Exhibit ___(JL-T-RR)

Before the
Washington Utilities and Transportation Commission

Avista Corporation General Rate Case
Docket Nos.
UE-991606
UG-991607

Direct Testimony of

Jim Lazar
Consulting Economist

On Behalf of
Public Counsel

Revenue Requirement Issues

May 5, 2000

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I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, address, and occupation, and summarize your utility regulation experience.

A. Jim Lazar, 1063 Capitol Way S. #202, Olympia, Washington, 98501. I am a consulting economist specializing in utility rate and resource issues. I have been engaged in utility rate consulting continuously since 1979. During that time, I have appeared before many local, state, and federal regulatory bodies, authored books, papers, and articles on utility ratemaking, and have been a faculty member on numerous occasions at training sessions for utility industry analysts. I have appeared before this Commission on more than forty occasions in proceedings involving each of the gas and electric utilities regulated by the Commission. I have served as a consultant to this Commission on several occasions, including participation in BPA rate proceedings, assistance with technical studies, and staff training.

I have familiarity with Avista beginning with my appearance as a witness in Cause U-78-05, a generic rate design proceeding commenced in 1978, and have participated in virtually every Washington Water Power rate proceeding since that time. Of particular importance to this proceeding, as a legislative staff member in 1979, I was one of the originators of the "bonus rate of return" concept embodied in RCW 80.28.025 under which the Company is seeking compensation for the Kettle Falls generating project, and I was an expert witness for Public Counsel in the 1988 Power Cost Adjustment proceeding, Cause U-88-2363-P.

Q. What topics are you covering in your testimony?

A. I am the overall policy witness for Public Counsel in this proceeding.

I address a number of revenue requirement issues in this testimony. In my second piece of testimony, Exhibit JL-T-RD, I address electric and gas rate design issues. Finally, I am a part of two panels together with witnesses for the WUTC Staff and the Industrial Customers of Northwest Utilities on electric and gas rate spread issues.

II. SUMMARY OF FINDINGS

Q. Please summarize your findings in this portion of your testimony.

A. First, with respect to Administrative and General Expenses, I show that the Company's Administrative and General Salaries have grown by 239% since the last general rate case, compared with general inflation of only about 60% and system customer and sales growth of only about 21%. This analysis results in a reduction in electric and gas operating expense of $4.2 and $1.1 million respectively.

Second, I address the corporate name change, both from the perspective of the charges that the Company proposes that ratepayers bear, as well as an estimate of the amount that should be attributed to utility revenues from the use by the subsidiaries of the corporate name. This increases electric and gas operating revenue by $2.2 million and $560,000 respectively, and eliminates the Company's proposed amortization of name change expenses.

Third, I compute a revised level of production depreciation expense which better matches the market value of the Company's production plant to the depreciated book value of that plant. This reduces test year operating expense by $2.7 million.

Fourth, I speak to the proposal by the Company to impute a higher rate of return to the Kettle Falls Generating Station than to other plant, and show why that facility is not eligible for the rate of return bonus established by RCW 80.28.025. This affects the calculation of the rate of return.

Fifth, I address the Company's proposal to charge customers for monthly meter reading and billing expenses, even though the Commission's rules only provide a requirement for bimonthly meter reading and billing. As a part of this, I question several of the billing inserts the Company has included in customer bills as unrelated to the provision of electric service. This reduces test year operating expense for electric and gas operations by $1.5 million and $1.0 million, respectively, with partially offsetting increases to electric and gas rate base of $4.2 and $2.1 million.

Sixth, I demonstrate that Avista has not achieved levels of management efficiency that would justify their proposal for a 25 basis point addition to the allowed return on equity. In fact, I show that Avista has the highest operating costs (apart from power supply) of any of the major utilities in the Northwest. This affects the calculation of the allowed rate of return.

Seventh, I address a number of reasons why the proposed Power Cost Adjustment should not be allowed. Essentially both the proposed mechanism and the reasons why it is improper are very similar to what they were 12 years ago when the concept was originally rejected.

Finally, I address how the Commission should treat Centralia replacement power costs, should the Centralia plant be sold. This analysis takes into account the information which contributed to the Commission's decision in Docket UE-991255.

Q. Are these the only revenue requirement adjustments which Public Counsel is supporting in this proceeding?

A. No. Mr. Stephen G. Hill addresses the cost of capital in his testimony and exhibits. Mr. Robert L.C. Damron calculates the revenue requirement effect of Public Counsel's adjustments and incorporates the level of depreciation expense reflected in Mr. DeFelice's revised exhibits. Finally, Public Counsel will review the adjustments proposed by Staff, ICNU, other parties, and the Public, and may adopt some of those adjustments in the brief submitted at the close of this proceeding.

III. REVENUE REQUIREMENT ADJUSTMENTS

Q. How have you organized your proposed adjustments to the Company's requested revenue level?

A. I address each adjustment separately, and there is a separate exhibit for each adjustment requiring a calculation. Public Counsel Witness Robert Damron has the responsibility for presenting each of these adjustments in Results of Operation format, but I am responsible for the underlying policy analysis for each adjustment.

A. Administrative and General Salaries

Q. What is the amount of your proposed adjustment to Administrative and General salaries?

A. I recommend that test year electric operating expense be reduced by $4.16 million, and gas operating expense be reduced by $1.06 million, as detailed on Exhibit ___(JL-RR-1).

Q. What is the basis of this adjustment?

A. I provide analysis on the inordinate growth of Administrative and General Salaries, which are now more than three times the level that existed at the time of the Company's last litigated electric rate proceeding. Mr. Damron and I both provide analysis of the Company's Administrative and General Expenses, and our testimony should be considered complementary. My testimony addresses the rate of increase in these expenses compared with inflation and load growth on the system, while Mr. Damron's addresses the relationship between growth in Administrative and General Salaries and growth in non-regulated operations.

Q. Please describe the results of your analysis.

A. Exhibit __ (JL-RR-1) shows the level of A&G salaries in the last electric rate case, an adjustment for inflation and customer growth, and shows that if electric A&G salaries had grown at the same rate as inflation plus customer growth, they would total $5.6 million today. The Company is requesting recovery of $9.7 million. I recommend that the difference -- the excess over $5.6 million -- be disallowed.

Q. What are the apparent components of the excessive growth in A&G salaries?

A. There appear to be several components. First, executive compensation has simply soared at this Company, and there is no evidence that the management today is better than the management in the past. Second, the Company has diversified its operations, and executive compensation seems to be reflecting non-utility elements. Finally, there is the question of Mr. Matthews "signing bonus" which was explored during cross-examination.

Q. How does compensation to the company's executives compare with comparable management salaries in the public sector?

A. The compensation to Mr. Matthews is approximately 8 times as great as the compensation received by the governor of the state of Washington, a person who is responsible for managing a $20 billion business with over 100,000 employees. Mr. Matthews compensation is 8 times as great as the general managers of similarly sized utilities in the state of Washington such as Seattle City Light, Tacoma Public Utilities, Snohomish PUD, and Clark PUD. The Company's second-highest paid employee earns about twice as much as the second-highest paid employee at the similar sized utilities.

Q. Are you suggesting that high management salaries are inappropriate for a diversified business such as Avista?

A. I do not address the appropriate compensation levels for the non-regulated business operations. I am only suggesting that ratepayers should not be forced to pay dramatically more for utility managers than they pay for other managers at comparable levels of responsibility. In the past, Washington Water Power executives were paid somewhat more than public managers, but not the huge differences we see today.

Second, the amount of management time being devoted to non-regulated operations has increased, since those operations, in the test year, accounted for more than 80% of total operating revenues. While very expensive management may be justified for non-regulated operations, it is not necessary or appropriate to run an electric utility.

Q. How have you computed your proposed adjustment?

A. I have taken the electric administrative and general salaries from the last rate proceeding, and escalated these at the compound rate of inflation plus customer growth. This results in a 42.7% disallowance of the Company's proposed electric administrative and general salaries. I apply the same factor to the Company's proposed gas administrative and general expenses. As noted above, this is shown in Exhibit ___(JL-RR-1). Mr. Damron uses this information as an input to his results of operations calculations.

Q. Did you consider other methods?

A. Yes, I considered a formal allocation model to assign costs to the unregulated operations, similar to what the Commission has ordered in the past for other utilities. Because the Company's non-regulated operations are in a state of flux, I decided to use the inflation plus growth approach. However, Mr. Damron's analysis shows that the growth in administrative and general salaries appears to be more closely correlated with the growth in non-regulated operations than with any change in utility operations.

B. Corporate Name / Franchise Fees

Q. What has the Company requested with respect to the corporate name change?

A. The Company has requested that ratepayers bear the cost of changing the name of The Washington Water Power Company to Avista Corporation. The effect of this is shown in Exhibits 241 and 242.

Q. Should the Company's proposed approach be accepted?

A. No. The name change is of no value to ratepayers, and, if anything, causes confusion for customers familiar with the Washington Water Power name. That name had over a century of familiarity.

Q. What argument has the Company offered for changing the name?

A. The two arguments are that the previous name was confused with the Washington Public Power Supply System, and that the diversified operations of the Company needed a name with less focus to it.

Q. Are either of these arguments justifications for charging electric consumers for the name change?

A. No. First, WPPSS has already changed its name to Energy Northwest, so that confusion has been eliminated. Second, any value to diversified operations should be charged to those activities, not to the provision of regulated electric and natural gas service.

Q. What value does the corporate name provide to non-regulated operations?

A. By associating the competitive operations of the corporation with a stable, ongoing utility business, I believe that Avista adds a level of assurance to customers of the non-regulated business that the company will be around for the long haul. In this age of upstart dot.com businesses soaring and crashing, a high-tech subsidiary associated in the customer's mind with the stability of an electric and gas utility is more likely to be able to attract customers.

Q. Should the value that the utility brings to the non-regulated operations sharing the corporate name be compensated by those non-regulated operations?

A. Yes, and that precedent has been established before this Commission in Docket UG-931405, involving the use of the corporate logo and association by non-regulated subsidiaries of the Washington Energy Company. In that docket, the Commission approved a transfer of 1.5% of the gross revenue of the non-regulated operation to the utility in exchange for the use of the corporate name.

Q. Do you recommend a similar procedure in this proceeding?

A. Yes, but in view of the amount of revenues during the test year of the non-regulated operations, I recommend a smaller level of franchise fees be attributed to utility operating income. I recommend that one tenth of one percent of energy trading revenues, plus one percent of all other non-regulated revenues be treated as revenues to the utility in this proceeding. Exhibit __(JL-RR-2) shows the effect of this calculation. This increases electric revenues by $2.2 million, and increases gas revenues by $561,000.

Q. What is the net effect of your two recommended adjustments?

A. Eliminating the name change expense decreases expense, while attributing franchise fees to the non-regulated operations for the use of the corporate name increases revenues. Mr. Damron uses the adjustments in my exhibit as input data to his results of operations calculations.

C. Production Depreciation Expense

Q. Please describe the adjustment you proposed to production depreciation expense.

A. This adjustment defers collection in rates of all depreciation expense for the Company's hydroelectric power plants. It also increases the production rate base slightly to reflect the reduced collection of depreciation expense. This adjustment decreases electric depreciation expense by $2.7 million as set forth in Exhibit ___(JL-RR-3).

Q. What is the reason for this adjustment?

A. The market value of these resources exceeds the depreciated book value by a factor of <u>seven</u>, meaning that ratepayers have already paid very significant amounts of excess depreciation. As I explain below, the Commission addressed this issue in Docket No. UE-991255, and this adjustment is needed to mitigate the concern the Commission postulated, that a future Commission may not be able to capture stranded benefits of low-cost power plants for the benefit of ratepayers who have funded these resources.

Q. What is a reasonable estimate of the market value of the hydroelectric power plants?

A. That question can only be answered definitively in the marketplace, and I do not suggest that these resources be sold, but the projects are certainly worth an amount greatly in excess of book value. In the Company's Cost of Service Study, Ms. Knox used "replacement cost less depreciation" for the hydro and thermal plants as the basis of her classification of production and transmission plant. That analysis shows a value for these facilities of $1,355 per kilowatt, compared with a depreciated book value of hydroelectric plant of about $181/kw, or <u>seven and one-half times</u> the depreciated book value. There is no justification for accumulating additional 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.

Q. What is the problem that the Commission had to address in Docket UE-991255?

A. In Docket UE-991255, the Centralia plant was proposed to be sold at a price in excess of the original cost, and far in excess of depreciated book value. While the record in that proceeding strongly suggested that the plant was worth more than the selling price over the remaining plant lifetime, the Commission approved the sale, provided that the first application of the proceeds was to reimburse ratepayers for the excess depreciation paid on the plant.

The Commission indicated that it approved the sale, in spite of apparent negative economics in the long run, in part because of a concern that a future Commission would not be able to capture the long-run benefits of plant ownership for consumers. As the Commission stated in its order:

> "The fact that the facilities are selling for an amount greater than original cost is evidence that the facilities have an increasing, not a decreasing, value, as an asset in a competitive wholesale generation market. This increased value is greater than the depreciation paid by ratepayers. Thus, a portion of the gain equivalent to the difference between net book value and original cost should be returned to ratepayers, as they have, in effect, overpaid necessary depreciation."
>
> [UE-991255, Order, Paragraph 82, emphasis added]

> "We are not expressing a view on the wisdom of legislative retail electric restructuring, but we are sobered by indications that such a change might not include capturing power benefits for ratepayers from plants that become deregulated."
>
> [UE-991255, Order, Paragraph 52]

I can only interpret the Commission's decision as suggesting that it is appropriate to take steps to avoid creating stranded benefits. Collecting additional depreciation expense from ratepayers for the Company's hydroelectric facilities would likely create additional stranded benefits.

Q. Have you considered a similar approach for the thermal generating facilities?

A. Yes, but I am not proposing parallel treatment at this time. The Company's exhibits show that the market value of the thermal plants is about three times the book value, compared with more than seven times for the hydroelectric plant. Much of this is driven by Centralia, which has a depreciated book value of less than $100/kw. With the potential sale of Centralia, the Company would be left with relatively high-cost thermal resources in Colstrip 3/4 and Kettle Falls. While these have a depreciated book value much lower than the $1,380/kw the Company assumed as the "replacement cost depreciated," the recently rejected sale of Colstrip 3/4 by Portland General Electric was at a price about half of the postulated replacement cost. Neither of these plants is currently cost-effective compared with short-term market prices, and it is less certain that there are stranded benefits at this time. For those reasons, I am not proposing that depreciation collection be halted on the thermal plants at this time.

Q. What is the effect of this adjustment on rates?

A. Depreciation expense is reduced by $2.7 million, while rate base is increased somewhat due to the lower depreciation accrual but faster buildup of the deferred tax balance. Mr. Damron calculates these other changes and their effect upon results of operation.

Q. Does your proposal deny the shareholders a return on the investment in these generating facilities?

A. No. Because the depreciation expense collection is deferred, the rate base remains a bit higher than originally proposed by the Company. The Company continues to earn a full fair rate of return on the utility plant that is used and useful.

Q. What will happen to the plant in service, accumulated depreciation, and fair market value of the hydroelectric plant during the deferral period?

A. Plant in service will continue to grow as improvements and betterments are made to the power plants. Accumulated depreciation will remain unchanged. Fair market value cannot be predicted with certainty, but the value of generating plants will generally go up with inflation, and down as the plants age, subject to other changes caused by technological obsolescence and environmental factors.

Q. How long do you propose that this depreciation collection be deferred?

A. The objective of depreciation accrual is to return the investment in the plant to the Company over its lifetime. Since the major hydro facilities were recently relicensed for an additional 50 years, that lifetime is far into the future. This adjustment serves to incrementally allow the gradual convergence of depreciated book value and fair market value, so that the amount of stranded benefit to be addressed in the future is mitigated. I recommend that the Company be permitted to resume collection of depreciation expense in current rates if and when the fair market value of the power plants more closely approximates depreciated book value. Given the huge gap presently, this will be many years from now. If and when the Company believes that convergence has occurred, and that market value and book value are aligned, it would be appropriate for the Commission to consider resumption of the collection of this depreciation expense from ratepayers.

Q. Does this adjustment conflict with the agreement on depreciation rates reached between the Company and WUTC Staff?

A. No, it does not. This adjustment deals only with the timing of collection of depreciation expense on hydroelectric facilities. It does not seek to second-guess the mechanical calculation of the "remaining life" concept that underlies estimation of depreciation rates. Public Counsel does not object to the agreement, as expressed in Mr. Damron's testimony. This is a separate issue, dealing with when the depreciation expense should be collected.

D. Kettle Falls Bonus Rate of Return

Q. What is the Company's request with respect to the rate of return on the Kettle Falls generating plant?

A. Mr. Dukich proposes that an additional 2% rate of return be applied to the equity investment in Kettle Falls, based on the principles in RCW 80.25.025.

Q. What is your familiarity with this statute?

A. This was originally introduced in the 1979 legislative session. As a member of the Washington State Senate staff, I was one of the legislative analysts who drafted the original legislation. It ultimately passed in the present form in 1980. During that year, I was a registered lobbyist and testified in support of the passage of this statute. Washington Water Power, on the other hand, was apparently virtually unaware of its existence. In the Company's 1981 rate proceeding, U-81-15, the Company failed to even ask for the bonus rate of return for its (eligible) weatherization investment; staff and intervenors had to remind the Company of this incentive. It is hard for the Company to argue that the "incentive" affected the Company's decision to construct Kettle Falls in 1981 when it was apparently not even aware of the legislation.

Q. Why is Kettle Falls ineligible for this bonus rate of return?

A. The statute limits the incentive to measures which are cost-effective. The specific language in RCW 80.25.025 reads:

> "Measures or projects encouraged under this section are those for which construction or installation is begun after June 12, 1980 and before January 1, 1990, and which, at the time they are placed in the rate base, are reasonably expected to save, produce, or generate energy at a total incremental system cost per unit of energy delivered to end use which is less than or equal to the incremental system cost per unit of energy delivered to end use from similarly available conventional energy resources which utilize nuclear energy or fossil fuels and which the gas or electric company could acquire to meet energy demand in the same time period."

Q. Is Kettle Falls cost-effective as defined by the statute?

A. No, and the Commission explicitly addressed that issue in its decision in Cause U-83-26, when Kettle Falls was placed into service. At page 13 of its order, the Commission stated:

> "The 1982 study showed that Kettle Falls was no longer the lowest cost alternative."

The Commission noted, however, that $23 million had been sunk by 1982. That was one reason why the Commission felt that it might have made sense that the Company did not abandon it. That is perhaps an appropriate standard for allowing the investment into rate base, which is the decision that was before the Commission in Cause U-83-26. However, the statute on the bonus rate of return is clear that the cost-effectiveness test is imposed at the time the resource is placed into rate base. That time was in 1984, not in 1981 or 1982.

Q. What decision did the Commission make on Kettle Falls in 1984?

A. The Commission considered four alternatives at page 16 of its order in Cause U-83-26. The first was to disallow a set percentage. The second was to disallow all costs incurred after 1982. The third was to disallow AFUDC. A final option was to disallow the difference between the actual cost of the plant and the cost of the lower-cost alternative. The Commission elected to disallow 10% of the cost, which allowed the Company to recover the original project cost estimate, but not the cost overrun.

Q. Was Kettle Falls cost-effective when it was placed in rate base?

A. No. The cost allowed in rate base of $80.5 million was around $1,900 per kilowatt, or 25% - 50% more than the cost of coal plants which entered utility rate bases at that time. The cost of power when it entered rate base was in excess of market prices then, and remains in excess of market prices today.

Q. What was the cost of power from Kettle Falls when it entered rate base, compared to market prices at that time?

A. As shown in Exhibit ___ (JL-RR-4) at page 3, the original rate base and rate of return, plus operating costs in the first full year of operation created a cost of power of more than 125 mills/kwh ($.125/kwh). In reaching its decision in Cause U-83-26, the Commission compared Kettle Falls to natural-gas fired power, and found that the costs were excessive. As a practical matter, if natural gas hydro-firming plants had been chosen (as Puget did), most of the energy would have come from low-cost hydro in above-average water years. The only way to reasonably measure that opportunity cost is the spot market. In my Exhibit ___(JL-RR-4) on page 1, I have shown the spot market prices for 1986-98, plus an adder for capacity which the Company estimated in the Centralia proceeding, but which is approximately equal to the carrying costs of new gas turbines which could have been built in the mid-1980's (Puget's units cost around $200/kw to build, or $40/kw/year, or $3.50/kw/month, which I have used).

Another reasonable estimate of the market value of long-term firm power at that time was the price of the contract the Commission approved in Docket U-83-57 between Pacific Power and Black Hills Power and Light for power from Colstrip #3 (which, as an owner, WWP could have purchased as easily as did Black Hills) at a price of 37 mills/kwh ($.037/kwh). This was for a long-term firm agreement; short-term commitments carried much lower prices. The Kettle Falls and Black Hills proceedings were before the Commission simultaneously. By no means was the Kettle Falls plant cost-effective compared with available resources at that time.

Q. Is the Kettle Falls plant cost-effective today?

A. No. As shown in Exhibit __ (JL-RR-4) at page 2, the power from Kettle Falls in the test year will cost around 43 mills/kwh ($.043/kwh), based on Mr. Hill's recommended cost of capital. This is about one and one-half times the market value of power that Avista witness Mr. Johnson testified to for the Company in the Centralia proceeding, Docket UE-991255 in Exhibits 304 and 332, as replicated in my Exhibit ___(JL-RR-6). It can also be compared to the replacement costs for Centralia that the Company has estimated in Exhibit C-194 in this proceeding.

Q. Based on this analysis of Kettle Falls cost-effectiveness, what conclusion should the Commission reach on the bonus rate of return?

A. Page 1 of Exhibit ___(JL-RR-4) shows that Kettle Falls did not meet the test of the statute when it went into service, because the cost was far above the then-comparable cost of power.

The Commission did not grant the bonus rate of return at that time. It did not meet that test in the Company's 1984 and 1985 rate cases either, and the Commission never allowed that increment into rates. It does not meet the cost-effectiveness test today.

Q. Is this proposed treatment consistent with the intent of the statute?

A. Yes, I believe it is. The intent of the statute was to reward companies which were able to find cost-effective energy conservation and renewable resources. The Kettle Falls plant is not and was not cost-effective, and does not qualify for the incentive.

Q. Have you reviewed the Department of Revenue's determination that the plant was eligible for the public utility excise tax credit?

A. Yes I have. The Department concluded that coal plants were not alternatives because they were too big, ignoring partial ownership (such as that of WWP in Colstrip). They concluded gas plants were not alternatives because of the Powerplant and Industrial Fuel Use Act (PIFUA) even though Puget had long-since mastered the art of hydro-firming with gas. They failed to consider long-term purchased power arrangements such as that entered into by Black Hills Power and Light for Pacific Power and Light's share of the output from Colstrip #3, which occurred at the same time that Kettle Falls entered rate base. In my opinion, the Department decision does not reflect a good understanding of the energy market. There is another reason the Department decision should be ignored by the Commission: WWP never filed with the Commission to reduce rates to reflect the public utility excise tax credit; by keeping that credit, WWP (now Avista) has already received an "incentive award" for Kettle Falls that it never earned.

E. Bimonthly Meter Reading and Billing and Bill Inserts

Q. What issue do you take with the Company's meter reading and billing expenses?

A. There are two inter-related revenue requirement issues. First and foremost, this Company reads meters and renders bills monthly, and I believe that leads to excessive expense for the residential sector. I propose that only bimonthly meter reading and billing expense be allowed. Second, the Company has been using the billing envelope for merchandising many things unrelated to utility service, and a significant portion of the printing, postage, and processing costs should be allocated to these non-regulated operations.

Q. Why do you recommend that only bimonthly meter reading and billing be allowed?

A. Meter reading and billing take up too much of the revenue requirement. This activity costs nearly as much as maintaining the entire utility distribution system. In this proceeding, electric meter reading and billing expenses for the residential sector are $3.8 million, an amount equal to about 73% of the total distribution maintenance expenses of $5.3 million. In the gas operation, it is even more dramatic, with meter reading and billing expenses of $1.5 million compared with $2.0 million of total distribution system maintenance expense.

Q. What is the Commission's policy on meter reading and billing?

A. WAC 480-100-101 provides that utilities must read meters and render bills no less frequently than bimonthly.

Q. How do you recommend the Commission interpret this policy for this utility?

A. I recommend that the minimum required frequency be the allowed frequency for ratemaking purposes. The Company should bear the burden of proof that more frequent meter reading is cost-effective.

Q. What evidence do you have that monthly meter reading and billing is not cost-effective?

A. First, we asked the Company for any analyses it had prepared on the subject. Exhibits 30 and 31 show that they have virtually no analysis whatsoever, other than a survey of the practices of other utilities. That survey shows that other large utilities, including Seattle, Tacoma, and Snohomish PUD, all read meters and render bills bimonthly.

Second, Puget did a major "Billing Process Study" on this issue many years ago, and that study was considered in that Company's general rate case.[1] The Puget study found that there was a 90% chance that the benefits of switching from bimonthly to monthly meter reading and billing would be negative (and Puget even counted accelerated cash flow as a benefit, which it is not since that "benefit" to the Company is offset by an equal cost to consumers).

Third, a study by Portland General Electric found that bimonthly meter reading and billing could save as much as $800,000 per year once the conversion was complete.[2]

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1 Response to Public Counsel Data Request No. 1480, Docket UE-921262

2 PGE Response to Utility Reform Project Data Request #68, OPUC Docket UE-79

Q. What would be the cost savings from bimonthly meter reading and billing?

A. The savings would be nearly half of the meter reading and billing expense attributable to the residential sector; I have assumed a 45% reduction, because some reading and billing is related to move-in and move-out activities, which would remain unchanged. Therefore I have calculated that Avista would save approximately $1.7 million in electric expense, and $1.1 million in gas expense.

Q. Are there other costs to bimonthly meter reading and billing?

A. Yes, there is a slight expected increase in uncollectible expense, and there is a working capital requirement associated with an increased lag between the time that energy is consumed and the time the meters are read.

The first is a very small cost. A reasonable comparison would be between Avista's and Puget's uncollectibles experience. In the Commission's 1987 study, <u>Indicators of Collection Problems in Electric and Gas Utilities in Washington State</u>, that difference was around 0.2% of revenue. The second is a perceived cost: while the utility must carry the cost of providing service longer, the customer is on the receiving end of that lag. If the utility is made whole, by including the increased lag in a working capital allowance in rate base, and ratepayers bear that working capital expense, the net effect on both ratepayers and shareholders is zero unless there is a demonstrated difference between the utility's cost of capital and the consumer's cost of capital.

Q. Have utilities surveyed consumers to see if they prefer monthly or bimonthly meter reading and billing?

A. Yes. The results of these surveys depend on how the question is asked. I think it is best to ask the question with information on the cost or savings associated with the choice. When the

City of Olympia asked utility consumers if they would be willing to pay an additional $1.00/month for monthly meter reading and billing for (water, sewer, garbage and stormwater) utility service, 83% said NO, they would not be willing to pay that amount. At $1.75/month, the number saying NO went up to 87%. The extra costs that Avista consumers are being asked to bear in this proceeding for monthly meter reading and billing, are in this range.

Q. What elements do you think should be a part of a conversion to bimonthly meter reading and billing?

A. Customers should be encouraged to join a level-pay billing program, such as Avista's Comfort Level Billing Plan to reduce surprise bill amounts. Customers should be encouraged to join auto-pay programs that draft utility bills from bank accounts to reduce inadvertent late payment.

Q. Have you calculated the decrease in expense and increase in rate base associated with moving to bimonthly meter reading and billing?

A. Yes. Exhibit ___(JL-RR-5) shows this calculation. This includes the reduction in meter reading and billing expenses, an increase in uncollectibles, and an increase in rate base to compensate the Company for the additional lag. Mr. Damron is responsible for putting this into results of operation format.

Q. Please turn to the billing inserts which are included in Exhibit 501. Are the costs of producing and distributing these inserts appropriate for inclusion in utility rates?

A. No, they are not. These are examples of inappropriate merchandising through the billing envelope. If ratepayers are expected to pay for the costs of printing and mailing bills, then the entire content of the billing envelope should consist of public service material, not non-regulated promotional material. The Commission dealt with this issue in detail in Washington Natural Gas's rate case in Docket UG-920840. First, the Commission approved a reallocation of costs to the non-regulated operations. The Commission included a large addition to net operating income and deduction from rate base for merchandising and jobbing. The Commission ordered a $16.9 million reduction in rates in that docket, a significant part of which was due to the inclusion of non-regulated operations in the utility plant and expense accounts. Finally, in the subsequent case, the Commission approved a franchise fee to transfer revenue from the non-regulated operations to the utility.

Q. Are you proposing a similar reallocation of expenses in this proceeding?

A. No, I am proposing that only bimonthly meter reading and billing costs be allowed. Of the total number of bill inserts, less than half were for promotional or marketing purposes. If the Commission accepts the adjustment to meter reading and billing expense, the effect will be to reduce the mailing opportunity and allowed expense for bill inserts by 50% as well. With some guidance to the Company to discontinue the promotion of non-regulated operations in the billing envelope, I believe the problem can be resolved, future costs avoided, and rates set at an equitable level to recover appropriate billing costs.

F. Equity Bonus

Q. Please turn to the Company's proposal that it be granted a 0.25% bonus on the allowed return on equity as proposed by Mr. Dukich. Is this bonus justified?

A. No, it is not. Other than the low-cost hydroelectric power resulting from investments generations ago, Avista does not have lower costs than neighboring utilities, and should not receive any special treatment.

Q. Have you prepared a comparison of Avista's non-production Operations and Maintenance (O&M) expenses to those of nearby utilities?

A. Yes I have, based on information that Mr. Dukich himself presented in the Centralia proceeding, Docket UE-991255. Mr. Dukich's Exhibit 319 in that case identified nine investor-owned utilities and their non-production cost per customer. The results of his analysis are shown below, in order of decreasing cost:

Non-Production Costs Per Customer for Western State IOUs

Utility	Non-Production $/Customer	Customers/Circuit-Mile
Avista	**$342.01**	**29.76**
Idaho Power	$322.31	13.41
Pacificorp	$300.13	26.00
Tucson Electric	$288.25	20.71
Portland GE	$271.04	42.59
Sierra Pacific	$247.33	22.84
So Cal Edison	$227.18	38.48
Puget Sound Energy	$200.07	49.00
San Diego G&E	$194.02	88.83

Source: Dukich, Exhibit 319, Docket UE-991255

Of the nine utilities identified by Mr. Dukich, Avista had the HIGHEST non-production cost per customer. This is in spite of the fact that as a combination utility (gas and electric), Avista has a natural advantage in customer account services, telephone center operations, and overhead. The other combination companies, Sierra Pacific, PSE, and San Diego, constituted three of the four lowest cost utilities. Even the other rural utilities, with fewer customers per pole-mile than Avista (i.e., Idaho Power, Pacificorp, Sierra Pacific, and Tucson Electric) had significantly lower operating costs than Avista. Avista is simply an outlier in the data set – higher than any of the others.

Q. Have you examined other studies of the non-production cost per customer, and if so, how does Avista compare?

A. In the current Pacificorp docket, UE-991832, that Company provided a comparison of 72 utilities on this same basis. Out of 72 utilities in that survey, 55 had non-production costs of less than $300/customer, or significantly less than Avista. Avista (Washington Water Power) was not included in this particular study.

Q. If the Company's management does not appear to excel, why are Avista's rates so much lower than other investor-owned utilities?

A. There are two basic reasons. First, The Washington Water Power Company was worthy of its name; with more than two-thirds of total power coming from hydroelectric facilities, the Company has been less affected by high costs of thermal (coal and nuclear) generation facilities. A related fact is that the Company has had a relatively slow-growing customer base. This slow growth means that the older, low-cost generating resources can meet a much larger percentage of WWP's load than is possible for a fast-growing utility, and WWP did not have to invest in high-cost generation at the same rate as a fast growing utility might have. This slow growth also meant that WWP has not had to invest in new, high-cost underground distribution plant in the same way that fast-growing utilities like PSE have had to do. Finally, as a combination utility, it has been my observation that WWP was less willing to "chase" natural gas load than were single-service utilities like Washington Natural Gas, meaning that the electric system and the gas system could be developed at lower costs per customer.

While the investment in Noxon Rapids and Cabinet Gorge may be thought of today as visionary, the recognition for that vision is deserved by our predecessor utility managers, regulators, and consumers who recognized and paid for the potential future value of those resources a generation or more ago; the reward was not earned by today's Avista shareholders or managers.

Q. How is this adjustment addressed in the calculation of the revenue requirement?

A. My testimony demonstrates that the additional bonus to the return on common equity is not justified. Mr. Hill has not incorporated this proposed bonus into his estimated cost of equity capital. Mr. Damron then uses Mr. Hill's cost of capital in computing results of operation.

IV. POWER COST ADJUSTMENT MECHANISM

Q. Should the Company's proposed Power Cost Adjustment (PCA) be approved?

A. No, it should not. It is little changed from the proposal the Company made twelve years ago, and it should be rejected for the same reasons.

Q. What are the principal reasons to reject the proposal?

A. The proposed mechanism is largely similar to the one rejected by the Commission over a decade ago. As I detailed in my testimony in Cause U-88-2363-P, there were five major problems with the Company's proposal at that time;

1) Because the mechanism is asymmetrical, there would be more surcharges than credits;
2) The mechanism would lead to random variations in rates;
3) The mechanism would create incentives for inefficiency in managing power supply;

4) The mechanism would permit double-recovery of fixed power supply costs;

5) A uniform percentage surcharge is inappropriate.

Q. Which of these problems remain with the Company's new proposal?

A. All would still be present. The exclusion of new long-term power supply resources mitigates issue #4, but if the Company made short-term purchases to serve load growth, the same problem would return. That is precisely what happened with Puget's Energy Cost Adjustment Clause, and was one reason it was terminated.

Q. What was the Commission's decision in the previous PCA proceeding?

A. The Commission rejected the proposal, based on evidence presented by Staff and Public Counsel that the mechanism failed on two of the three key criteria it applied. The first was whether it was weather-related, and the Commission found the lag unacceptable; the second was exclusion of long-term resources, which the Commission found was acceptable; the third was a downward cost of capital adjustment, which the Commission found was lacking

Q. Does the current proposal solve these concerns?

A. No, it does not. The lag problem is just as serious if not more so; under the current proposal, a dollar balance could accrue into the balancing account at any time, and be recovered when the balance exceeds the trigger, which could be months or even years later. As a result, surcharges for drought conditions could be imposed years after the drought was over.

It is not at all clear how market purchases to serve load growth would be treated, but it appears that the Company proposal would create a double-recovery problem by setting base rates at a level that covers fixed and variable power supply costs, and then deferring into a balancing account all variations in purchases. While the Company testimony states that load growth will not be incorporated, it is not at all clear how it would be segregated.

Q. How does the current proposal address the third of the concerns addressed by the Commission, the cost of capital impact?

A. In the 1988 case, the "benchmark" used was the recently-negotiated settlement in Cause U-88-2380-T, in which a 38% equity capitalization ratio was agreed to. In the 1988 proceeding, Mr. Eliassen (the Company's financial witness) testified that eventually the Company would not need as much equity in its capital structure if the PCA was approved.[3] In this proceeding, even with the proposed PCA, the Company is requesting a much higher-cost 47% equity capitalization ratio, and even Mr. Hill is recommending a higher equity capitalization ratio than was agreed to in 1988. So the Company has not requested a decrease in the equity capitalization ratio below that agreed to in 1988. I note these relationships because of my historical perspective; Mr. Hill is the cost of capital witness for Public Counsel in this proceeding.

V. EFFECT OF CENTRALIA SALE

Q. What recommendations do you make with respect to treatment of the Centralia sale in this proceeding?

A. If and when the Centralia plant is sold and the Company files amendatory exhibits to incorporate the Centralia sale, Public Counsel will be prepared to examine those exhibits and submit direct and rebuttal testimony on that issue. At this time, it is not at all certain that the sale will proceed. There are two issues I address here, based on representations by the Company in

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[3] Docket U-88-2363-P, First Supplemental Order, P. 9

the Centralia proceeding. The first deals with replacement power costs, and the second with state income taxes.

Q. What is the issue you feel the Commission should address with respect to replacement power costs?

A. The Company's testimony in the Centralia proceeding indicated that they expected the sale of the plant to result in lower power supply costs. Specifically, Mr. Johnson's exhibit 304 and cross-examination exhibit 332 showed that replacement power would cost LESS than Centralia for the first decade following the sale; this is shown in detail in my Exhibit ___(JL-RR-6). The Company's oral testimony in this proceeding by Mr. Norwood and Mr. McKenzie indicates that replacement power will cost MORE than ownership and operation of Centralia.

Public Counsel sought to introduce this evidence into the proceeding on Centralia through a motion to reopen that proceeding, but the Commission indicated that the appropriate way to address this was through a monetary adjustment in the rate proceeding (4th Supplemental Order, P. 8).

The Commission also noted in that order that any comparison of the cost of Centralia to replacement power should include the scrubber cost. I should note that the "Total Delivered Centralia Cost" from Mr. Johnson's Exhibit 304, replicated in my Exhibit ___(JL-RR-6), does include the scrubber cost. This is evident by the sharp run-up of Centralia capital recovery costs from 4.29 mills/kwh in 1999, before the scrubber construction began, to 8.1 mills/kwh in 2004, after the scrubbers were both to be operational.

Q. What is your recommendation in this proceeding?

A. The Company should be held to its word in the Centralia proceeding, and if the sale of this plant is consummated, that sale should be accommodated by lower power costs in the short run. Any proposed upward adjustment should be rejected. Because the Company has not submitted amendatory exhibits at this point in this proceeding, The Commission should review the Centralia replacement power decision process and resulting resources in the Company's next general rate case.

Q. What is the state tax issue which carries over from the Centralia proceeding?

A. The Company in docket UE-991255 sought to include state income taxes as a "cost" associated with the sale of Centralia which would reduce the amount of gain available to Washington ratepayers. Washington does not impose a state income tax, and such an adjustment is inappropriate. The Company previously testified that Idaho agreed to assign responsibility for any Idaho tax liability to Idaho ratepayers. The issue is that there are two states (California and Oregon) in which Avista has gas operations, but does not have electric operations.

Q. If the sale generates a taxable gain, wouldn't states such as California, which tax Avista's income seek to collect additional state taxes from that gain?

A. Perhaps, and if they are successful, those state taxes constitute a windfall to those states. Gas ratepayers in those states paid <u>nothing</u> towards the cost of Centralia, will pay nothing towards the replacement power for Centralia, but for some reason the Company seems to think that they have a method to claim a share of the gain on Centralia for state tax purposes.

Q. What is the problem regarding state income taxes?

A. If Avista were a single-state utility serving Washington only, there would be no state tax liability deducted from the gain available to Washington ratepayers. For example, if instead of owning 15% of Centralia and assigning 66.99% to Washington, a separate company serving Washington owned 10% of Centralia (Puget is an example, owning 7%), there would be no such tax liability. In my opinion, ratepayers in this state should not be made worse off because of a decision by Avista to expand its gas operations into additional states.

Q. How should this Commission handle this problem?

A. First, the Commission should state that Washington ratepayers should not be adversely affected by California or Oregon income taxes, period. Similarly, California and Oregon ratepayers should not be adversely affected by Washington's Public Utility Excise Tax. Second, the Commission should insist that the states imposing income taxes on the sale of Centralia should bear any cost of those taxes. Since the benefit of this tax goes to California and Oregon, an offsetting charge should be accepted by California and Oregon. The Company should be directed to account for the sale by first dividing the gain and appreciation between Idaho and Washington using the same process as for other power supply resources, then calculating the taxes due under Washington and Federal law to the Washington portion in computing the amount of the gain which should be credited to Washington customers. No consideration should be given to out of state taxes.

Q. Have you computed the changes to the Company's proposed method needed to achieve this tax treatment?

A. No. At the time this testimony was drafted, it was not even known whether the Centralia sale would proceed. The Company has not filed any proposed exhibits dealing with the Centralia sale, and until it does, it is not possible to respond in detail. However, since the Commission has previously indicated that this proceeding would be the place to address this issue, but has set no schedule for either the Company or other parties to address the Centralia issue, it is obviously important that Public Counsel register its positions at the time provided for direct testimony, even though there is nothing on the record to respond to yet. I expect that a reasonable opportunity will be provided to respond in detail to any proposal which is made by the Company.

VI. CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your conclusions and recommendations.

A. First, I have demonstrated that a number of the Company's revenue requirement items should be revised. These include administrative and general expenses, production depreciation expense for hydroelectric plants, franchise fees for the use of the corporate name, meter reading and billing expenses, the Kettle Falls renewable resource bonus, and the proposed equity bonus.

Second, I have demonstrated that the proposed Power Cost Adjustment suffers from the same shortcomings which led to its rejection over a decade ago. I conclude that it should again be rejected.

Finally, I discuss why the Company should not be allowed to recover more revenue for Centralia replacement power than it previously testified to in the Centralia proceeding.

Q. Does this complete this portion of your testimony?

A. Yes. Separate testimony and exhibits address Public Counsel's recommendations on gas and electric rate design. In addition, I am part of a panel of three witnesses on electric rate spread, and a panel of three witnesses on gas rate spread.

Before the
Washington Utilities and Transportation Commission

Docket Nos.
UE-991606 (Electric)
UG-991607 (Gas)

Exhibits accompanying the

Direct Testimony of Jim Lazar

Consulting Economist

On Behalf of
Public Counsel

Revenue Requirement Portion

May, 2000

Exhibit ___(JL-RR-1)	Administrative and General Salaries
Exhibit ___(JL-RR-2)	Franchise Fees for Use of Corporate Name
Exhibit ___(JL-RR-3)	Production Depreciation Expense
Exhibit ___(JL-RR-4)	Kettle Falls Cost-Effectiveness
Exhibit ___(JL-RR-5)	Meter Reading and Billing
Exhibit ___(JL-RR-6)	Centralia Replacement Power Cost