Schedule 146, as proposed by Mr. Russell and Mr. Schoenbeck, it does differ with Mr. Schoenbeck's proposal to reduce the Company's proposed rates for the first two blocks under Schedule 146. While Mr. Schoenbeck is concerned with the potential percentage increase in the transportation bill for smaller customers under the Schedule, the resulting percentage increase represents only a relatively small portion of the customers' total gas bill as explained by Mr. Hirschkorn. (Exh. T-506, p. 17, *ll*. 18-p. 18, *ll*. 2). Furthermore, the proposed five-block structure, in and of itself, reduces the potential increase to the smaller customers as compared to the Company's originally proposed four-block structure. (Id.). Finally, as noted by Mr. Hirschkorn, smaller customers served under Schedule 146 "have enjoyed a significant distribution cost savings for years, and it is time to restructure the rates to significantly reduce this inequity." (Id.).

Finally, neither the Company nor Staff believe it necessary to add an additional rate block to Schedule 121, if higher rate levels are established for the first two blocks under Transportation Service Schedule 146. This would not be necessary in order to reduce the potential margin loss resulting from Schedule 121 customers switching to transportation service. (Id. at p. 18, *ll*. 3-9).

XI. ENERGY EFFICIENCY EXPENDITURES

The Company respectfully requests a finding of prudency for the energy efficiency expenditures made between January 1, 1995 and December 1998 under Schedules 91 and 191. (T-315, p. 2). The Commission approval in Docket Nos. UE-941377 and UG-941378, reiterated in Docket No. UE-961309, requires that the Company demonstrate the prudence of the Company's energy efficiency programs and expenditures at the time of a general rate case. Avista has included such demonstration in this rate case, the first rate case since the inception of the tariff riders.

No party contested the Company's request. Staff Witness Joelle Steward supported this request. (T-663, p. 77, *ll*. 13-14). The Northwest Energy Coalition's Witness Nancy Hirsh also supported the Company's analysis in support of prudency. (T-649, p. 5., *ll*. 7-21).

Staff also recommended that the tariff rider balance should be reduced to a reasonable level approaching zero by mid-2001; otherwise, the Staff suggests that the Company be directed to, in essence, reduce its tariff rider. (T-663, p. 7, *ll*. 4-17). The Company does not take issue with this recommendation based on Staff's clarification of "reasonable level," through its response to Data Request No. 177.

XII. LOW-INCOME CUSTOMER PRACTICES

The Spokane Neighborhood Action Program (SNAP) presented the testimony of Mr. Roger Colton, who recommends a "collaborative", in order to consider potential Company programs beneficial to low-income customers. (See Exh. T-726, p. 4). He does not otherwise recommend or advocate any specific low-income programs for purposes of adoption in this proceeding.

Through the testimony of Company Witness Folsom, the Company explained why it does not believe a "collaborative" for Avista Utilities should be convened at this time:

> Between Avista Utilities' low-income energy efficiency programs, its CARES Program, and Commission-governed reconnection policies, the Company will spend approximately 1% — a number used as a general goal for low-income programs — of its annual jurisdictional retail revenue on low-income customers in the 2001 rate year. Furthermore, Avista Utilities' rates, both current and proposed, are already below any rates resulting from utility discount programs throughout the United States to my knowledge. Taken as a whole, and by these measures, this makes Avista Utilities one of the most "low-income friendly" utilities in the country.

(Exh. T-326, p. 2, *ll*. 8-15). Mr. Folsom elaborated on the Avista Utilities' current support of low-income initiatives. In 1999, Washington low-income customers received over $1 million in energy and fuel efficiency assistance, and an additional $500,000 was pledged by Avista Utilities to low-income energy efficiency efforts for each of the next two years. In addition, Avista Utilities dedicates four full-time customer service representatives who assist customers in financial needs through its CARES Program. These representatives direct customers to Community Energy Assistance Programs and arrange for payment plans. As such, these representatives are advocates for low-income customers. In 1999 alone, Avista Utilities made 159,069 payment arrangements for Washington customers; had disconnection time periods of less than four hours on average; and wrote off $1,633,823 in unpaid Washington residential accounts, of which $816,000, or one-half originated from low-income customers. (Id. at p. 3, *ll*. 11-18).

In total, this effort represents a financial commitment of over 1% of Washington retail revenue — which is in line with Mr. Colton's call for a "1% wires charge" to fund low-income programs. (Id. at p. 3, *ll*. 11-22).

Furthermore, Avista's rates to low-income customers are already less than any rates resulting from any rate discount programs offered by any other utilities, as testified to by Mr. Folsom. (Id. at p. 4, *ll*. 5-8). Stated differently, customers of utilities in states that have adopted formalized low-income programs experience rates that are already above the national average and are significantly higher than Avista Utilities' rates. (Id. at p. 5, see also Tabulation of Residential Rates appearing at p. 6 of Exhibit T-326).

Mr. Colton's own metric for unsustainable energy burdens for low income customers apparently ranges from 6% to 8% of income. And yet, Avista Utilities' low-income customers (i.e., those at 125% of the federal poverty level) experience electric power burdens of 3 % for households of three or four people. This prompted Company witness Folsom to observe that Avista Utilities' current or proposed rates do not "lead to an unaffordable energy burden for the Company's low-income customers," according to Mr. Colton's own standards. (Exh. T-326, p. 5, *ll* 6-10).

In summary, the Company already provides aggressive energy and fuel efficiency assistance, as well as specialized customer service dedicated to financially distressed customers. If, however, a collaborative process is directed by this Commission, the Company recommends that it be a state-wide process for the purpose of examining low-income issues, as the same may be impacted by existing Commission collection and disconnection rules and practices.

XIII. CONCLUSION

Sound principles of ratemaking require that the Company be afforded substantial rate relief, based on compelling evidence of record.

RESPECTFULLY SUBMITTED this _____ day of August, 2000.

AVISTA CORPORATION

By: ____________________________________

DAVID J. MEYER
Senior Vice-President and General Counsel
For Avista Corporation

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