Exhibit T- __ (DWS-T-Errata)
Docket No. UE-991606
Docket No. UG-991607
Witness: Donald W. Schoenbeck

T-718

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Washington Utilities and Transportation Commission,	)	
Complainant	)	**DOCKET NO. UE-991606**
vs.	)	**DOCKET NO. UG-991607**
Avista Corporation,	)	
Respondent	)	

ERRATA TO

DIRECT TESTIMONY OF
DONALD W. SCHOENBECK
ON BEHALF OF THE
INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

DATED: JULY 6, 2000

WUTC
DOCKET NO. UE-991606
EXHIBIT # T-718
ADMIT ☑ W/D ☐ REJECT ☐

Exhibit T- __ (DWS-T-Errata)
Docket No. UE-991606
Docket No. UG-991607
Witness: Donald W. Schoenbeck

Errata Sheet to the Prefiled Testimony of
Donald W. Schoenbeck
on behalf of the
Industrial Customers of Northwest Utilities

Page 5, lines 15-17
Replace the sentence beginning on line 15 with the following: I recommend reflecting all of the ratepayer's share of the Centralia gain in the proposed revenue requirement. In other words, the Company should not be allowed to offset a portion of the ratepayer gain with the 1996 Ice Storm costs.

Page 28, line 11
Insert the word "be" between "should" and "flowed"

Page 28, line 18
Change "$1.2" to "$10.2"

Page 34, line 1
Change "2001" to "2002"

Exhibit T- __ (DWS-T)
Docket No. UE-991606
Docket No. UG-991607
Witness: Donald W. Schoenbeck

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

ORIGINAL

Washington Utilities and Transportation Commission,	)	
Complainant,	)	**DOCKET NO. UE-991606**
vs.	)	**DOCKET NO. UG-991607**
Avista Corporation,	)	
Respondent	)	

DIRECT TESTIMONY OF
DONALD W. SCHOENBECK
ON BEHALF OF THE
INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

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Of Attorneys for Industrial Customers of Northwest Utilities

DATED: May 5, 2000

PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Donald W. Schoenbeck. I am a member of Regulatory & Cogeneration Services, Inc. ("RCS"), a utility rate and economic consulting firm. My business address is 900 Washington Street, Suite 1000, Vancouver, WA 98660.

Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE.

A. I've been involved in the electric and gas utility industries for over 25 years. For the majority of this time, I have provided consulting services for large industrial customers addressing regulatory and contractual matters before numerous state commissions, public utility governing boards, governmental agencies, state and federal courts, the National Energy Board of Canada and the Federal Energy Regulatory Commission ("FERC"). I have appeared before the Washington Utilities and Transportation Commission ("WUTC" or "Commission") at least 20 times since 1982. A further description of my educational background and work experience is summarized in Exhibit DWS-1.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am testifying on behalf of the Industrial Customers of Northwest Utilities ("ICNU"). ICNU is a non-profit trade association, whose members are large industrial customers served by electric utilities throughout the Pacific Northwest, including Avista Corporation (the "Company").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses certain issues related to the Company's revenue requirement for electric operations in its pending general rate case. The specific issues addressed by my testimony are:

- The erroneous portrayal of the Company's capacity sale transaction with Portland General Electric ("PGE"), including the implications for the Company's equity bonus request;
- The proposed exclusion of margins from commercial trading transactions;
- The proposed treatment of the sale of Centralia, including the disposition of the ratepayer's share of the gain from the sale;
- The proposal to establish a Power Cost Adjustment ("PCA") mechanism; and
- The attempted recovery of non-recurring expenses.

My testimony does not address numerous other matters of concern raised by the Company's filing, which should not be construed as acceptance by ICNU of the Company's proposals on those items.

Q. PLEASE BRIEFLY SUMMARIZE YOUR TESTIMONY.

A. The Company's filing proposes a $26.3 million increase in its electric utility revenue requirements for Washington. Since the initial filing, the Company has proposed to reduce its requested revenue requirement increase by about $2 million because of the Commission's decision regarding the sale of the Centralia coal plant, and by another $2.3 million as a result of a proposed settlement between the Company and Staff on depreciation expenses. As a result, the Company's proposed increase in revenue requirements is now approximately $22 million.

My testimony proposes that the requested revenue requirement be reduced even further, by the following amounts:

ICNU Proposed Adjustments1/	**($ millions)**
PGE Contract Sale	-$9.5
Equity Performance Bonus	-$1.2
Washington Regulatory Fees	-$0.5
Commercial Trading Margins	-$4.2
Centralia Adjustment	-$8.2
1991 Fire Storm	-$0.6
Name Change	-$0.2
Y2K	-$0.2
ICNU Recommendation Total:	-$24.6
Company Rate Increase/(Decrease)	-$(2.6)

If these changes are adopted, the Commission will have to lower the Company's electric rates rather than raise them. These adjustments are conservative, because they *assume* the use of the Company's proposed capital structure and its proposed 12 % return on equity. Although ICNU believes that an additional adjustment downward should be made to the Company's revenue requirement to

1/ The Centralia adjustment assumes that 1996 Ice Storm costs have also been excluded from revenue requirement. The original filing included $2.1 million for ice storm costs.

reflect a more reasonable return on equity, ICNU intends to rely on testimony of Staff and Public Counsel to address this issue. A description of each proposed ICNU adjustment is summarized below.

1. <u>PGE Contract</u>

The Company has failed to notify this Commission in its direct testimony or by other means that in 1998 it assigned its rights under a long-term capacity sale agreement to a related entity and received a lump sum payment of $141.8 million. I recommend that this payment be flowed through to ratepayers over an eight-year period. The contractual arrangements in effect today – rather than the Company's erroneous use of outdated numbers – should be used in deriving the Company's revenue requirement. A simple calculation indicates these recommendations would lower the Company's revenue requirement by $9.5 million.

For concealing this payment from the Commission, I recommend that the Commission deny the Company's request for a 25-basis point common equity bonus, which results in a $1.2 million reduction in the proposed revenue requirement. Furthermore, the Commission should disallow the recovery of regulatory fees in Washington as a penalty for failing to disclose this transaction and to provide a clear signal that the Commission will not tolerate this type of behavior. This adjustment reduces the proposed revenue requirement by $500,000.

2. Commercial Trading

The Company has been — and continues to be — a very active participant in the wholesale bulk power market; however, it is proposing to ignore the vast majority of this activity in deriving its revenue requirements. Based upon the documents maintained by the Company, I recommend including in the pro forma revenue requirement the margins realized during the 1998 test period from commercial transactions executed by the regulated utility. This amount reduces the Company's Washington revenue requirement by $4.2 million.

3. Centralia

If the Centralia facility is sold, the Company proposes to offset a portion of the ratepayer gain from the sale with the unrelated cost of repairs performed as a result of the 1996 Ice Storm. The Company also proposes to replace the energy provided from the facility with a "take-or-pay" contractual commitment that extends until December 31, 2003. I recommend excluding the 1996 Ice Storm costs and flowing all of the ratepayer's share of the Centralia gain from the proposed revenue requirement. To replace the power produced by Centralia, I recommend using market purchases for ratemaking purposes until the Commission can conduct a thorough reasonableness review of the proposed replacement contract. Although the Company itself has proposed to reduce its initial rate request by about $2 million to comply with the Commission's

Centralia order, my recommendations go further and reduce the request by an additional \$8.2 million, or \$10.2 million from the Company's original filing.

4. <u>Non-Recurring Costs</u>

The Company's proposed revenue requirement includes many cost items that were either extraordinary and/or which are not likely to occur again in the foreseeable future. According to standard ratemaking principles, these costs should not be included in deriving the normalized revenue requirement. These costs include: changing the name of the utility; the 1991 Fire Storm; the 1996 Ice Storm; and Y2K preparedness expenses. Eliminating these cost items from the Company's original filing reduces the revenue requirement by an additional \$4.2 million. To the extent the ice storm amount was previously removed as part of the Company's Centralia proposal, the reduction associated with the other items is \$1.0 million.

5. <u>Power Cost Adjustment</u>

The Company is seeking approval of a Power Cost Adjustment ("PCA") mechanism, which is similar to one rejected by this Commission in 1989. The Company's proposal does not satisfy the standards set forth in the Commission's 1989 decision, nor does it comport with the Commission's long-standing policies regarding PCA's. Furthermore, in today's regulatory environment, mechanisms like PCA's are being replaced around the country with more competitive and innovative, performance-based regulation. This change is occurring because traditional PCA's do not provide an incentive for utilities to be efficient. For those reasons, I recommend that the Commission reject the Company's proposed PCA.

THE PGE POWER SUPPLY TRANSACTION

Q. HAS THE COMPANY MISCHARACTERIZED ITS POWER SALE TRANSACTION WITH PGE? IF SO, PLEASE DESCRIBE.

A. Yes. In 1992, the Company entered into a long-term contract to sell capacity to PGE. The contract is denoted as "PGE #1 Capacity" on line 89, page 3 of 4, of Exhibit No. 152. This abbreviated title refers to the "Agreement for Long Term Purchase and Sale of Firm Capacity," dated June 26, 1992, between PGE and The Washington Water Power Company ("WWP") ("Agreement"). The Agreement called for WWP to sell 50 megawatts (MW) of capacity to PGE from November 1992, through October 1994, and to sell 150 MW from November 1994, until the contract terminated on December 31, 2016. The Agreement contained a stream of capacity rates for each year under the Agreement. As set forth in column (b) of Exhibit No. 152, the Company received $18.72 million in 1998 under the Agreement. According to column (d) of this exhibit, the Company expects pro forma revenues of $18 million under the Agreement, between June 30, 2000, and June 30, 2001.

Q. WHAT IS THE COMPANY'S REASONING FOR MAKING A PRO FORMA ADJUSTMENT TO A POWER SALES CONTRACT?

A. The Company insists that it makes adjustments to the pro forma period to reflect changes from historic "test year" data. The Company addresses this issue in Exhibit T-151, page 5, lines 18-23:

> ...[A]djustments are made to reflect known and measurable changes between the 1998 test period and the time period that retail rates would be in effect (the pro forma period). For example, power contracts that terminate at the end of the 1998 test period will not be in place when a Commission order is issued in this case and new rates are implemented. Therefore, adjustments are made for known and measurable power supply revenues and expenses so that the proper costs are reflected in customers' rates at the time they are implemented.

Q. HAS THE COMPANY ACCURATELY DEPICTED THE AGREEMENT WITH ITS PRO FORMA ADJUSTMENT?

A. No. The Company's representation of pro forma revenues under the Agreement is inaccurate. There will be no revenue from the Agreement because the Company's rights and obligations were sold on December 31, 1998, for a cash payment of $141.84 million. Furthermore, the Company executed new contracts as part of an arrangement with Enron Power Marketing, Inc. ("EPMI") and a related WWP entity, Spokane Energy L.L.C. EPMI is a subsidiary of Enron Corp. Under these contracts, the Company sells capacity to EPMI, which in turn sells it to Spokane LLC, which in turn sells it to PGE. Indeed, the pro forma calculation and the power supply workpapers supplied by the Company in this proceeding are misleading because they create the impression that the capacity rate schedule contained in the initial Agreement is still in effect. Based upon this misinformation, one would conclude that the Agreement between the Company and PGE remained in force for the pro forma period. That is not the case.

Q. PLEASE PROVIDE A BRIEF HISTORY OF THE KEY EVENTS THAT LED TO THE SALE OF THE CONTRACT.

A. From the documents provided in response to data requests, it appears the Company — in coordination with Enron Capital Trade and Resources Corporation ("ECT") — suggested to PGE in 1997 that it "buy down" the Agreement to a rate closer to the current market value of capacity. At the time, Enron Corp. – the parent of ECT – had recently purchased PGE. The arrangement would benefit the Company because it would realize a substantial amount of cash, and would reduce the risk that PGE would default on the contract because the existing rate substantially exceeded the market value of capacity. By mid-1998, it appears that the Company, ECT and PGE agreed to monetize the revenue stream under the Agreement. Washington Water Power then created a limited liability corporation, Spokane Energy LLC, in which WWP would indirectly hold all of the assets. There are numerous complex documents related to this transaction. Based on a review of records submitted in response to data requests, it is possible to identify the basic milestones:

1) WWP and PGE modified the Agreement to allow for its assignment without the consent of the other contracting party. PGE accepted this Amendment to the Agreement on September 4, 1998;

2) The Federal Energy Regulatory Commission ("FERC") approved the Amendment;

3) Spokane Energy LLC received FERC approval on October 16, 1998, to sell power at market-based power tariffs;

4) Spokane Energy LLC signed a power purchase agreement with Enron Power Marketing, Inc. on October 1, 1998 ("EPMI Purchase Agreement");

5) WWP signed an agreement, dated October 1, 1998 ("EPMI Long-Term Services Agreement"), to sell capacity to EPMI.

6) WWP signed an agreement with Spokane Energy LLC for the administration of the new power supply transactions dated December 1, 1998 ("Service Agreement");

7) WWP assigned the Agreement to Spokane Energy LLC on December 31, 1998, and in exchange, received a lump sum payment of $141.84 million from Spokane Energy LLC on December 31, 1998;

As of December 31, 1998, the Company was relieved of both its right to receive payment and its obligation to provide capacity directly to PGE under the Agreement. In exchange, the Company received almost $142 million. To put this amount of money in perspective, the Washington ratepayers share of the pre-tax gain from the Centralia sale is approximately <u>$31 million</u>. The Company's payment from Spokane Energy LLC was more than four times that amount.

Q. DID THE COMPANY INFORM THE COMMISSION OR THE COMMISISON STAFF ABOUT THIS TRANSACTION?

A. From the documents provided in response to data requests, it appears that the Company did not inform the Commission. Although some discovery documents refer or note the possibility of alerting the Commission, no document indicates that such a briefing actually occurred. The Company's pre-filed direct testimony in this proceeding does not mention one word about these transactions.

Q. WHAT WAS THE PURPOSE OF THE AGREEMENTS EXECUTED BETWEEN SPOKANE ENERGY LLC, EPMI AND THE COMPANY?

A. Under the EPMI Purchase Agreement, Spokane Energy LLC buys 150 MW of capacity from EPMI to perform its obligations under the assigned Agreement to PGE. Under the EPMI Long-Term Services Agreement, the Company provides 150 MW of capacity to EPMI, which apparently supports EPMI's contractual obligation to Spokane Energy LLC.

Q. WHAT IS THE CHARGE FOR THE CAPACITY SOLD BY THE COMPANY TO EPMI UNDER THE LONG TERM SERVICES AGREEMENT?

A. The Company's contract under the EPMI Long-Term Services Agreement calls for EPMI to pay the Company a rate of $1,000 per megawatt-month, less an allowance for certain administrative costs. EPMI, however, pays these administrative costs to Spokane Energy LLC, which in turn pays the amount to the Company, pursuant to the Service Agreement. Thus, these contractual arrangements result in a total revenue flow to the Company of $1.8 million per year.

Q. HOW SHOULD THE COMMISSION TREAT THESE TRANSACTIONS FOR RATEMAKING PURPOSES IN THIS PROCEEDING?

A. First, the revenues from the Long-Term Service Agreement that is in place between the Company and EPMI should be used to replace the amount indicated in Exhibit No. 152 for the pro forma period. The pro forma revenues of $18 million listed in Exhibit No. 152 should, in fact, be zero because the Company no longer has any obligation under the initial Agreement during the pro forma period. Another line should be inserted in this exhibit to reflect income from the EPMI Long-Term Services Agreement. This line should reflect zero revenues for the historical 1998 test period and $1.8 million for the pro forma period. Second, the $141.8 million payment received by the Company from Spokane Energy LLC in December 1998 — along with interest for eighteen months (roughly $20.9 million for a total of $162.7 million) — should be flowed through to customers over the same amortization period as the Centralia gain. Finally, the unamortized portion of the payment should be reflected as a credit to the Company's rate base.

Q. WHAT EFFECT WOULD THIS RECOMMENDATION HAVE ON THE COMPANY'S REQUESTED ELECTRIC REVENUE REQUIREMENT?

A. My recommendation would have the effect of reducing the Company's requested revenue requirement by $9.5 million per year. I quantified the effect of my recommendation by relying in part on the Company's proposed eight year-amortization period for the gain from the sale of Centralia, and the Company's proposed 9.9% cost of capital (return on rate base). Using a simple mortgage payment calculation, the levelized ratepayer credit from the Spokane Energy LLC payment would be $30.4 million per year. When coupled with the $1.8 million revenue stream from the EPMI Long-Term Services Agreement, the system credit is $32.2 million, compared to the $18 million value shown in Exhibit No. 152 for the Agreement. Thus, for the Washington jurisdiction, my recommendation reduces the Company's claimed request by about $9.5 million (($32.2-18.0) x 66.99% = $9.5 million). The 66.99% reflects Washington's share of these revenues.

Q. WHY ARE YOU RECOMMENDING THAT ALL OF THE SPOKANE ENERGY PAYMENT BE FLOWED THROUGH TO RATEPAYERS OVER EIGHT YEARS?

A. I make this recommendation for two reasons. First, this approach is the standard rate making treatment for sales revenue. Sales revenue has always flowed through to customers because the customers pay all of the costs of the facilities from which the sales are generated. The only real question is the amortization period over which the payments should be credited to ratepayers. I recommend that the Commission adopt the same amortization period used in crediting the ratepayer gain from the Centralia sale.

Second, the Company's actions regarding this transaction are both inappropriate and misleading. The Company has characterized the initial Agreement as still being effective for the period of July 2000 through June 2001, even though the Agreement was sold in 1998 for $141.8 million. I believe the Company should have come forward to this Commission to explain the transaction, perhaps when it was being considered, but certainly no later than after the Company had completed the transaction. In addition, the Company was obligated to fully and accurately disclose these contractual relationships in this rate case and to provide an explanation and support for the proposed ratemaking treatment for the Spokane Energy payment. The Company's failure to mention this complex transaction in its filing or in the workpapers supporting the filing is inexcusable. This Commission should send a stern and strong message that the Company's behavior with regard to this transaction will not be tolerated.

Q. HOW CAN THE COMMISSION SEND SUCH A MESSAGE?

A. I recommend the Commission take two actions. First, the Commission should reject the Company's request for an additional upward adjustment of 25 basis points on the authorized return on common equity. The Company proposed this adjustment to capture the difference between a "well managed and an adequately managed utility" (Exhibit T046, at 2, lines 16-17). The Idaho Public Utilities Commission noted when it rejected the same proposed adjustment that the minimum standard of management competence must include regulatory compliance (Case No. WWP-E-98-11, Order No. 28097, pages 23-24) ("Idaho Order"). In my view, the Company's filing regarding the Agreement reflects either gross incompetence or a direct effort to mislead this Commission. In either case, it is sufficient grounds not to reward the Company's management through an equity bonus. Indeed, I recommend that the Commission impose a penalty on the Company for its failure to disclose the substantial payment it received from the assignment of the Agreement.

Q. WHAT IS YOUR RECOMMENDED PENALTY IN THIS REGARD?

A. In the Company's testimony addressing its request for an equity bonus, it notes that an equity penalty could be imposed when appropriate. Although an equity penalty is one approach, I believe a more effective penalty in this instance is to disallow the recovery of any Washington regulatory expense fees in this proceeding. In other words, the Commission's penalty would be the exclusion of the Company's claimed $489,225 in regulatory expense fees in Washington. Adoption of this recommendation will show that this Commission demands full and honest disclosure in all rate case filings. For comparison purposes, the Company's proposed 25-basis point bonus adjustment increased the revenue requirement by about $1.2 million. Therefore, my recommendation is equivalent to an equity *penalty* of 10 basis points.

MARGINS FROM COMMERCIAL TRADING TRANSACTIONS

Q. IS AVISTA UTILITIES AN ACTIVE PARTICIPANT IN THE WHOLESALE POWER MARKET?

A. Yes, very much so. The regulated utility – as opposed to Avista Energy, which is an unregulated subsidiary – is a very active participant in the wholesale bulk power markets. As noted in Exhibit T-151, the Company's short-term purchases totaled 1,746 aMW for the 1998 test period, and short-term sales were 1,774 aMW for the same period. These purchases are significantly more than the Company's entire retail load; however, this "snapshot" does not tell the complete story. The table below compares the Company's net system load with its short-term purchases and short-term sales in wholesale markets during the last five years.

Load Level Comparison
Net System Load, Short-term Purchases and Sales
(aMW)

Year	Net System Load	Short-term Purchases	Short-term Sales
1995	924	279	223
1996	973	916	840
1997	971	1,388	1,382
1998	1,096	1,746	1,774
1999	1,066	1,637	1,648

It is important to note the increases in amounts of short-term purchases and sales since 1995, compared with the modest increases in net system load.

Q. WHAT IS THE MARKET VALUE OF THESE TRANSACTIONS?

A. The market value of these transactions is shown in the following table. The dollar value of these transactions has increased substantially in a relatively short period of time.

Expense and Revenue Comparison
Short-term Purchases and Sales
($ Millions)

Year	ST Purchase Expense	ST Sales Revenue	Total
1995	$29.4	$25.0	$44.4
1996	102.5	103.3	205.8
1997	188.7	191.2	379.9
1998	356.5	354.0	710.4
1999	397.0	387.2	784.2

In summary, the Company's short-term transactions have become a very significant part of its operations, as measured either by energy volumes or by dollar amount.

Q. HOW IS THE COMPANY PROPOSING TO TREAT POWER PURCHASE AND SALES TRANSACTIONS IN THIS PROCEEDING?

A. The Company proposes to include long-term purchases and sales in deriving its revenue requirement. The Company also proposes to include short-term transactions (less than 1 year), if purchases were incurred to serve retail customers, and if the sales were provided by Company resources. The Company's proposal deems all other short-term purchase and sale transactions to be "commercial trading transactions." The Company is proposing that the net benefit (or cost) of these commercial transactions flow through to the Company's shareholders. Nonetheless, the Company proposes only a modest adjustment to the test period expense levels for the Company's Resource Optimization Department ("ROD") to recognize the payroll and overhead expense associated with 16 employees (equivalent to 4.1 full time personnel) who are involved with this commercial trading activity. For Washington, this ROD adjustment reduces test period expenses by only $305,880.

Q. HOW DID THE COMPANY ASSIGN THE TEST PERIOD SHORT-TERM TRANSACTIONS BETWEEN RATEPAYERS AND THE SHAREHOLDERS?

A. The Company made no attempt to assign the historical test period short-term energy transactions between shareholders and ratepayers in deriving its net power supply revenue requirement. The Company's testimony does indicate, however, that the vast majority of the short-term purchase and sales transactions shown in the above table for 1998 were probably commercial trading transactions. Exhibit T-151, at 20, lines 15-21. The Company has also acknowledged that it still does not have the necessary information system in place to track or differentiate commercial trading transactions from system purchases or sales that support retail operations.

Q. HOW DID THE COMPANY DERIVE THE PRO FORMA POWER SUPPLY EXPENSES?

A. The Company determined the pro forma (e.g., normalized) net power supply revenue requirement based upon serving the native system load with no regard to other market opportunities. In other words, even though the Company has been extremely active in commercial trading for the last several years, it has made no attempt to quantify the likely profit or loss from this activity for the pro forma results of operations.

Q. DO YOU AGREE WITH THE COMPANY'S CHARACTERIZATION THAT COMMERCIAL TRADING ACTIVITY IS TOO RISKY AND TOO SPECULATIVE TO BE KNOWN AND MEASURABLE FOR RATEMAKING PURPOSES?

A. No. For many years, utilities in the Pacific Northwest, including the Company, have accepted a certain level of speculative short-term sales revenue, based upon assumptions that rain will fall and snow will melt in a future year at an assumed market price. This assessment is based upon professional judgment and experience. This same judgment and experience can be used to estimate commercial trading transactions. It is obvious the Company believes commercial trading is a profitable endeavor, or it would not engage in $350 to $400 million per year of such transactions.

I agree that some commercial trading transactions can be more risky than the sale of surplus hydro generation. For example, a trader could continually sell short in anticipation that market prices will drop. When it becomes necessary to cover the sale, a market price increase would create a loss on this one transaction. Selling surplus hydro does not have the same risk because it basically has a zero incremental cost of generation, and all the fixed costs have been included in establishing the utility's retail revenue requirement. Thus, the only "risk" becomes maximizing the profits from the sale. However, a profitable and risk free commercial trading transaction also occurs when a Company scheduler or trader is aware of a seller and a buyer with strike prices that allow for a positive profit margin through a simultaneous buy/sell arrangement.

There has been an active wholesale market in the Pacific Northwest for a long time. Utility system operators or schedulers have interacted on a daily basis in order to purchase short-term power to fill a deficit or sell a short-term surplus. It is only logical for a utility, such as the Company, to use this unique market knowledge and experience to take the next step and begin conducting commercial trading transactions. The risk in taking this step is also lessened because it is precisely the same Company department — the ROD — that is procuring and selling system resources on behalf of retail customers and is simultaneously conducting the commercial trading business.

It is appropriate for ratepayers to benefit from these transactions because they have funded development of the assets and personnel necessary to conduct commercial trading.

Q. HAS THE COMPANY PROVIDED DOCUMENTS DESCRIBING ITS COMMERCIAL TRADING ACTIVITY?

A. Yes. In response to WUTC Staff Data Request 314, the Company provided records that its traders maintained for the 1998 test period for the Mid-Columbia ("Mid-C") market hub and the California-Oregon Border ("COB") market hub. The Company has provided several caveats regarding these documents, stating that the documents are not official records of the Company, that some transactions may not have been recorded, and that the documents have not been audited.

Q. WHAT HAS YOUR REVIEW OF THESE DOCUMENTS REVEALED?

A. Some transactions have resulted in sizable losses while others have resulted in sizable gains. For the test period, however, the transactions listed by the traders resulted in a total net profit margin of $6.9 million for the Company.

Q. HOW SHOULD THE COMMISSION TREAT COMMERCIAL TRADING ACTIVITY FOR RATEMAKING PURPOSES?

A. The Commission should determine an appropriate value for this activity, and include it in the Company's revenue requirement. Under this approach, and using standard rate making concepts, the imputed value should reflect the actual test period results, unless the Company can justify a more appropriate pro forma amount. The Company has made no such showing in its pre-filed testimony. Instead, it simply eliminated the activity from its pro forma analysis. I recommend using the $6.9 million recorded by the Company's traders for 1998. This is a system value and the appropriate adjustment for Washington would be a credit of $4.2 million.

Q. IS THE COMPANY'S RECOMMENDATION TO CREDIT A PORTION OF THE "ROD" EXPENSES ADEQUATE?

A. No. The Company's proposed adjustment is based upon reducing the operating expenses by the payroll and direct overhead costs of only 4.1 full time equivalent employees, even though about 16 employees within the ROD are engaged in this activity. The Company's calculation is too low, because it does not assign a value to the "intellectual property" of this department and the knowledge that Company employees have acquired from participating in the Pacific Northwest wholesale market for years. Although it is hard to place a precise value on this substantial intangible asset, acquired at ratepayer expense, I believe it is substantially above the insignificant $305,880 credit which the Company has proposed.

Q. IF THE COMMISISON REJECTS YOUR RECOMMENDATION AND ADOPTS THE COMPANY'S PROPOSAL TO EXCLUDE COMMERCIAL TRADING TRANSACTIONS, WOULD ANOTHER ADJUSTMENT TO THE COMPANY'S REVENUE REQUIREMENT BE NECESSARY?

A. Yes. All wholesale transactions conducted by the Company, including commercial trading transactions, are subject to a FERC fee. In the Company's filing, the pro forma FERC expense included commercial trading transactions. Consequently, if the Commission adopts the Company's proposal, these FERC charges must be removed. Otherwise, the ratepayers would pay the FERC fees for transactions that only benefit shareholders. The Company has estimated this adjustment at $279,280 in response to Record Request Number 14.

CENTRALIA RATE MAKING PROPOSAL

Q. PLEASE STATE YOUR UNDERSTANDING OF THE COMPANY'S RATEMAKING PROPOSALS RELATED TO THE SALE OF CENTRALIA, INCLUDING THE DISPOSITION OF THE RATEPAYERS' SHARE OF THE GAIN.

A. As presented in the supplemental oral testimony of Mr. Ron McKenzie, the Company's proposal is as follows: The first step calls for offsetting the Washington allocated share of the 1996 Ice Storm costs with the ratepayers' share of the gain from the sale of Centralia. The after-tax gain from Centralia assigned to Washington ratepayers is about $19 million. The entire ice storm amount the Company is seeking to recover over a six-year amortization period is roughly $8 million after tax. As a result, under the Company's proposal, the ice storm costs would be offset with a portion of the gain, leaving about $11 million for further disposition. As part of this step, the Company also proposed to "back out" the ice storm amortization amount from the proposed revenue requirement. This would reduce proposed operating expenses by about $2.1 million.

Next, the Company is proposing to amortize the remaining gain to ratepayers over eight years, including crediting the unamortized portion of the gain as a reduction to rate base. This step would result in a revenue credit of about $4 million. Thus, at this point, the proposed disposition of the gain would lower the Company's revenue requirement by about $6.1 million, compared to the original filing. In the final rate making step, it is necessary to remove the Centralia facility from the Company's rate base along with the associated operating expenses and include the costs associated with a replacement resource in order to supply the energy provided by Centralia. This final step results in a revenue requirement increase of $4.1 million. WUTC v. Avista Corp., UE-991606, Transcript of Hearing, March 27-31, 2000 ("Tr.") at 229, line 10. (Norwood Cross); *see also* Exhibit C-194. When taken together, all of the Company's proposed Centralia-related adjustments reduce the revenue requirement by about $2 million, compared to the Company's original filing in this docket.

Q. DO YOU ACCEPT THE COMPANY'S PROPOSED TRANSACTIONS FOR THE SALE OF CENTRALIA?

A. No. I have two objections to the Company's proposal. First, I object to the use of a portion of the ratepayer gain to offset the costs related to the 1996 Ice Storm.

As I will address later in this testimony, the Company should not be allowed to recover the costs related to this extraordinary event. The ratepayers should receive their entire share of the gain over a reasonable period of time. Using the eight year-period proposed by the Company, the Commission should credit rates by about $6.9 million per year to account for the gain, as compared to the Company's $4 million amount.

Second, I object to the replacement resource proposed by the Company in Exhibit C-194 because the Company has failed to demonstrate that it is a prudent source of power to replace Centralia. Centralia has a high availability factor throughout the year. Furthermore, the Company can displace Centralia if market prices are less than incremental generating costs (i.e., during period of high hydro production). The replacement resource, however, involves a commitment for the flat delivery or purchase of power for nine months of the year. For the remaining three months — April, May and June — the Company assumes it will buy additional energy to replace Centralia. The only time the Company can decline deliveries from the replacement resource provider is during low load periods of "significant unplanned reduction in area load." Thus, the resource cannot be economically displaced. This approach results in higher power supply costs being incurred by the Company during favorable market conditions.

Q. CAN YOU ILLUSTRATE THIS DIFFERENCE IN OPERATING FLEXIBILITY?

A. Yes. This flexibility can be shown using the results from the Company's own pro forma power supply modeling data. In the following table, Centralia's monthly available energy — excluding economic displacement — is shown in the first column entitled "Centralia Availability." The average energy produced by Centralia after economic displacement is shown in the column entitled "Centralia Expected." The economic displacement is based on the Company's power cost model using 60 water years. The difference between these two values — shown in the "Centralia Displacement" column — is the average monthly displacement over the 60 water years used in the analysis.

It is important to note that the Company's pro forma power supply analysis has an incremental cost of 15.3 mills per kilowatt hour (kWh) for Centralia displacement purposes. In other words, the plant would only be displaced — not run — if the market price was less than 15.3 mills per kWh. Note that in all months, even at this low cost, there is some economic displacement since the expected value of Centralia generation is less than the available limit. There is substantial economic displacement of Centralia in seven of the twelve months. Another important highlight from the table is that even during the spring months (April, May and June), it is not economical to displace Centralia all of the time. Even though the Company has substantial amounts of economic surplus power during these months to displace Centralia, there are still several years from historical records when it is economic to operate the facility. However, the contractual commitment the Company has made does not allow for this operational flexibility. For nine months of the year, the Company must purchase 190 average megawatts ("aMW") of power, regardless of the market price.

Energy Comparison – 60 Water years
(aMW)

Month	Centralia Availability	Centralia Expected	Centralia Displacement	Replacement Resource
July	185	127	58	190
Aug	185	175	10	190
Sept	185	171	14	190
Oct	185	171	14	190
Nov	185	176	9	190
Dec	185	145	40	190
Jan	185	162	23	190
Feb	185	123	62	190
Mar	185	141	44	190
Apr	185	99	86	0
May	134	88	46	0
June	142	95	47	0
Total	177	140	37	143

Q. CAN YOU APPROXIMATE THE VALUE OF BEING ABLE TO ECONOMICALLY DISPLACE THE REPLACEMENT PURCHASE?

A. Yes. I ran the Company's power supply model under two scenarios using all 60 water years. The first scenario included the replacement resource as a firm contractual commitment at 190 aMW for nine months while removing Centralia from the displaceable resource stack. For the second scenario, I replaced Centralia with other resources (200 aMW with 95% availability for nine months) having a displacement cost equal to the contractual price. Allowing the replacement resource to be displaced lowered the power supply cost by $9.9 million because the resource was utilized to supply just 42 aMW, compared to the contractual commitment of 143 aMW. In other words, it was more economical to buy short-term purchases on the open market to supply 101 aMW in this "displacement" scenario than to call upon the replacement resource proposed by the Company.

Q. DO YOU HAVE A RECOMMENDATION TO THE COMMISSION REGARDING THE PROPOSED REPLACEMENT RESOURCE?

A. Yes. The Company has provided little data or analysis to demonstrate the prudence of its decision to enter into a four-year, take-or-pay obligation to replace Centralia. The Commission should direct the Company to provide additional evidence to justify the reasonableness of this resource acquisition and to allow sufficient time for all parties to examine and respond to the evidence. As part of this review, the Company should address the operational restrictions and/or flexibility resulting from this resource acquisition, compared to other firm power supply alternatives which may have provided greater operating flexibility. Until this resource evaluation process has occurred and the Commission has determined that the transaction is the least cost alternative for replacing Centralia, the Commission should withhold approval of the costs associated with the replacement resource. In the interim, I recommend setting rates in this proceeding using twelve months of market purchases based on the Company's power supply model. Under the Company's proposal to replace Centralia with the TransAlta contract, the Company's revenue requirement would increase by $4.1 million. Tr. 15 229, line 10. Substituting market purchases for the Company's proposed replacement resource lowers Washington's share of power supply expenses by $5.3 million compared to the value contained in Exhibit C-194.

Q. PLEASE SUMMARIZE YOUR RATEMAKING RECOMMENDATIONS RELATING TO THE CENTRALIA SALE AND THE ICE STORM.

A. The costs related to the 1996 Ice Storm should not be used to reduce the assigned ratepayer gain from the sale of Centralia. I believe that all of the ratepayers' share of the gain should flowed through to ratepayers. Under this recommendation, the ratepayer credit arising from the Centralia sale is about $6.9 million, using an eight-year amortization period. In addition, the Commission should conduct a reasonableness review of the resource acquisition proposed by the company to replace the generation lost from the sale of Centralia. Until this has occurred, the Commission should reduce the purchase power costs shown in Exhibit C-194 by $5.3 million. Making this change would reduce the revenue requirement in the original filing by approximately $1.2 million.

The Company's proposed ratemaking transactions related to the Centralia sale would lower the initial revenue requirement filed in this proceeding by about $2 million. My recommendations reduce the proposed revenue requirement by an additional $8.2 million. My $10.2 million reduction to the original revenue requirements is based on the sum of the following components: 1) $6.9 million for ratepayers' share of the Centralia gain; 2) $2.1 million for removal of 1996 Ice Storm costs, and 3) $1.2 million from replacing Centralia with market purchases.

POWER COST ADJUSTMENT ("PCA") MECHANISM

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED PCA MECHANISM.

A. The Company's proposed PCA mechanism is designed to recover all of the costs that the Company claims are beyond its control. The Company believes these costs fall into three categories: 1) changes in generation of electricity from hydroelectric facilities because of weather; 2) fluctuations in short-term power market prices; and 3) expenses incurred from contracts signed pursuant to the Public Utility Regulatory Policies Act ("PURPA") of 1978. The Company proposes to establish a baseline or normalized amount for each of these categories and to then defer the monthly costs that deviate from this baseline amount. If the amount of the deviations reaches $6 million, the Company would then surcharge or credit all of its ratepayers to either recover or rebate the amount in question.

Q. HAS THIS COMMISSION ESTABLISHED PRINCIPLES FOR CONSIDERING AND EVALUATING SUCH MECHANISMS?

A. Yes. The Commission first considered a PCA-type mechanisms in 1982, when it approved an Energy Cost Adjustment Clause ("ECAC") for Puget Sound Power & Light Company (now known as Puget Sound Energy) ("Puget"). Since that time, however, the Commission has expressed reservations about PCA-type mechanisms. In 1989, for example, it denied WWP's request to establish a PCA.

WUTC v. Washington Water Power Company, WUTC Docket No. U-88-2363-P, First Supplemental Order (September 1989). It ended Puget's approved ECAC mechanism in 1990 after eight years. WUTC v. Puget Sound Power & Light Company, WUTC Docket No. U-89-2688-T, Third Supplemental Order (January 1990). Although the Commission adopted a modified mechanism for Puget in 1991, this mechanism too was terminated in 1995. WUTC v. Puget Sound Power & Light Company, WUTC Docket No. UE-950618, Third Supplemental Order (September 1995). During this period, the Commission has been clear it that it will only approve a PCA-type mechanism *only* if it satisfies three conditions. These conditions are: 1) the mechanism must only track costs incurred as a result of weather-related conditions; 2) the ratepayers must benefit from a cost-of-capital adjustment; and 3) the mechanism should exclude the cost of long-term resource acquisitions. The Commission has also indicated that PCAs must be easy to administer and easy for ratepayers to understand.

Q. DOES THE COMPANY'S PROPOSAL IN THIS PROCEEDING SATISFY THESE PRINCIPLES?

A. No. The Company's proposal fails all of these principles. First, the Company's proposed PCA is not a mechanism that only tracks costs incurred as a result of weather-related conditions. It includes costs related to short-term power transactions and, in the case of the PURPA contracts, includes the cost of long-term resource acquisitions. In addition, the administration of this mechanism would be very difficult and controversial to implement, and it would be hard, if not impossible, for ratepayers to understand why their rates were rising or falling at any given month. Most important of all, the Company has not proposed any adjustments to its cost of capital to reflect the lower risk of a PCA.

Q. WHY WOULD THE ADMINISTRATION OF THE PROPOSED PCA BE DIFFICULT OR CONTROVERSIAL?

A. The Company proposes to exclude commercial trading transactions from the PCA if they are unrelated to serving retail load. The Company insists in its direct testimony that commercial transactions made on the wholesale market – and unrelated to the operation of the regulated utility – will not affect rates. Shareholders will supposedly bear the benefits and risks of those transactions. But the Company by its own admission does not have a tracking system in place to tell which short-term transactions are needed to support retail operations and which ones are speculative. Company Response to ICNU Data Requests No. 9 and 30. Furthermore, the same department – and the same individuals within the Company – are conducting these transactions. As a result, there is an opportunity to "game" the system by shifting transactions that lose money to ratepayers and letting the shareholders get the benefit of transactions that make money. Without an established tracking system that allows the Company and the Commission to audit these transactions, it will be difficult if not impossible to determine after the fact whether the Company properly administered the PCA according to the Commission's requirements. As a result, I believe the PCA, as proposed by the Company, will be both difficult to administer and very controversial.

Q. DOES THE PROPOSAL INCLUDE LONG-TERM CONTRACTS?

A. Yes. The Company is proposing to track the deviation in costs of its PURPA contracts. Changes in the cost of these resources are not weather related, and the costs are spelled out in previously-agreed upon contract terms. As such, these contracts are no different than the Company's other long-term contracts, which are excluded from the mechanism. In addition, it is inappropriate to allow the Company to recover increases in this segment of purchase power agreements while not also offsetting decreases in purchase power expenses from other long-term contracts. In other words, the Company's proposed PCA appears to shift the risks of expensive PURPA contracts to ratepayers, but without a corresponding benefit in savings from other purchased power agreements.

Q. DOES THE COMPANY'S FILING PROVIDE A COST OF CAPITAL ADJUSTMENT TO ACCOUNT FOR ITS REDUCED RISK IF A PCA IS ESTABLISHED?

A. No. This omission is critical because the Commission has repeatedly stated in various orders on PCAs and related mechanisms that a company proposing such a mechanism must reduce its cost of capital. When the Commission denied Washington Water Power's proposed PCA in 1989, for example, it said that a PCA mechanism shifts risks from shareholders to ratepayers, and the ratepayers must therefore receive a tangible benefit. If the Company simply shifts risks from shareholders to ratepayers without reducing its cost of capital, as it did in 1989 and as it has done here, then there is no benefit for the Company's ratepayers.

Q. DO YOU AGREE WITH THE COMPANY'S CONTENTION THAT ITS COST OF EQUITY ANALYSIS WAS BASED ON COMPANIES WITH COMPARABLE PCAS?

A: No. During cross examination, Company witness Avera said that his selection of companies for the cost of equity analysis was based in part on the existence of a PCA or similar mechanism at these utilities. Tr. At 842-843 (Avera Cross). Because the Company's proposed cost of capital reflected the risks inherent in a PCA, it would be inappropriate for the Commission to further reduce the Company's cost of capital in this proceeding. The Company has attempted to show its a response to Record Request No. 26 ("Response") that it based its costs of equity analysis on 12 utilities with "PCA or PCA-type mechanisms."

Q: HAVE YOU ANALYZED THE COMPANIES LISTED IN THIS RESPONSE TO DETERMINE WHETHER THEIR PCAS ARE SIMILAR TO THE ONE PROPOSED BY THE COMPANY?

A. Yes, I have conducted this analysis. At the outset, it must be noted the Response indicates no such mechanisms are in place for four of the twelve utilities at this time—Puget Sound Energy, PECO Energy, Sierra Pacific Resources and RGS Energy Group. That means the list offered by the company really includes 8 not 12 utilities. A more careful review of the Response and publicly available documents shows that only three of these utilities can be considered as having a PCA mechanism similar to what the Company is proposing in this case. For two of these companies, however, the mechanism is only applicable to a portion of their retail load (e.g., in certain states). For the third company, the current regulatory treatment is an interim step until a performance-based procurement mechanism is approved, which will likely occur no later than March, 2001. A description of the PCA mechanisms in effect for the identified companies is contained in Exhibit DWS-2.

With this additional and corrected information, it is clear the Company has not met the Commission standard of providing a cost-of-capital adjustment, nor has the Company chosen a group of utilities with comparable PCAs on which to base its costs of equity studies. Finally, I want to point out that many of these utilities are located in states where the legislature and/or the regulatory commissions have deregulated the electric industry, thereby providing a marketplace incentive for utilities to carefully manage all costs. It is also instructive to note that virtually all of the commissions regulating these companies have moved away from this type of mechanism. These commissions are using other regulatory methods, such as direct open market access, which fosters industry competition, or they use innovative, performance-based regulation. This Commission should recognize these developments and not adopt the Company's mechanism, which is a throw-back to an earlier day when all aspects of a utility's operations were regulated.

RECOVERY OF NON-RECURRING COSTS

Q. HOW SHOULD NON-RECURRING COSTS BE DEALT WITH IN DETERMINING THE COMPANY'S REVENUE REQUIREMENT?

A. The costs typically allowed in revenue requirements are described in well-accepted regulatory manuals and reference materials. For example, the National Association of Utility Regulatory Commissioners ("NARUC") publishes a Electric Utility Cost Allocation Manual, which addresses this issue in Chapter 3, Developing Total Revenue Requirements:

> Regulatory agencies recognize that the rates they establish are likely to remain in effect for an indeterminate period into the future. Consequently, rates so established are usually developed using the most current actual or projected cost and sales information for a selected period. The period used is normally 12 months in length — referred to as the test year or test period — and normally includes cost and sales data which are expected to be representative of those that will be experienced during the time the rates are likely to remain in effect.

Likewise, Leonard Saul Goodman's treatise notes that a regulatory agency routinely adjusts test year revenue for extraordinary events and other non-recurring costs, p. 287. The Process of Ratemaking, (1998)

Q. HAS THE COMPANY FOLLOWED THIS RATEMAKING PRINCIPLE AND EXCLUDED NON-RECURRING EVENTS FROM ITS REVENUE REQUIREMENTS?

A. No. The revenue requirement claimed by the Company includes the cost of several events that are either not likely to occur again at all or will not likely reoccur in the near future. As a result, these costs should be excluded from the proposed revenue requirement. These items include the cost associated with: 1) changing the name of the Company from Washington Water Power to Avista; 2) the 1996 Ice Storm; 3) the 1991 Fire Storm; and 4) Y2K preparedness.

The ratepayers received no benefit from the name change and therefore should not be required to pay for this cost. Of the remaining cost items, the most significant is the 1996 Ice Storm. The Company seeks to recover approximately $2.1 million because of ice-storm-related costs. This event, however, has been described as "extraordinary." Tr. at 511. The 1996 Fire Storm also was a "unique weather event unparalleled in the recorded weather history of this community." Exhibit 266 at 7.

If the Company wanted to seek recovery of this item in rates, it should have done so soon after the event by asking the Commission to establish a deferred account or to create a regulatory asset for this expense, thus, guaranteeing that it could recover this one-time charge in rates. The Company, however, failed to do so. Instead, it waited until the current proceeding to attempt to recover these costs. Furthermore, it seeks to treat these extraordinary events and items as if they were normal and should therefore become part of test year revenue requirements. I should further note that the Idaho Commission recently rejected Avista's request to recover the ice storm expenses. Idaho Order at 11.

For all these reasons, the costs associated with this event, and the other "one-time" costs, should not be included in the Company's revenue requirement. These combined costs have inappropriately increased the Company's proposed revenue requirement by $4.2 million. The Commission should not allow these costs to become embedded within the retail rates that arise from this proceeding.

If, however, the Commission chooses to allow recovery of some or all of these items, I strongly recommend that these amounts be amortized and tracked over a fixed period (e.g., 5 years) rather than let the Company recover these costs in perpetuity.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.