BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-99
DOCKET NO. UG-99

DIRECT TESTIMONY OF TARA L. KNOX
REPRESENTING AVISTA CORPORATION

WUTC
DOCKET NO. UE-991606
EXHIBIT # T-460
ADMIT W/D REJECT

Exhibit T-48

Q. Would you please state your name, business address and present position with Avista Corporation?

A. My name is Tara L. Knox. My business address is East 1411 Mission Avenue, Spokane, Washington. I am employed as a Rate Analyst in the Rates and Tariff Administration department.

Q. Would you briefly describe your duties?

A. I am responsible for preparing data for and maintaining the regulatory cost of service model for the Company as well as providing support in the preparation of Commission Basis results of operations and miscellaneous other duties as required.

Q. Would you briefly describe your educational background?

A. I graduated from Washington State University with a Bachelor of Arts degree in General Humanities in 1982 and a Master of Accounting degree in 1990. As an employee in the rate department of Avista Corp (and WWP) since 1991 I have attended several ratemaking classes including the EEI Electric Rates Advanced Course which specializes in cost allocation and cost of service issues.

Q. What is the scope of your testimony in these proceedings?

A. My testimony and exhibits will cover the Company's cost of service studies performed for these proceedings and the weather normalization adjustments to retail usage.

DOCKET NO. UE-99____ ELECTRIC SERVICE

Q. Would you please briefly summarize your electric system testimony?

A. I believe the base case cost of service study presented in this case includes the most accurate representation of the costs to serve each customer group. I have also provided the results of alternative scenarios to show the potential impact of different key allocation decisions in the cost of service process.

The base case study shows Residential Service Schedule 1 earns substantially less than the overall return under present rates. The Extra Large General Service Schedule 25 earns moderately less than the overall return. The Small General Service and Large General Service Schedules 11 and 21 earn substantially more than both the overall return and the requested return. Pumping Service Schedule 31 and Street and Area Lights show returns slightly above the overall return, but less than the requested return.

I also address unbundled costs by showing the component costs within the current rates, the component costs at the proposed revenues, and the full component costs if each customer group were providing the requested rate of return.

The weather normalization adjustment incorporates the effect of both heating and cooling on weather sensitive customer groups.

Q. Are you sponsoring any exhibits to be introduced in this proceeding?

A. Yes. I am sponsoring the following exhibits:

Exhibit No. 49, a flow chart illustrating the cost of service study process;

Exhibit No. 50, the complete output of the cost of service model showing the test year results of operations at present rates;

Exhibit No. 51, a methodology matrix showing the functionalization, classification and allocation selections used in the study presented as Exhibit No. 50;

Exhibit No. 52, summary results from the base case plus five alternate scenarios; and

Exhibit No. 53, unbundled functional cost comparison for present, proposed, and full cost.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes, they were.

ELECTRIC WEATHER NORMALIZATION

Q. Please describe the process used to arrive at the weather sensitive kWhs Mr. Hirschkorn includes in the Pro Forma Revenue Adjustment, and Mr. Norwood includes in the Power Supply Adjustment.

A. The weather adjustment is developed from regression analysis of five years of billed usage, billing period heating degree day and billing period cooling degree day data. The resulting weather sensitivity coefficients for each customer subgroup are multiplied by the average number of customers in each subgroup during the test period and the difference between normal heating/cooling degree days and test period observed heating/cooling degree days.

Q. Is this different from the method employed in the Company's prior cases?

A. This is a modification of the method utilized in the Company's last general rate case and semi-annual commission basis reports.

Q. Please explain.

A. The actual methodology has changed very little. The prior method did not include the effect of weather sensitive cooling. During the regression phase of the process, more combinations of variables are tested to arrive at the best fit. I also modified the time period used for the analysis to reflect exactly five heating seasons, July through June, rather than the five and a half heating seasons included in the prior method. The application of the results of the regression analysis is the same as the prior method, only now we apply both the difference between normal and actual <u>cooling</u> degree days as well as normal and actual <u>heating</u> degree days.

Q. Why was it important to include cooling sensitivity for this case?

A. Analysis of the billed usage data from recent years showed that summer weather sensitive usage has become significant for many of the customer groups. Additionally, the summer of 1998 was exceptionally hot, resulting in the retail system peak occurring on July 27, 1998. Without incorporating cooling sensitivity the prior method would have added usage during the summer due to fewer than normal heating degree days.

ELECTRIC COST OF SERVICE

Q. What is a cost of service study and what is its purpose?

A. A cost of service study is an engineering-economic study, which apportions the revenue, expenses, and rate base associated with providing electric service to designated groups of customers. It indicates whether the revenue provided by the customers recovers the cost to serve those customers. The study results are used as a guide in determining the appropriate rate spread among the groups of customers.

Q. Please briefly describe the process used in developing a cost of service study?

A. There are three basic steps involved in a cost of service study: functionalization, classification, and allocation. I have included a flow chart illustrating the process as Exhibit No. 49.

First, the expenses and rate base associated with the electric system under study are assigned to functional categories. The uniform system of accounts provides the basic segregation into production, transmission, and distribution. Traditionally customer accounting, customer information, and sales expenses are included in the distribution function and administrative and general expenses and general plant rate base are allocated to all functions.

Second, the expenses and rate base items which cannot be directly assigned to customer groups are classified into three primary cost components: energy, demand or customer related. Energy related costs are allocated based on each rate schedule's share of commodity consumption. Demand (capacity) related costs are allocated to rate schedules on the basis of each schedule's contribution to peak demand. Customer related items are allocated to rate schedules based on the number of customers within each schedule. The number of customers may be weighted by appropriate factors such as relative cost of metering equipment. In addition to these three cost components, any revenue related expense is allocated based on the proportion of revenues by rate schedule.

The final step is allocation of the costs to the various rate schedules utilizing the allocation factors selected for each specific cost item. These factors are derived from usage and customer information associated with the test period results of operations.

BASE CASE COST OF SERVICE

Q. What are the results of the Company's base case cost of service study?

A. The following table shows the rate of return and the ratio of the schedule return to the overall return (relative return ratio) at present rates for each rate schedule:

Customer Class	Rate of Return	Return Ratio
Residential Service Schedule 1	4.43%	0.59
Small General Service Schedule 11	12.51%	1.67
Large General Service Schedule 21	11.72%	1.56
Extra Large General Service Schedule 25	6.65%	0.89

Customer Class	Rate of Return	Return Ratio
Pumping Service schedule 31	7.67%	1.02
Lighting Schedules 41 - 49	8.68%	1.16
Total Washington Electric	7.51%	1.00

As can be observed from the above table, residential and extra large general service schedules (1 and 25) show under-recovery of the cost to serve them. The summary results of this study were provided to witness Hirschkorn as an input into development of the proposed rates.

Q. What is the basis for the cost of service study you have provided as Exhibit No. 50?

A. The cost of service study provided by the Company as Exhibit No. 50 is based on the 1998 test year pro forma results of operations presented by witness Falkner in Exhibit No. 28. Exhibit No. 50 will be discussed in more detail later in my testimony.

Q. Does the Company's base case cost of service study follow the methodology filed in the Company's last general rate case in Washington?

A. Some elements are from the methodology presented in Cause No. U-86-99, however, with two notable exceptions the methodology is closer aligned to the methodology approved for Puget Sound Power and Light (Puget Sound Energy) in Docket No. UE-920499.

Q. Please explain these two exceptions.

A. First, the peak credit theory for production and transmission costs is applied in essentially the same manner as the Company's last case, comparing replacement cost per kW for Avista's various production plant types, rather than adopting the one-half combustion turbine at 200 hours of operation unique to Puget's system. This study retains the theoretical assumptions regarding peak credit approved in the Puget case but applies it in a manner consistent with Avista's system. Second, administrative and general costs are directly assigned to functions where possible and the remaining general costs are included with the distribution function and classified 40% to energy and 60% to customer. In Puget's 1992 case most administrative and general costs were allocated by the sum of other operating expenses or labor or plant which implies a functional allocation based on the components of the sums.

Q. Why have you changed the methodology related to administrative and general costs?

A. One of the issues that became apparent through the Unbundled Cost Studies performed in response to Engrossed Second Substitute House Bill 2831 (E2SHB 2831) was the inadequacy of the "Other O&M" based allocation methodology to address the functional association appropriate for administrative and general costs. Under that methodology over 45% of administrative and general costs were allocated to the Production function which we consider an unreasonably large proportion.

Q. How does the method for dealing with administrative and general costs presented in the current study address this problem?

A. The method I have applied in this study first directly assigns administrative and general costs which have a direct association to the production, transmission, distribution, and customer relations functional units within the Company. These amounts are then allocated to customer groups using the proportions of related plant in service assigned and allocated to the customer groups (except customer relations which uses number of customers). The effect of using plant to allocate functionalized administrative and general costs gives recognition to the energy, demand, and customer allocations applied to plant in service.

The remainder of administrative and general costs support overall utility needs such as accounting, human resources, telecommunications, etceteras, which are necessary to the business but not directly associated with specific functions. These costs have been put in the category of Other and are considered separately. Just as these costs have no direct relationship to operating functions, neither do they have a direct relationship to customer groups. Careful consideration was given to develop what I believe is an appropriate "corporate" allocator for this category of costs which uses a combination of consumption and customer allocations.

Q. Please summarize the methodology applied to the base case study?

A. Exhibit No. 51 provides a methodology matrix summarizing the functionalization, classification and allocation choices implemented in this study. This study could be referred to as a Peak Credit, Basic Customer methodology with segregated A&G.

Q. Please explain the Peak Credit classification methodology applied to production and transmission costs in this study.

A. The Peak Credit methodology acknowledges that baseload production facilities provide energy throughout the year as well as capacity during system peaks and likewise the transmission system is built not only for peak use but everyday delivery of energy. The demand/energy ratio is determined by the relationship of the current replacement cost per kW generating capacity of a peaking unit (simple cycle combustion turbine) to the current replacement cost per kW generating capacity of the Company's thermal or hydro plant. The 1998 peak credit ratio for thermal plant is 28.20% to demand

and 71.80% to energy. The 1998 peak credit ratio for hydro plant is 28.73% to demand and 71.27% to energy. Transmission costs are classified by a fifty-fifty weighting of the thermal and hydro peak credit ratios resulting in the transmission peak credit ratio of 28.47% to demand and 71.53% to energy. Fuel and load dispatching expenses are classified entirely to energy. Peaking plant related costs are classified entirely to demand. Purchased Power and Other Power Supply expenses are classified to demand and energy by the relative amounts of assigned and allocated Production Plant in Service.

Q. Please explain the Basic Customer classification methodology applied to Distribution facilities related costs in this study.

A. The Basic Customer method considers only services and meters and directly assigned Street Lighting apparatus (FERC Accounts 369, 370, and 373 respectively) to be customer related distribution plant. All other distribution plant is then considered demand related. This division delineates plant which benefits an individual customer from plant which is part of the system. The basic customer method provides a reasonable, clearly definable division between plant that provides service only to individual customers from plant that is part of the interconnected distribution network. Additionally, the basic customer method has been explicitly accepted for both electric and gas cost of service in the State of Washington.

Q. How are customer service, customer information, and sales expenses treated in this study?

A. These costs are the core of the customer relations functional unit which is included with the distribution cost category. For the most part they are classified as customer related. Exceptions are demonstrating and selling expenses which are classified as energy related and uncollectible accounts expense which is considered separately as a revenue conversion item. Demand Side Management expenses recorded in Account 908 are also considered separately from the other customer information costs.

Q. Would you please discuss the treatment of demand side management in this study?

A. The Company's tariff rider, as discussed in witness Falkner's testimony, began in January 1995. The associated filing provided for accelerated amortization of the deferred balance at December 1994 beginning January 1995. The purpose of demand side management programs discussed in that proceeding was fourfold: (1) supply considerations, (2) a service to customers, (3) a conduit to achieve public policy, and (4) the Company's social responsibility to contribute to the conservation of natural resources. Given the purpose of the investment, I chose to include both the investment and amortization expense as a separate item in the distribution cost category. These costs were classified implicitly to demand and energy by the sum of production plant in service, then allocated to rate schedules by coincident peak demand and consumption respectively. The Schedule 91 Tariff Rider Revenue is included in the pro forma rate revenue. The offsetting expense recorded in account 908 is allocated to customers by the pro forma tariff rider revenue amount collected from each customer group effectively matching the revenue with the expense. Witness Folsom is presenting the cost-effectiveness analysis related to these costs.

Q. How are revenue related items treated in this study?

A. In this study state excise tax, uncollectible accounts, franchise fees and commission fees have been classified as revenue related and are allocated by pro forma revenue. These items vary with revenue and are included in the calculation of the revenue conversion factor. Income tax expense items are allocated to schedules by net income adjusted by interest expense. These items are then assigned to component cost categories for the functional summaries. The revenue conversion items have been reduced to a percent of all other costs and applied to each cost category by that ratio. Similarly, income tax items have been reduced to a percent of net income before tax then assigned to cost categories by relative rate base (as is net income).

Q. How are Other costs classified and allocated in this study?

A. As mentioned previously administrative and general costs which could not be directly associated with production, transmission, distribution, or customer relations functions were placed in the category of Other. A single allocation factor is applied to all of the amounts categorized as Other which is made up of a 40% weighting of annual kWh sales (energy classification) and a 60% weighting of average number of customers (customer classification). This factor was arrived at intuitively from a sense that most general costs, while not directly related to individual customers, are impacted by the number of transactions generated, which in turn is related to the number of customers served by the utility. For example, when there are more customers, there are more bills being processed, which cause more accounting transactions to be dealt with in the computer databases, where the size of individual transactions are irrelevant. However, some general costs will be impacted by the size of a customer. For example, budgeting and forecast will analyze the usage of thousands of small customers as a group, but will project the usage of large customers individually, simply because the impact on the utility of those individual customers is greater than the impact of individual small customers. The consumption allocator acknowledges the relative resources applied to customer groups for some aspects of general costs. The 60% customer, 40% energy weighting represents an estimate of how much of these general costs are of the first type compared to the second.

Q. Have you done any analysis looking at other customer/energy weightings?

A. Yes. I performed two alternative scenarios testing the impact of changing the weights in the customer/energy relationship. These scenarios are discussed in detail later in my testimony.

Q. How are demand related costs assigned to customer groups?

A. Production and transmission demand related costs are allocated to the customer classes by class contribution to the average of the twelve monthly system coincident peak loads. Although the Company is usually technically a winter peaking utility, it experiences high summer peaks and careful management of capacity requirements is required throughout the year. The use of the average of twelve monthly peaks recognizes that customer capacity needs are not limited to the heating season.

Distribution demand related costs which cannot be directly assigned are allocated to customer class by the average of the twelve monthly non-coincident peaks for each class. Distribution facilities that serve only secondary voltage customers are allocated by the non-coincident peak excluding primary voltage customers. This includes line transformers, services, and secondary voltage overhead or underground conductors and devices.

Q. How are energy related costs assigned to customer groups?

A. Energy related costs are allocated to class by pro forma annual kilowatthour sales adjusted for losses to reflect generation level consumption.

Q. How are customer related costs assigned to customer groups?

A. Most customer costs are allocated by average number of customers. Weighted customer allocators have been developed using typical current cost of meters, estimated meter reading time, and direct assignment of billing costs for hand-billed customers. Street and area light customers are excluded from metering and meter reading expenses as their service is not metered.

Q. Please describe what is shown in Exhibit No. 50?

A. The printouts from the Excel spreadsheet model used to calculate the cost of service are presented as Exhibit No. 50. This detail has been divided into three distinct segments.

Part 1 is the spreadsheet called "Proforma". The accounting data to be used in the study is entered here. Part 2 is the cost of service calculation from the spreadsheet called "Assign" showing the functionalization, classification, and allocation of each line item developed in "Proforma". The supporting schedules required to run the model made up of the allocation and classification factors used in the study are shown on pages 31 through 35.

Finally, Part 3 is the spreadsheet called "Sumcost". It consists of four summaries created from the information calculated in Part 2. The first summary labeled "Cost of Service Basic Summary" shows the results of the study by FERC account category with the rate of return by rate schedule and the ratio of each schedule's return to the overall return shown on Lines 58 and 59. The second summary labeled "Unbundled Cost Component Summary" shows the results of the study grouped into production, transmission, and distribution cost categories computed at present revenue, proposed revenue, and requested return applied uniformly to all customer groups. The third summary labeled "Functional Cost Summary" shows the items which make up the production, transmission, and distribution cost categories. The fourth summary labeled "Functional Cost Summary by Classification" shows the classification of costs within the production, transmission, and distribution cost categories.

ALTERNATIVE SCENARIO NO. 1

Q. Were the results of the base case methodology compared to the methodology from Cause No. U-86-99?

A. Yes, alternative scenario No. 1 shown in Exhibit No. 52 represents the results using the methodology applied in Cause No. U-86-99. The minimum distribution system customer classifications were estimated using the relationship of customer related plant to total plant by account in the 1986 case applied to 1998 plant balances. Most administrative and general expenses are allocated by the sum of other operating and maintenance expenses excluding purchased power and fuel accounts. General plant and plant related general operating expenses are allocated by the total of production, transmission, and distribution plant. As you can see by the relative return ratios shown in the table below the results are similar with some tradeoffs between small general service and lighting compared to large, extra large general, and pumping service.

Customer Group	Base Case	U-86-99	Difference
Residential	.59	.58	-0.01
Small General	1.67	1.54	-0.13
Large General	1.56	1.65	+0.09
Extra Large General	.89	.92	+0.03
Pumping	1.02	1.17	+0.15
Lighting	1.16	.93	-0.23

The increase in customer classification for distribution plant is largely offset by the decreased customer based allocation inherent in the A&G allocator providing similar results.

ALTERNATIVE SCENARIO NO. 2

Q. Was the Peak Credit assumption compared to other Production and Transmission theories?

A. Yes. The Peak Credit method heavily weights the energy classification. An alternative production/transmission theory which emphasizes demand classification was performed to provide a basis for comparison. I selected the straight fixed-variable approach which assumes all fixed costs are demand related and variable costs are energy related. The changes from base case are limited to production and transmission costs. All plant and plant related operating and maintenance expenses are considered fixed and classified as demand related. Purchased Power, Fuel, and Wheeling expenses are considered variable and classified as energy related. The results of this study are summarized under alternative scenario No. 2 on Exhibit No. 52. The table below compares the relative return ratios of the base case peak credit to straight fixed variable production and transmission cost classification theories.

Customer Group	Base Case	SFV	Difference
Residential	.59	.53	-.06
Small General	1.67	1.50	-.17
Large General	1.56	1.66	+.10
Extra Large General	.89	1.09	+.20
Pumping	1.02	1.21	+.19
Lighting	1.16	1.41	+.25

The heavy demand allocations favor large industrial customers with high load factors, seasonal irrigation and dusk to dawn lighting customers with limited contribution to coincident peaks, and are punitive to low load factor residential and small commercial customers.

ALTERNATIVE SCENARIO NO.3

Q. Was the Company's proposed method compared to the method approved in the Puget Sound Power and Light Docket No. UE-920499?

A. Yes. As the last Commission accepted methodology for Electric Cost of Service, next to the Company's last filed methodology, the Puget Method provides a necessary comparison for deviations from it. The primary differences between the Company Base Case and the Puget Method include the definition of peak credit at one-half of a CT compared to a CCCT, coincident peak demand measured by the 200 highest use hours, and Administrative and General Costs allocated primarily by the sum of other O&M expenses or labor. Neither the ½CT/CCCT comparison, nor the 200 peak hours are relevant to Avista's predominantly hydro based operations, so we have applied the peak credit ratio of 13% demand, 87% energy directly from Puget's order, and estimated the 200 hour peak in the same manner as presented in the Unbundled Cost Study for E2SHB 2831. The results of this study are summarized under alternative scenario No. 3 on Exhibit No. 52.

Customer Group	Base Case	Puget	Difference
Residential	.59	.74	+.16
Small General	1.67	1.72	+.06
Large General	1.56	1.39	-.18
Extra Large General	.89	.67	-.22

Customer Group	Base Case	Puget	Difference
Pumping	1.02	.97	-.05
Lighting	1.16	.81	-.35

Results are almost directly opposed to the straight fixed variable scenario in that the emphasis on energy has the opposite effect on high and low load factor customers as the emphasis on demand from the previous alternative. This effect is exacerbated by the administrative costs following the allocation of other plant and expenses which are highly dependent on the usage based allocations.

ALTERNATIVE SCENARIOS NO. 4 AND NO. 5

Q. Were results using alternative customer and energy weights for the Other cost category compared against the base case?

A. Yes. In an attempt to show the potential impact of modifying the weights applied to customer and energy portions of the allocator used for the "Corporate Cost Allocator" in the base case study the two extreme cases were prepared. Exhibit No. 52 alternative scenarios No. 4 and No. 5 represent the results of this study keeping everything the same as the base case except for the customer/energy weights applied to general costs. Alternative No. 4 shows the extreme weighting 100% customer and Alternative No. 5 the opposite with 100% energy. The table below shows a comparison of the relative return ratios for the Base Case and the two extreme cases.

Customer Group	Base Case	Customer	Energy	Cust - Base Difference	Energy - Base Difference
Residential	.59	.48	.76	-.11	+.17
Small General	1.67	1.61	1.76	-.06	+.09
Large General	1.56	1.71	1.35	+.15	-.21

Customer Group	Base Case	Customer	Energy	Cust - Base Difference	Energy - Base Difference
Extra Large General	.89	1.07	.62	+.18	-.27
Pumping	1.02	1.13	.86	+.11	-.16
Lighting	1.16	1.20	1.09	+.04	-.07

The Residential Service Schedule consistently shows under recovery of the cost to serve them even given the beneficial extreme with emphasis on energy allocations. Extra Large General Service slightly exceeds unity given the beneficial extreme with emphasis on customer allocations. Pumping Service, which is nearly at unity in the base case, evenly straddles unity in the extreme cases. The other customer groups consistently show over recovery of the cost to serve them.

Q. Please provide a summary table comparing all the alternative cost study results prepared for this case.

A. The following table compares the relative rate of return ratios produced by each alternative costing methodology prepared for this case and shown in the result summary provided as Exhibit No. 52.

Customer Group	Base Case	U-86-99	SFV	Puget	Customer	Energy
Residential	.59	.58	.53	.74	.48	.76
Small General	1.67	1.54	1.50	1.72	1.61	1.76
Large General	1.56	1.65	1.66	1.39	1.71	1.35
Extra Large General	.89	.92	1.09	.67	1.07	.62
Pumping	1.02	1.17	1.21	.97	1.13	.86
Lighting	1.16	.93	1.41	.81	1.20	1.09

Consistently, no matter which variation you look at, Residential (Schedule 1) customers are providing less than the cost to serve them. General Service (Schedules 11 and 21) customers are consistently providing above the overall return. The base case methodology produces conservative results in the sense that the cost relationships fall in the middle of the range produced by the alternative methodologies.

UNBUNDLED COST ANALYSIS

Q. How was the issue of unbundled costs addressed in this study?

A. The functionalization process which is the first step in a cost of service study provides the framework for analysis of unbundled revenue responsibility. The study examines rate base and expenses from which it determines rate of return by customer group given revenues from existing rates. The component costs in the study can be summarized into desired unbundled cost categories with the return component (net income by customer group) assigned by relative rate base for each component. The result of this analysis, presented on lines 1 through 8 of Exhibit No. 53, represents the unbundled cost components of current rates. This is different from the concept of unbundled cost as it was measured in the studies presented for E2SHB 2831.

Q. How were unbundled costs defined in the E2SHB 2831 studies?

A. The overall return for the Washington Jurisdiction was applied uniformly to all cost components for all customer groups based on relative rate base to represent the full embedded cost of service for each component. Revenue and income related expenses, namely uncollectibles, commission and franchise fees, and excise and income taxes were assigned to customer groups as if each group were contributing precisely the revenue required to produce the overall return.

Q. Have you computed the full component cost as interpreted in the Unbundled Cost Studies?

A. Yes. I applied the requested rate of return uniformly to the rate base components from the base case and adjusted revenue related expenses and income tax to match the requested revenue requirement in this case. The production cost includes a weighted return component acknowledging the additional return requested for the renewable resources equity adder. These adjusted amounts were added to the expenses from the base case to represent the full embedded cost of service for each cost component. The results are shown on lines 17 through 24 of Exhibit No. 53. For comparison purposes I also computed the component costs assuming revenues from the proposed rate design. These results are shown on lines 9 through 16 of Exhibit No. 53.

Q. What costs are included in the production category?

A. The following costs have been included in the production category:

- Production related Operating and Maintenance Expenses
- Administrative and General Expenses assigned to Production
- Depreciation and Amortization Expenses associated with Production Rate Base
- WNP-3 Settlement Exchange Power cost
- Property taxes associated with Production Plant and kWh Generation taxes
- Proportionate share of Income Taxes
- Proportionate share of Uncollectibles, Commission Fees, Franchise Fees, and Excise Tax
- Weighted Return on Production Rate Base

- Reduced by Other Operating Revenues associated with Production or Power Supply.

Q. What costs are included in the transmission category?

A. The following costs have been included in the transmission category:

- Transmission related Operating and Maintenance Expenses
- Administrative and General Expenses assigned to Transmission
- Depreciation and Amortization Expenses associated with Transmission Rate Base
- Property taxes associated with Transmission Plant
- Proportionate share of Uncollectibles, Commission Fees, Franchise Fees, and Excise Tax
- Proportionate share of Uncollectibles and Commission Fees
- Return on Transmission Rate Base
- Reduced by Other Operating Revenues associated with Transmission.

Q. What costs are included in the distribution category?

A. The following costs have been included in the distribution category:

- Distribution related Operating and Maintenance Expenses
- Customer Relations related Operating Expenses
- Administrative and General Expenses assigned to Distribution, Customer Relations, and Other
- Demand Side Management expenses
- Depreciation and Amortization Expenses associated with Distribution and General Rate Base

- Property taxes associated with Distribution or General Plant and miscellaneous Distribution taxes
- Proportionate share of Income Taxes
- Proportionate share of Uncollectibles, Commission Fees, Franchise Fees, and Excise Tax
- Return on Distribution Rate Base
- Return on Demand Side Management Rate Base
- Reduced by Other Operating Revenues associated with Distribution.

Q. What is the significance of the unbundled cost analysis?

A. In the past several years the Company has embarked on several experiments involving the segregation of the provision of power from the delivery of it, namely Direct Access Delivery Service, and More Options for Power Service I and II. Component cost analysis provides a beginning point for determining the appropriate amounts to apply toward the segregated parts. Further, comparison of the component costs reflected in the proposed rate design to the same component costs at uniform return provides perspective on the difference between rates and cost. This analysis, on an unbundled basis, also illustrates the movement toward more accurately reflecting the cost for residential and extra large general service customers proposed in this case.

Q. Does this conclude your direct testimony related to Docket No. UE-99__?

A. Yes, it does.

DOCKET NO. UG-99 NATURAL GAS SERVICE

Q. Would you please briefly summarize your natural gas system testimony?

A. The cost of service study presented in this case for the most part follows the methodology approved in Docket No. UG-940814 for the Washington Natural Gas Company pertaining to rate base and expenses exclusive of purchased gas and underground storage costs. The study follows the current Avista Corp gas tracker methodology for purchased gas and underground storage costs. The study shows residential and large general service rate schedules earning less than the overall return. The small general service and transportation schedules while earning more than the overall return are still earning less than a desired return. The study shows the interruptible service schedule earning more than the overall return.

Q. Are you sponsoring any exhibits to be introduced in this proceeding?

A. Yes. I am sponsoring the following exhibits:

Exhibit No. 54, a flow chart illustrating the cost of service study process

Exhibit No. 55, the complete output of the cost of service model showing the test year results of operations at present rates

Exhibit No. 56, a summary showing the derivation of the approved allocation methodology from the Washington Natural case

Exhibit No. 57, a detailed description of the allocation factors used in the study presented as Exhibit No. 55.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes, they were.

NATURAL GAS WEATHER NORMALIZATION

Q. Please describe the process used to arrive at the weather sensitive therms Mr. Hirschkorn includes in the Pro Forma Revenue / Gas Supply adjustment?

A. The weather adjustment is developed from regression analysis of five and one-half years of billed usage and billing period heating degree day data. The resulting weather sensitivity coefficient for each customer subgroup is multiplied by the average number of customers in the subgroup during the test period and the difference between normal heating degree days and test period heating degree days.

Q. Is this different from the method employed in the Company's prior cases?

A. This method was utilized in the Company's 1997 general rate case as well as the 1990 general rate case and for semi-annual commission basis reporting.

Q. The Company is proposing to modify the weather normalization methodology for electric usage, why not for natural gas usage as well?

A. The change to the electric methodology was necessary to reflect the impact of air conditioning load during the summer months. Natural gas is not used for air conditioning, the usage per customer data shows no cooling sensitivity and the current regression fit statistics for the weather sensitive subgroups are excellent. Therefore, there is no need to change the existing methodology.

NATURAL GAS COST OF SERVICE

Q. What is a cost of service study and what is its purpose?

A. A cost of service study is an engineering-economic study which apportions the revenue, expenses, and rate base associated with providing natural gas service to designated groups of customers. It indicates whether the revenue provided by the customers recovers the cost to serve those customers. The study results are used as a guideline in determining the appropriate rate spread among the groups of customers.

Q. Please briefly describe the process used in developing a cost of service study?

A. There are three basic steps involved in a cost of service study: functionalization, classification, and allocation. I have included a flow chart illustrating the process as Exhibit No. 54.

First, the expenses and rate base associated with the natural gas system under study are assigned to functional categories. The uniform system of accounts provides the basic segregation into production, underground storage, and distribution. Traditionally customer accounting, customer information, and sales expenses are included in the distribution function and administrative and general expenses and general plant rate base are allocated to all functions.

Second, the expenses and rate base items are classified into three primary cost components: demand, commodity or customer related. Demand (capacity) related costs are allocated to rate schedules on the basis of each schedule's contribution to system peak demand. Commodity (energy) related costs are allocated based on each rate schedule's share of commodity consumption. Customer related items are allocated to rate schedules based on the number of customers within each schedule. The number of customers may be weighted by appropriate factors. In addition to these three cost components, any revenue related expense is allocated based on the proportion of revenues by rate schedule.

The final step is allocation of the costs to the various rate schedules utilizing the allocation factors developed for each specific cost item.

Q. What is the basis for the cost of service study you have provided as Exhibit No. 55?

A. The cost of service study provided by the Company as Exhibit No. 55 is based on the 1998 test year pro forma results of operations presented by witness Falkner in Exhibit No. 30. Exhibit No. 55 will be discussed in more detail later in my testimony.

Q. Does the Company's cost of service study in this case utilize the same methodology presented in Avista's previous Gas Case Docket No. 971071?

A. Yes, the methodology is exactly the same.

Q. Is this methodology comparable to the methodology approved in Docket No. UG-940814 for Washington Natural Gas Company?

A. Yes, except for purchased gas and underground storage costs, this study follows the methodology prescribed in the Fifth Supplemental Order from Docket No. UG-940814. Exhibit No. 56 shows the derivation of the Washington Natural approved methodology from the Company, Staff, and Public Counsel proposals in that case.

Q. Why didn't the Company use the Washington Natural Gas case methodology for purchased gas and storage costs?

A. The Company approached the 97 case with the intent to avoid controversy as much as possible. We started with the idea to utilize the most recent Commission approved cost of service methodology. This approach works well for the basic distribution system rate base and operating and maintenance expenses which are organized through the uniform system of accounts into comparable items. Each item can be lined up with its counterpart from another company with reasonable assurance that the comparison will not be an issue.

Purchased gas costs, however, are specific to each local distribution company. Different companies have unique commodity and transportation portfolios designed to serve the specific load characteristics of their customer base. In light of the inherent differences between the companies, and in an effort to minimize issues, we elected to use the last Commission approved gas cost allocation methodology specific to the Avista Corp system. Pipeline charges related to underground storage are included in the gas costs. It would be inconsistent to apply one methodology to underground storage related costs which fall into account 804, then apply another methodology to underground storage rate base and operating and maintenance expenses.

Q. What methodology was used to allocate purchased gas and underground storage costs?

A. Purchased gas costs and underground storage costs use the methodology established in Washington Water Power Docket No. UG-901459 as modified by Docket No. UG-951339. The modification removed most of the pipeline demand charges from Schedule 146 Transportation rates, and provided for direct billing of these costs to customers with existing buy/sell arrangements. This change was similar to that approved in the Washington Natural Gas Company rate case.

Q. Would you please briefly explain the methodology used to allocate each type of costs?

A. Purchased gas costs are allocated based on the demand and commodity weighted average cost of gas (WACOG) components of the purchased gas adjustment in effect since December 1, 1998. This is consistent with the calculation of pro forma gas costs as will be discussed in more detail in witness Hirschkorn's testimony. Gas schedulers' labor has been separated out of purchased gas expenses. The schedulers' labor is allocated by throughput. The remainder of account 807 is allocated by sales therms.

Underground storage operating and maintenance expenses and rate base are classified 77% to commodity, and 23% demand. The commodity portion is allocated to rate schedule by pro forma throughput excluding Schedule 148 special contract customers. The demand portion is allocated by firm coincident peak demand.

Distribution operating and maintenance expenses are allocated by the plant items to which they relate with the exception of load dispatching expenses which are allocated by total throughput, and other distribution expense and rents which are allocated by the sum of all other distribution expenses. Distribution rate base falls into two primary categories; items which are classified as 55% demand related and 45% commodity related per the peak and average ratio, and items which are classified as customer related. Demand related components are allocated by coincident peak demand, commodity related components by throughput. The customer related plant is either directly assigned or allocated by weighted average cost.

All customer accounting, customer service and information, and sales expenses are allocated by number of customers with the following two exceptions. Uncollectibles account 904 is allocated by pro forma revenue. The demand side management amortization expense portion of account 908 is classified as demand and commodity by the peak and average ratio then allocated by coincident peak demand and throughput respectively. This matches demand side management investment which is functionalized to distribution.

General and intangible plant is allocated based on all other plant. Administrative and general expenses are segregated into plant related, labor related, revenue related and other. Plant related items are allocated based on plant in service. Labor related items are allocated by operating and maintenance labor expense. Revenue related items are allocated by pro forma revenue. Other administrative and general expenses are allocated 50% by throughput and 50% by total operating and maintenance expense before administrative and general expenses excluding purchased gas cost.

Deferred income taxes are allocated by plant in service. Contributions in aid of construction are directly assigned to Schedule 101 residential customers. Depreciation and property taxes are allocated by the associated plant. Excise tax is allocated by pro forma revenue and income tax is allocated by net income before income tax. Exhibit No. 57 describes in detail how each line item has been classified and allocated.

Q. How are purchased gas costs allocated within the WACOG calculation?

A. Purchased gas costs are allocated several different ways. Northwest Pipeline transportation demand costs (TF-2) related to the Company's storage projects are allocated 77% by customer throughput, excluding Schedule 148 customers and 23% by firm coincidental peak based on a 3 year rolling, 5 day firm coincidental peak. Gas commodity costs are allocated to sales schedules based on monthly throughput. Northwest Pipeline demand costs associated with the Plymouth storage project are allocated to firm schedules based on the 3 year rolling, 5 day firm coincidental peak. Pipeline transportation demand costs are first directly assigned to transportation customers who have entered into buy/sell arrangements with the Company and then netted against capacity releases. Ninety percent of the remaining demand costs are allocated to sales customers based upon throughput while ten percent are allocated to firm sales customers based on the three year rolling, 5 day coincident peak allocator. Pages 5 through 7 of Exhibit No. 57 show the purchased gas tracker calculation.

Q. Would you please explain the peak and average calculation?

A. Coincident Peak is determined as prescribed in Washington Water Power Docket No. UG-901459 and as used in the Company tracker calculations. This consists of the average of the 5 day sustained peak over three years. The average daily therms computed from the pro forma annual throughput is divided by the 3 year average peak to arrive at the annual load factor of 45%. This amount is considered commodity related. The difference between the peak and the average daily usage is divided by the peak to arrive at the peak load factor of 55%. This amount is considered demand related.

Q. How does this calculation compare to the method described in the Washington Natural Order?

A. The calculation of the peak and average ratio matches the staff method which was accepted in the Washington Natural Gas rate case. The 3 year average peak calculation used for the Company tracker calculations differs from the Washington Natural Gas method in that the Company calculation uses the 5 day sustained peak for the 3 year average rather than the five individual peak days for three years. Since the gas costs are allocated using this definition of peak demand, and the methods both smooth the peaks over fifteen days in three years, I chose to simplify the process by applying the same peak definition to demand related distribution costs as is used to allocate the Company's gas costs.

Q. Have distribution mains been segregated into small and large as was done in the Washington Natural Gas rate case?

A. Yes. An engineering study was performed to determine the size and original cost of mains and services dedicated to transportation and interruptible customers as well as indicating the size of system main to which they are connected. The classification of small mains as less than 4 inches and large mains as 4 inches or greater was used in the Washington Natural Gas case and is followed in this study. Dedicated main is directly assigned to Schedules 131, 146, and 148. The remaining small mains are classified into demand and commodity by the peak and average ratio, then allocated by coincident peak demand and throughput excluding the demand and usage of the interruptible and transportation customers not connected to smaller than 4 inch main. The remaining large mains are classified into demand and commodity by the peak and average ratio, then allocated by coincident peak demand and throughput to all schedules.

Q. How were the weighted average cost allocators for customer related distribution plant determined?

A. An engineering study was performed detailing typical meter installation set-ups for various size meters and average length of service installations by size of pipe at current cost. Type of meter by schedule was applied to the current cost information to obtain the weighted average cost per customer for meters, house regulators, customer installations and industrial measuring and regulating equipment installations. Services are directly assigned to interruptible and transportation customers from the study used to directly assign dedicated main, the remainder of the plant is allocated by customers weighted by typical service installation at current cost.

Q. Are there items specific to this study which were not discussed in the Washington Natural Order?

A. There were two categories of costs for which the Washington Natural Order did not provide guidance on allocation methodology. Demand side management was not an issue in the Washington Natural case and revenue related items were allocated differently by the parties while the order was silent on the preferred treatment.

Q. Would you please discuss the treatment of demand side management in this study?

A. The tariff rider filing in 1994 provided for amortization of the deferred balance at December 1994 beginning January 1995. The purpose of demand side management programs discussed in that proceeding was fourfold: supply considerations, a service to customers, a conduit to achieve public policy, and the Company's social responsibility to contribute to the conservation of natural resources. Given the purpose of the investment, I chose to treat both the investment and amortization expense as a distribution cost. These costs were classified to demand and commodity by the peak and average ratio, then allocated to rate schedules by coincident peak demand and throughput respectively.

Q. How are revenue related items treated in this study?

A. In this study uncollectibles, franchise fees, commission fees, and Washington state excise taxes have been classified as revenue related and are allocated by pro forma revenue. These items vary with revenue and are included in the calculation of the revenue conversion factor.

Q. Please describe what is shown in Exhibit No. 55?

A. The printouts from the Excel spreadsheet model used to calculate the cost of service is included as Exhibit No. 55. This detail has been divided into four distinct segments.

Part 1 is the spreadsheet called "Proforma". The accounting data to be used in the study is entered here. Part 2 is the cost of service calculation from the spreadsheet called "Assign" showing the classification and allocation of each line item developed in "Proforma". Part 3 consists of the supporting schedules required to run Part 2 also from the spreadsheet called "Assign". The allocation and classification factors used in the study are entered or calculated on these worksheets.

Finally, Part 4 is the spreadsheet called "Sumcost". It consists of three summaries created from the information calculated in Part 2. The general summary shows the basic results of the study by FERC account category with the rate of return by rate schedule and the ratio of each schedule's return to the overall return shown on Lines 56 and 57. Next is a functional summary showing the same information organized into production, underground storage, distribution, and a separate category for customer service, information, and sales which would traditionally be included in distribution. The second page of this summary is the same information on a cost per therm basis. The third summary shows the results of the study organized by cost classification with the unit cost for each classification.

Q. What are the results of the Company's cost of service study?

A. The following table shows the rate of return and relative return ratio at present rates for each rate schedule:

Customer Class	Rate of Return	Return Ratio
Residential Service Schedule 101	7.07%	0.95
Small General Service Schedule 111	8.55%	1.15
Large General Service Schedule 121	5.71%	0.77
Interruptible Sales Service Schedule 131	11.67%	1.57
Transportation Service Schedule 146	8.83%	1.19
Special Contracts Schedule 148	8.50%	1.14
Total Washington Gas	7.42%	1.00

As can be observed from the above table, with the exception of schedules 121 and 131, most Schedules provide returns close to the overall return. The summary results of this study were provided to witness Hirschkorn as an input into development of the proposed rates.

Q. Does this conclude your direct testimony related to UG-99____?

A. Yes, it does.