BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-05-__

DOCKET NO. UG-05__

DIRECT TESTIMONY OF

BRIAN J. HIRSCHKORN

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

Q. Please state your name, business address and present position with Avista Corporation?

A. My name is Brian J. Hirschkorn and my business address is 1411 East Mission Avenue, Spokane, Washington. I am presently assigned to the State and Federal Regulation Department as Manager of Pricing.

Q. Would you briefly describe your duties?

A. My primary areas of responsibility include electric and gas rate design, customer usage and revenue analysis, and tariff administration.

Q. Would you briefly describe your educational background?

A. I am a 1978 graduate of Washington State University with Bachelor degrees in Business Administration and Accounting.

Q. Have you previously testified before the Commission?

A. Yes. I have testified before this Commission in several prior rate proceedings as a revenue and rate design witness.

Q. What is the scope of your testimony in this proceeding?

A. My testimony in this proceeding will cover the spread of the proposed annual electric revenue increase of $35,833,000, or 12.5%, among the Company's electric general service schedules. With regard to natural gas service, I will describe the spread of the proposed annual revenue increase of $2,943,000, or 1.8%, among the Company's natural gas service schedules. My testimony will also describe the design of the proposed rates within the

Company's electric and natural gas service schedules. I am also responsible for the revenue normalization adjustments for both electric and natural gas, which I will briefly discuss.

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

A. Yes. I am sponsoring Exhibit Nos.__(BJH-2), __(BJH-3), and __(BJH-4) related to the proposed electric increase, and Exhibit Nos.__(BJH-5), __(BJH-6), and __(BJH-7) related to the proposed natural gas increase. I am also sponsoring Exhibit No.__(BJH-8), which reflects the Company's electric and natural gas energy efficiency programs. I will discuss these Exhibits in more detail later in my testimony.

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II. EXECUTIVE SUMMARY

Proposed Electric Increase

Q. What is the proposed electric revenue increase in this Case and how is the Company proposing to spread the increase by rate schedule?

A. The proposed electric increase is $35,833,000 million, or 12.5% over present base tariff revenue/rates in effect. The proposed increase by rate schedule is as follows:

Residential Service Schedule 1	14.3%
General Service Schedules 11 & 12	8.8%
Large General Service Schedules 21 & 22	10.5%
Extra Large General Service Schedule 25	13.3%
Pumping Service Schedules 31 & 32	12.0%
Street & Area Lighting Schedules 41-49	11.0%

This information is shown in detail on Page 1 of Exhibit No. __(BJH-4).

Q. What is the basis for the proposed increase by rate schedule?

A. The Company used the results of the cost of service study, as sponsored by Company Witness Knox as a guide in spreading the proposed increase ($35.8 million) by service (rate) schedule. The spread of the proposed revenue increase, as shown on Page 1 of Exhibit No. __(BJH-4), results in moving the relative rates of return for the individual rate schedules one-third toward unity (1.00). The rates of return for the individual schedules are shown on Page 2 of Exhibit No. __(BJH-4).

Q. What is the proposed increase for a residential electric customer with average consumption?

A. The proposed increase for a residential customer using an average of 1,000 kwhs per month is $7.92 per month, or a 14.4% increase in their electric bill. As part of that increase, the Company is proposing that the basic / customer charge be increased from $5.00 to $5.50 per month. The present bill for 1,000 kwhs is $55.09 compared to the proposed level of $63.01, including all present rate adjustments.

Q. Is the Company proposing any significant changes to the design of the rates <u>within</u> any of its electric service schedules?

A. Yes. The Company is proposing to add an energy usage rate block to its large and extra large electric general service schedules (Schedules 21 and 25), whereby the larger customers served under those schedules would pay a lower incremental energy rate for usage beyond a certain level. These proposals are reasonable and appropriate from a cost of service basis, and result in rates that are more fair and equitable between those schedules. The result is that the proposed increase for customers within a Schedule will vary depending on the customer's usage.

Q. Where in your Exhibits do you show the proposed changes in rates within the electric service schedules?

A. This information is shown in detail on page 3 of Exhibit No. __(BJH-4).

<u>Proposed Natural Gas Increase</u>

Q. How is the Company proposing to spread the overall natural gas increase of $2,943,000, or 1.8%, by service schedule?

A. The Company is proposing the following revenue/rate changes by rate schedule:

General Service Schedule 101	2.1%
Large General Service Schedule 111	0.8%
High Annual Load Factor – Lg. General Service Sch. 121	0.7%
Interruptible Sales Service Schedule 131	(3.2%)
Transportation Service Schedule 146	2.2%*

*Excludes the cost of gas and pipeline transportation – customers served under Transportation Schedule 146 secure their own gas and pipeline transportation.

This information is also shown on Page 1 of Exhibit No. __(BJH-7). The proposed increase by rate schedule results in rates of return for each schedule very close to the cost of providing service (unity), as shown on page 2 of Exhibit No. __(BJH-7).

Q. What is the proposed monthly increase for a residential natural gas customer with average usage?

A. The increase for a residential customer using an average of 75 therms of gas per month would be $1.48 per month, or 2.0%. A bill for 75 therms per month would increase from the present level of $74.77 to a proposed level of $76.25, including all present rate adjustments.

III. PROPOSED ELECTRIC REVENUE INCREASE

Revenue Normalization

Q. Would you please describe the electric "revenue normalization adjustment" which you have referred to?

A. Yes. The electric revenue normalization adjustment represents the difference between the company's actual recorded retail revenues during the 2004 test period and retail revenues on a normalized (pro forma) basis. The total revenue normalization adjustment increases Washington net operating income by $921,000 as shown in column (y) on page 7 of Exhibit No. __(DMF-2). The revenue normalization adjustment consists of three primary components: 1) repricing customer usage (adjusted for known and measurable changes) at present base tariff rates in effect, 2) adjusting customer loads and revenue to a calendar-year basis (unbilled revenue adjustment), and 3) weather normalizing customer usage and revenue.

Q. Is the calculation of the revenue adjustment associated with the three components listed above the same as was used in the Company's last general case?

A. Yes, it is.

<u>Summary of Electric Rate Schedules and Tariffs</u>

Q. Would you please explain what is contained in Exhibit No. __(BJH-2)?

A. Exhibit No. __(BJH-2) is a copy of the present electric service schedules on file with the Commission as part of the Company's tariff, WN U-28.

Q. Turning now to Exhibit No. __(BJH-3), would you please state what is contained in that Exhibit?

A. Exhibit No. __(BJH-3) contains the proposed tariff sheets that are being filed with the Commission.

Q. Could you please explain what is contained in Exhibit No. __(BJH-4)?

A. Exhibit No. __(BJH-4) contains information regarding the proposed rate spread and rate design of the proposed revenue components in this case. Page 1 shows the proposed general revenue and percentage increase by rate schedule compared to the present revenue under base tariff rates (excluding the present power cost surcharge and other rate adjustments), as well as the proposed percentage increase compared to present revenue under billing rates, including all rate adjustments. Page 2 shows the rates of return by rate schedule before and after application of the proposed general increase, based on the cost of service information presented by Company Witness Knox. Page 3 shows the present billing rates under each of the rate schedules, the proposed changes to the rates within the schedules, and the proposed rates after application of the changes. These pages, as well as the other pages contained in Exhibit __(BJH-4), will be referred to later in my testimony.

Q. Why do you compare the proposed revenue increase(s) to both present revenue under base tariff rates and revenue under present billing rates?

A. Typically, proposed rate spread and rate design information is shown as compared to revenue and rates under base tariff rates, which exclude any temporary rate adjustments, such as the Company's present power cost (ERM) surcharge. However, the percentage change(s) that customers will see on their bills will be based on present rates including the present ERM surcharge and other rate adjustments. The Company believes that it is also important to provide the information as it will ultimately affect customer bills.

Q. Would you please describe the Company's present rate schedules and the types of electric service offered under each?

A. Yes. The Company presently provides electric service under Residential Service Schedule 1, General Service Schedules 11 and 12, Large General Service Schedules 21 and 22, Extra Large General Service Schedule 25, and Pumping Service Schedules 31 and 32.

Additionally, the Company provides Street Lighting Service under Schedules 41-46, and Area Lighting Service under Schedules 47 and 48. Schedules 12, 22, 32, and 48 exist for residential and farm service customers who qualify for the "Residential Exchange" program operated by the Bonneville Power Administration. The rates for these schedules are identical to the rates for Schedules 11, 21, 31, and 47, respectively, except for the present Residential Exchange rate credit of 0.421 cents per kwh, as set forth under Schedule 59 of the Company's tariff. The following table shows the type and number of customers served in Washington (as of December 2004) under each of the general service schedules:

Schedule	Type of Customer	No. of Customers
Residential Sch. 1	Residential	188,000
General Sch. 11&12	Small Commercial / less than 50 kw	25,000
Lge. General Sch. 21&22	Med. - Lge. Comm. & Industrial / over 50 kw	3,400
Ex. Lge. General Sch. 25	Lge. Comm. & Industrial / over 3,000 kva	20
Pumping Sch. 31&32	Water & Effluent Pumping	2,100

Proposed Electric Rate Spread

Q. How does the Company propose to spread the total revenue increase request of $35,833,000 among its various rate schedules?

A. The Company is proposing the following (base tariff) revenue / rate increase(s) by service schedule:

Proposed Increase by Rate Schedule

Residential Service Schedule 1	14.3%
General Service Schedules 11 & 12	8.8%
Large General Service Schedules 21 & 22	10.5%
Extra Large General Service Schedule 25	13.3%
Pumping Service Schedules 31 & 32	12.0%
Street & Area Lighting Schedules 41-49	11.0%

This information is also shown on Page 1 of Exhibit No. __(BJH-4). The proposed revenue increases shown in the table above compare to an overall revenue increase of 12.3% over base tariff revenue if applied uniformly to each of the schedules.

Q. What rationale did the Company use in this proposed spread of the overall general revenue increase to the various service schedules?

A. The Company utilized the results of the cost of service study, as sponsored by Company Witness Knox, as a guide in developing the proposed rate spread. The primary goal of the proposed rate spread is to move the rates of return of the individual service schedules closer to the overall rate of return (unity), so that all customers contribute fairly to the cost of providing service. The table below shows the relative rates of return by schedule before and after the proposed increases are applied. The relative rate of return is determined by dividing the rate of return for each schedule by the overall rate of return for the Company's Washington electric operations. This information is also shown on Page 2 of Exhibit No. __(BJH-4).

Relative Rates of Return by Service Schedule

	Before Increase	After Increase
Residential Service Schedule 1	0.61	0.75
General Service Schedules 11 & 12	1.91	1.60
Large General Service Schedules 21 & 22	1.53	1.35
Extra Large General Service Schedule 25	0.66	0.77
Pumping Service Schedules 31 & 32	1.06	1.04
Street & Area Lighting Schedules 41-48	1.14	1.10

Application of the proposed revenue increase by schedule was based on moving the relative rate of return approximately one-third toward unity (1.00) after application of the increase.

Q. Why is the Company proposing a spread of the proposed general rate increase that results in the relative rates of return moving one-third toward unity?

A. Given the present disparity between the relative rates of return by rate schedule, as well as other rate design considerations in the filing, the Company believes that reducing that disparity by one-third in this proceeding is a reasonable balance between moving the rates toward cost of service and other considerations. These other considerations include the overall level of the proposed electric increase (12.5%), as well as the proposed rate design changes for Schedules 21 and 25, discussed later in my testimony.

<u>Proposed Rate Design</u>

Q. Where in your Exhibits do you show a comparison of the present and proposed rates within each of the Company's electric service schedules?

A. Page 3 of Exhibit No. __(BJH-4) shows a comparison of the present and proposed rates within each of the schedules, which I will describe below. Column (a) shows the rate/ billing components under each of the Schedules, column (b) shows the base tariff rates within each of the schedules, column (c) shows the present rate adjustments (additions and credits) applicable under each schedule, and column (d) shows the present billing rates. Column (e) shows the proposed general rate increase to the rate components within each of the schedules, column (f) shows the proposed <u>billing</u> rates and column (g) shows the proposed <u>base</u> <u>tariff</u> rates.

Q. Is the Company proposing any changes to the existing rate structures within its rate schedules?

A. Yes. The Company is proposing a change to the rate structures for energy usage under Large General Service Schedule 21 and Extra Large General Service Schedule 25. The present rate structures for general service Schedules 21 and 25 both have a single rate for all energy usage for customers served under those schedules. The Company is proposing to add an additional energy rate block to each of those schedules. I will describe these proposed changes, as well as the rationale behind them, later in my testimony.

Q. Turning to Residential Service Schedule 1, could you please describe the present rate structure under this Schedule?

A. Yes. Residential Schedule 1 has a present customer / basic charge of $5.00 per month and three energy rate blocks: 0-600 kwhs, 601-1,300 kwhs and over 1,300 kwhs. The present base tariff rate for the first 600 kwhs per month is 4.522 cents per kwh, 5.261 cents for the next 700 kwhs and 6.167 cents for all kwhs over 1,300.

Q. How does the Company propose to spread the proposed general revenue increase of $17,482,000, or 14.3%, to Schedule 1?

A. The company proposes to increase the monthly customer charge from $5.00 to $5.50, or 10%, with the remaining revenue requirement recovered through a uniform 0.742 cents per kwh increase applied to all energy rates under the Schedule, as shown in column (e) on page 3.

Q. Why is the Company proposing to increase the monthly customer charge from $5.00 to $5.50 per month?

A. A significant portion of the proposed revenue increase reflected in this filing results from increases in fixed costs that do not vary with customer usage. These costs include additional investment in electric plant and increased operating costs that will increase or maintain the reliability of service to customers. Given the Company's increase in fixed costs reflected in this filing, as well as the overall proposed increase of 14.3% to Residential Schedule 1, the Company believes that the proposed 10% increase to the customer charge of $0.50 per month is reasonable.

Q. What is Puget Sound Energy's current residential customer charge?

A. It was recently increased to $5.75 per month as part of the Commission's Order No. 6 (approving the Settlement Agreement) in Docket No. UE-040641.

Q. What is the average monthly electric usage for a residential customer, and what is the affect of the proposed increase on a customer's bill?

A. The average monthly usage for a residential customer is approximately 1,000 kwhs. Based on the proposed increase, the average monthly increase would be $7.92, or 14.4%. The present monthly bill for 1,000 kwhs of usage is $55.09 and the proposed monthly bill would be $63.01.

Q. Turning to General Service Schedule 11, could you please describe the present rate structure and rates under that Schedule?

A. Yes. The present rate structure under the Schedule includes a monthly customer charge of $5.75, a single energy rate of 7.300 cents per kwh for all usage under the Schedule, and a demand charge of $3.50 per kw for all demand in excess of 20 kw per month. There is no charge for the first 20 kw of demand.

Q. How is the Company proposing to apply the proposed general revenue increase of $2,599,000, or 8.8%, to the rates under Schedule 11?

A. The Company is proposing that the customer charge be increased by $0.25, from $5.75 to $6.00 per month. No increase is proposed for the demand charge (over 20 kw). The remaining revenue increase proposed for the Schedule would be achieved by increasing the energy charge by 0.674 cents per kwh.

Q. You stated earlier that the Company is proposing to add an energy usage block under the rate structures for both Large General Service Schedule 21 and Extra Large General Service Schedule 25. Could you describe these proposed changes and the rationale behind them?

A. Yes. The Company is proposing to add an energy rate block to Schedule 21 for monthly usage in excess of 250,000 kwhs per month and a rate block to Schedule 25 for usage in excess of 500,000 kwhs per month. Both schedules will have a lower incremental energy rate for usage above these levels. The rate for usage above 250,000 kwhs under Schedule 21 is proposed to be the same as the Schedule 25 rate for usage below 500,000 kwhs, as shown in column (g) on page 3 of Exhibit No.__(BJH-4).

Approximately 3,400 customers take service under Schedule 21. Customers served under the Schedule can have a monthly demand anywhere from 50 kw up to 3,000 kw, which is the minimum level required for service under Schedule 25. Obviously, there is a wide range of customers served under Schedule 21, ranging from a relatively small retail establishment to a large manufacturing plant. Generally, larger-usage customers under the Schedule are less costly to serve than smaller-usage customers on a cost per kwh basis, as fixed costs are spread over a larger base of usage. Therefore, a lower incremental / average rate for service to larger use customers under a Schedule generally is supportable on a cost of service basis.

Additionally, the difference in the present rates under Schedules 21 and 25 is substantial. There are a number of large customers served under Schedule 21 that are similar in size and usage to smaller Schedule 25 customers. In fact, several of these large Schedule 21 customers have a higher load factor than several customers served under Schedule 25. However, they pay an energy rate under Schedule 21 that is presently 44% higher than what they would pay under Schedule 25. Further, as shown on page 2 of Exhibit No. __(BJH-4), the cost of service results show that the rates for Schedule 21 exceed the cost of service, and the rates for Schedule 25 are less than the cost of service. Therefore, the rates paid by large Schedule 21 customers are well above the cost of service and the rates paid by smaller Schedule 25 customers are well below the cost of service.

Q. Can large customers served under Schedule 21 take service under Schedule 25? If so, what is the effect of such a change on the customer and the Company?

A. Customers can switch from service under Schedule 21 to Schedule 25 if they meet the minimum peak demand requirement of a 3,000 kva under Schedule 25. Because of the present rate differential between the two Schedules, a customer switching from Schedule 21 to 25 can see a substantially lower annual energy bill under present rates, which represents a revenue/margin loss to the Company until it is eventually recovered as a result of a general rate change. Further, the present rate disparity between the two Schedules encourages customers that are close to qualifying for service under Schedule 25 (3,000 kva) to increase their peak demand, which is inconsistent with the goals of energy efficiency and demand-side management programs.

Q. Have any customers switched from Schedule 21 to 25 recently?

A. Yes. A large Schedule 21 customer recently qualified for service under Schedule 25, and was switched to Schedule 25 in February 2005. Based on this customer's 2004 electric usage, they will save $255,000 a year, or 27% of their prior annual bill, based on present rates between the two Schedules. Based on the proposed rates for the two Schedules, this differential would be reduced to $125,000.

Q. How many customers are served under Schedule 21 whose monthly usage exceeds the proposed energy block of 250,000 kwhs?

A. There are approximately 100 customers (out of 3,400), or less than 3% of customers served under the Schedule, whose monthly usage exceeds 250,000 kwhs at some time during the year. Approximately 15 of these 100 customers average more than 500,000 kwhs per month. These fifteen customers include industrial/manufacturing companies, hospitals, college campuses, etc.

Q. Have you examined how the proposed rates under Schedule 21 would affect the bills of customers served under the Schedule at various usage levels?

A. Yes. Page 4 of Exhibit No. __(BJH-4) shows the estimated change in customers' bills under the Schedule at various usage levels, assuming they have a 50% load factor. As shown in column (f), about 97% of the customers under the Schedule would see an increase between 10.3% and 10.7% under the proposed rates. About 2% of the customers (who use more than 250,000 but less than 500,000 kwhs per month) would see an increase between 3.1% and 10.3%, and about 15 customers (less than 1%) would see an increase of 3.1% or less based on their average usage exceeding 500,000 kwhs per month.

Q. Could you please describe all of the proposed (general) rate changes under Schedules 21 and 25?

A. Yes. As previously stated, the Company is proposing that the base tariff rate(s) be the same for usage over 250,000 kwhs under Schedule 21 and for usage under 500,000 kwhs under Schedule 25. This proposed rate is 4.494 cents per kwh, as shown in column (g) on page 3. As shown in column (e), the proposed base rate increase for the first 250,000 kwhs used per month under Schedule 21 is 0.578 cents per kwh, and a decrease of 0.332 cents per kwh for usage over 250,000 per month. The Company is also proposing that the present minimum demand charge be increased by $25 per month, from $225.00 to $250.00, and the demand charge for kw over 50 per month be increased by $0.25 per kw, from $2.75 to $3.00. These proposed changes result in the total proposed general revenue increase of $9.4 million, or 10.5%, to Schedule 21, as shown on line 3, page 1, of Exhibit No. __(BJH-4).

Regarding Schedule 25, as shown in column (e) on Page 3 of Exhibit No. __(BJH-4), the proposed base rate increase for the first 500,000 kwhs used per month under Schedule 25 is 1.110 cents per kwh, and the increase for kwh usage over 500,000 per month is 0.295 cents per kwh. The Company is also proposing that the present minimum demand charge be increased by $1,500 per month, from $7,500 to $9,000, and the demand charge for kva over 3,000 per month be increased by $0.50 per kva, from $2.25 to $2.75. These proposed changes result in the total proposed general revenue increase of $4.63 million, or 13.3%, to Schedule 25, as shown on line 4, page 1, of Exhibit No. __(BJH-4).

Q. Have you estimated the increase to individual Schedule 25 customers based on the proposed rates?

A. Yes. There are 20 customers served under Schedule 25. The proposed rates under that Schedule result in an increase ranging from a low of 9.6% to a high of 19.9%. As a result of the proposed two-block energy rate structure, lower energy users under the Schedule would see a higher percentage increase, while higher users would see a lower percentage increase. Again, the purpose of these rate design changes is to more closely align the rates to be paid by customers with similar usage and cost of service (large Schedule 21 and small Schedule 25 customers).

Q. Are these proposed rate structures for Schedules 21 and 25 presently effective for similar customers served by the Company in Idaho?

A. Yes. The Idaho Commission approved these rate structures effective September 2004.

Q. What changes does the Company propose to the rates under Pumping Schedule 31 to recover the proposed general revenue increase of $726,000, or 12.0%?

A. The proposed general increase applicable to Pumping Service Schedule 31 is spread on an equal cents per kwh basis to the present energy blocks under the Schedule. This results in a total general increase of 0.604 cents per kwh for all energy usage under the Schedule, which is shown in column (e) on Page 3 of Exhibit No.__(BJH-4).

Q. How is the Company proposing to spread the general revenue increase of $470,000, or 11.0%, applicable to street and area light schedules to the rates contained in those schedules (Schedules 41-48)?

A. The Company proposes to increase all present street and area light rates on an equal percentage basis (11.0%). The resulting (base tariff) rates are shown in the proposed tariffs for those Schedules, contained in Exhibit No. __(BJH-3).

Other Tariff Changes

Q. Are you proposing any other changes to the electric service tariffs?

A. Yes. Within Residential Service Schedule 1, the company is proposing to add language that makes it clear that a residence can have only one meter billed under the Schedule; any additional meters would be billed the appropriate general service schedule. Serving only one meter per residence under Schedule 1 has always been the company's practice – adding the proposed language under the Schedule merely provides additional clarity in the tariff.

Additionally, the company is proposing to add language under Extra Large General Service Schedule 25 that clarifies eligibility for service under the Schedule. The present tariff states that a customer must have a peak demand of 3,000 kva in order to qualify for service under the Schedule. The company is proposing to add language that states that a customer must <u>average</u> 3,000 kva over the most recent twelve-month period. For a new customer to be served under the Schedule, the Company must have reasonable assurance that the customer's peak demand will consistently exceed 3,000 kva. The company has consistently used these provisions in practice, and inclusion in the tariff will not affect any customer presently served under the Schedule.

Language is also proposed to be added under Schedule 25 that a customer served under the Schedule will not be penalized for the installation of demand-side management (DSM) measures. More specifically, if the installation of DSM measures causes the customer's peak demand to fall below an average of 3,000 kva per month, the customer will continue to be served under the Schedule. Again, this has been the company's practice where this situation has occurred in the past. Further, these provisions have existed in the corresponding Idaho tariff for many years. The specific language regarding these provisions is shown on the proposed tariff sheets in Exhibit No. __(BJH-3).

Lastly, the Company is proposing to implement a 1% per month late charge for unpaid bills past the next month's bill date (approximately thirty days). The proposed "late charge" provision is set forth in Sheet No. 70F (electric) and 170F (gas), as shown in Exhibit Nos. __(BJH-3) and __(BJH-4), respectively..

Q. Does the Company have a 1% per month late charge effective for service in its Idaho and Oregon jurisdictions?

A. Yes it does.

Q. Has the Company estimated the additional amount of revenue that would be collected from the implementation of the proposed late charge?

A. Yes. The Company estimated the additional revenue by applying the proposed late charge provision to all billings issued during 2004. The estimated additional late charge revenue based on 2004 billings is $775,000. The Company then allocated this amount between electric and natural gas service based on total revenue billed for each service during 2004. The result was estimated late charge revenue of $529,000 for electric service, which was deducted from the total revenue requirement to be spread to the electric service schedules, and $246,000 for natural gas service, which was deducted from the total revenue requirement to be spread to the Company's natural gas service schedules.

IV. PROPOSED NATURAL GAS REVENUE INCREASE

Q. Turning now to the Company's proposed natural gas increase, would you please explain what is contained in Exhibit No. __(BJH-5), entitled "Present Natural Gas Service Schedules"?

A. Yes. Exhibit No. __(BJH-5) is a copy of the present rates for the Company's natural gas general service tariffs as part of this filing.

Q. Please explain what is contained in Exhibit No. __(BJH-6)?

A. This Exhibit, entitled "Proposed Gas Rates", contains the proposed gas rates and schedules which are being filed with the Commission as a part of our revised tariff, WN U-29.

Q. Would you please describe what is contained in Exhibit No. __(BJH-7)?

A. Yes. Exhibit No. __(BJH-7) contains supplemental information regarding the spread of the proposed gas revenue increase to the Company's service schedules and the proposed rates within the schedules, which I will refer to later in my testimony.

<u>Revenue Normalization Adjustment</u>

Q. Could you please describe the "revenue normalization adjustment" applicable to natural gas sales?

A. Yes. The gas revenue normalization adjustment is similar to the electric adjustment and represents the difference between the Company's actual revenues during the 2004 test period and revenues based on normalizing and pro forma adjustments. The adjustment includes the repricing of pro forma sales and transportation volumes at present rates using pro forma sales volumes that have been adjusted for unbilled revenue, abnormal weather, and any material customer load or schedule changes. The rates used exclude: 1) temporary Gas Rate Adjustment Schedule 155, which reflects the approved amortization rate for deferred gas costs approved in the Company's last PGA filing, and 2) DSM rider adjustment Schedule 191.

Q: Does the Revenue Normalization Adjustment contain a component reflecting normalized gas costs?

A: Yes. Purchase gas costs are normalized using the gas costs approved by the Commission in Docket No. UG-041786, the Company's 2004 PGA filing, as set forth under Schedule 150. Those gas costs are then applied to the pro forma retail sales volumes so that there is a matching of revenues and gas costs.

The total net amount of the revenue normalization, which includes the purchase gas cost adjustment, is an increase of $3,758,000 on a net operating income basis, as shown in column (h) page 5 of Exhibit No. __(DMF-3). The majority of this adjustment is due to the general revenue increase that was effective November 2, 2004 (Docket No. UG-041515).

Summary of Natural Gas Rate Schedules and Tariffs

Q. Would you please review the Company's present rate schedules and the types of gas service offered under each?

A. Yes. The Company's present Schedules 101, 111, and 121 offer firm sales service. Schedule 101 generally applies to residential and small commercial customers who use less than 200 therms/month. Schedule 111 is generally for customers who consistently use over 200 therms/month and Schedule 121 is generally for customers who use over 10,000 therms/month and have a high annual load factor. Schedule 131 provides interruptible sales service to customers whose annual requirements exceed 250,000 therms. Schedule 146 provides transportation/distribution service for customer-owned gas for customers whose annual requirements exceed 250,000 therms. Schedule 148 is a banded-rate transportation tariff that allows for a negotiated service rate with large customers that have an economic alternative to taking distribution service from the company.

Q. The Company also has rate schedules 112, 122, and 132 on file with the Commission. Could you please explain what customers are eligible for service under these schedules?

A. Schedules 112, 122, and 132 are in place to provide service to customers who at one time were provided service under Transportation Service Schedule 146. The rates under these schedules are the same as those under Schedules 111, 121, and 131 respectively, except for the application of temporary Gas Rate Adjustment Schedule 155. Schedule 155 is a temporary rate adjustment used to amortize the deferred gas costs approved by the Commission in the prior PGA. Transportation service customers are analyzed individually to determine their appropriate share of deferred gas costs. If those customers switch back to sales service, the Company continues to analyze those customers individually, otherwise, those customers would receive amounts of gas costs deferrals which are not due them, thus the need for Schedules 112, 122, and 132. There are presently only 10 customers in total served under these Schedules.

Q. How many customers does the Company serve under each of its natural gas rate schedules?

A. As of December 2004, the Company provided service to the following number of customers under each of its schedules:

Schedule	Type of Customer	No. of Customers
General Service 101	Residential & Sm. Commercial	132,000
Lg. General Service 111/112	Comm. & Ind. - over 200 therms/mo.	2,200
Ex. Lg. Gen. Service 121/122	Comm. & Ind. - over 10,000 therms/mo.	41
Interruptible Service 131/132	Interruptible - over 250,000 therms/yr.	1
Transportation Service 146	Transportation of Customer-owned Gas	24
Banded-Rate Transport. 148	Transportation – Special Contract	5

Proposed Change in Allocation of Pipeline Demand Costs

Q. Is the Company proposing any changes to the present allocation of purchase gas costs by service schedule in this Case?

A. Yes. The Company is proposing to revise its present allocation of pipeline (fixed) contract demand costs in this filing. Pipeline demand costs are presently allocated to all sales service schedules based on 90% sales volumes and 10% peak demand. Interruptible sales are excluded from the 10% peak demand allocation. This methodology was approved by the Commission in 1992, based upon a Commission Staff proposal. However, the Commission approved a significantly different allocation of pipeline demand costs in 1994 in Docket No. UG-940814 (Washington Natural Gas methodology). The Company is proposing an allocation of these costs based on 60% sales volumes and 40% peak demand, which is nearly identical to the allocation of these costs approved by the Commission in the 1994 Docket. The proposed allocation of costs based on peak demand would again exclude Interruptible Sales Schedules 131 and 132, and would apply only to firm sales schedules.

Q. Why do you believe the proposed 60/40 allocation of these costs is more reasonable than the present 90/10 allocation?

A. These pipeline demand costs are based on the amount of pipeline capacity contracted for by the Company. This amount of pipeline capacity is based on the estimated amount of gas necessary to meet customer load requirements on a peak day. While a case can be made for allocating these costs by service schedule based entirely on peak demand, the Company believes that an allocation based on 60% sales volumes and 40% peak demand is reasonable.

Q. Why should Interruptible Sales Schedules 131 and 132 be excluded from the 40% allocation of these costs based on peak demand?

A. Interruptible sales volumes are presently excluded from the present 10% allocation of these costs based on peak demand. Customers served under interruptible sales schedules can be interrupted on a peak day. These customers understand and accept this provision as a condition of service under the schedule(s). As such, the Company does not contract for firm pipeline capacity to serve interruptible customers on a peak day.

The Company presently has only one customer served under its interruptible sales schedule. With the present allocation of pipeline demand costs, and interruptible sales receiving an allocation of 90% of those costs, there is essentially no financial/rate incentive for a customer to take interruptible service from the Company. The proposed 60/40 allocation of pipeline demand costs will create a financial/rate incentive for eligible customers to take interruptible service, which in the long-run benefits all customers.

Q. What is the rate effect by service schedule of the proposed 60/40 allocation methodology?

A. The resulting rate change by service schedule is as follows:

	Increase (Decrease) / therm
General Service Sch. 101	\$0.00106
Lge. General Service Sch. 111	\$0.00005
Lge. Svc. – High Load Factor Sch. 121	(\$0.01252)
Interruptible Service Sch. 131	(\$0.02397)

As shown, the proposed cost allocation change results in meaningful reduction to the rates under Interruptible Schedule 131, as well as Large/High Load Factor Service Schedule 121 (because of their high load factor), while the resulting increase in rates is approximately 0.1% for Schedule 101 and is negligible for Schedule 111.

Proposed Rate Spread

Q. How does the Company propose to spread the overall revenue increase of $2,943,000, or 1.8%, among its general service schedules?

A. The Company is proposing the following revenue/rate changes by rate schedule:

General Service Schedule 101	2.1%
Large General Service Schedule 111/112	0.8%
High Annual Load Factor – Lg. General Service Schedule 121/122	0.7%
Interruptible Sales Service Schedule 131/132	(3.2%)
Transportation Service Schedule 146	2.2%

This information is also shown on Page 1 of Exhibit No. __(BJH-7).

Q. Are the effects of the proposed change in the allocation of pipeline demand costs described earlier included in the overall proposed increases (decrease) by rate schedule?

A. Yes they are.

Q. Is the proposed increase for Transportation Schedule 146 comparable to the increase (decrease) for the other service schedules?

A. No. The proposed increase for Transportation Schedule 146 is not comparable to the proposed increases (decrease) for the other (sales) service schedules, as Schedule 146 revenue does not include an amount for the cost of gas or pipeline transportation, whereas the other sales schedules include those costs/revenue. (Transportation customers acquire their own gas and pipeline transportation.) Including a conservative level of 50.0 cents per therm for the cost of gas and pipeline transportation, the proposed increase to Schedule 146 rates represents an average increase of 0.2% in those customers' total gas bill, which is then expressed on a relatively comparable basis to the proposed increase (decrease) to the other (sales) service schedules, and the overall proposed increase of 1.8%.

Q. What rationale did the Company use in its proposed spread of the overall revenue increase to the various rate schedules?

A. The Company again utilized the results of the cost of service study, as sponsored by Company witness Knox, as a guide in developing the proposed rate spread. The proposed spread of the overall increase results in a relative rate of return for all schedules that is within 5% of unity (.95 - 1.05).

Page 2 of Exhibit No. __(BJH-7) shows the rates of return for each of the Company's gas schedules before and after application of the proposed increases. Column (d) shows the relative rates of return under present rates and column (f) shows the relative rates of return under proposed rates. The relative rates of return before and after application of the proposed increases by schedule are as follows:

	Before	After
Schedule 101:	0.97	0.98
Schedule 111:	1.11	1.05
Schedule 121:	1.10	1.05
Schedule 131:	1.95	1.05
Schedule 146:	1.15	1.05

With an overall proposed increase of 1.8%, the Company believed that this was an opportune time to move the rates of return for all schedules relatively close to unity.

Q. Is the proposed (60/40) allocation of pipeline demand costs described earlier, reflected in the Company's cost and service study and the relative rates of return in the table above.

A. Yes.

Proposed Rate Design

Q. Could you please explain what is shown on Page 3 of Exhibit No. __(BJH-7)?

A. Yes. Page 3 of Exhibit No. __(BJH-7) shows a comparison of the present and proposed rates within each of the Company's gas service schedules.

Q. Could you please explain the present rate design within each of the Company's gas service schedules?

A. Yes. General Service Schedule 101 generally applies to residential and small commercial customers who use less than 200 therms/month. The schedule contains a single rate per therm for all gas usage and a monthly customer/basic charge.

Large General Service Schedule 111 has a three-tier declining-block rate structure and is generally for customers who consistently use over 200 therms/month. The schedule consists of a monthly minimum charge plus a usage charge for the first 200 therms or less, and block rates for 201-1,000 therms/month and usage over 1,000 therms/month.

Extra Large General Service Schedule 121 has a five-tier declining-block rate structure with a monthly minimum charge plus a usage charge for the first 500 therms or less, and block rates for the next 500 therms, the next 9,000 therms, the next 15,000 therms, and usage over 25,000 therms/month. There is also an annual minimum requirement of 60,000 therms under the schedule and a minimum load factor requirement of approximately 58%.

Interruptible Sales Service Schedule 131 has a four-tier declining-block rate structure for the first 10,000 therms, the next 15,000 therms, the next 25,000 therms, and usage over 50,000 therms per month. The Schedule also has an annual minimum deficiency charge based on a usage requirement of 250,000 therms per year.

Transportation Service Schedule 146 contains a $200 per month customer charge and a five-tier decining-block rate structure for the first 20,000 therms, the next 30,000 therms, the next 250,000 therms, the next 200,000 therms, and usage over 500,000 therms per month. The Schedule also has an annual minimum deficiency charge based on a usage requirement of 250,000 therms per year.

Q. Is the Company proposing any changes to the present rate structures contained in its gas service schedules?

A. No, it is not.

Q. Where in you Exhibits do you show the present and proposed rates for the Company's natural gas service schedules?

A. Page 3 of Exhibit No. __(BJH-7) shows the present and proposed rates under each of the rate schedules, including all present rate adjustments (adders). Column (b) on that page shows the proposed changes to the rates contained in each of the schedules.

Q. You stated earlier in your testimony that the Company is proposing an overall increase of 2.1% to the rates of General Service Schedule 101. Is the Company proposing an increase to the present basic/customer charge of $5.50/month under the schedule?

A. No.

Q. What is the proposed increase to the rate per therm under Schedule 101 in

order to achieve the proposed revenue increase of 2.1%?

A. The proposed increase to the energy rate under the schedule is 1.969 cents per therm, as shown in column (b), page 3 of Exhibit No. __(BJH-7).

Q. What would be the increase in the typical residential customer's bill based on the Company's proposed increase for Schedule 101?

A. The increase for a typical residential customer using 75 therms of gas per month would be $1.48 per month, or an increase from $74.77 per month to $76.25 per month (including all present rate adjustments).

Q. Could you please explain the proposed changes in the rates for Large and Extra Large General Service Schedules 111 and 121?

A. The present rates for Schedules 101, 111, and 121 provide a clear distinction for customer placement: customers who use less than 200 therms/month should be placed on Schedule 101, customers who use between 200 and 10,000 therms per month should be placed on Schedule 111, and only those customers who generally use over 10,000 therms per month should be placed on Schedule 121. Not only do the rates provide a guide for customer schedule placement, they provide a reasonable classification of customers for analyzing the costs of providing service.

The Company's proposed rates for Schedules 111 and 121 will maintain the rate structure within the schedules and continue to provide a guide for appropriate schedule placement for customers and a reasonable classification for cost analysis. The proposed increase to the minimum charge for Schedule 111 (for 200 therms or less) of $3.94 per month was derived by multiplying the proposed increase to the Schedule 101 rate per therm of 1.969 cents by 200 therms. This methodology maintains the present relationship between the Schedules, and will minimize customer shifting. The remaining proposed revenue increase for Schedule 111 was then spread on an equal cents per therm basis, 0.507 cents, to the remaining two rate blocks under the Schedule, resulting in an overall revenue increase of 0.8% for the Schedule.

For Schedule 121, the increase in the minimum charge (for 500 therms or less) of $9.85, was derived by multiplying the proposed increase in the Schedule 101 rate per therm by 500. The second and third block rates were then increased by an amount equal to the increase in the corresponding block rates under Schedule 111. Again, this methodology maintains the present relationship between the Schedules and will minimize customer shifting. The proposed increase to the fourth block under the Schedule is 0.721 cents per therm, and no increase is proposed for the fifth block rate. The block rate increases described above result in the overall proposed revenue increase of 0.7% for Schedule 121.

Q. Why is the Company proposing no increase be applied to the last (fifth) block under Schedule 121?

A. The present rate differential under the fourth and fifth blocks is less than 1 cent per therm. By not applying an increase the fifth block, the differential between the two block rates is approximately 1.7 cents per therm, thus providing a more reasonable and meaningful rate differential between the two block rates.

Q. How is the company proposing to spread the proposed <u>decrease</u> of 3.2% to the rates under Interruptible Schedule 131?

A. The company proposes the following decrease per therm to the rates under Interruptible Schedule 131: Block 1 – (2.1) cents, Block 2 – (2.2) cents, Block 3 – (2.3) cents, Block 4 – (3.2) cents. Similar to the proposal for Schedule 121, the larger decrease applied to the last block will provide a more reasonable rate differential among the blocks in the Schedule. Again, the overall proposed decrease for Interruptible Schedule 131 relates primarily to the proposed reallocation of pipeline demand costs discussed earlier. As shown in the table on page 25 of my testimony, the proposed allocation results in a reduction in cost assignment to the Schedule of approximately 2.4 cents per therm. As shown in the (relative rate of return) table on page 27, the proposed decrease of 3.2% to Schedule 131 results in a rate of return for the Schedule relatively close to the overall proposed rate of return.

Q. How is the company proposing to spread the overall proposed increase of 2.2% to the rates within Transportation Schedule 146?

A. The Company is proposing to spread the increase on a uniform percentage basis to each of the present five block rates under the Schedule. Therefore, all customers served under the Schedule will receive a similar increase, on a percentage basis. The proposed increase to each of the block rates, as well as the present and proposed rates are shown at the bottom of page 3 of Exhibit No. __(BJH-7).

<u>**Gas Management Transition Adjustment**</u>

Q. Would you briefly describe the Transition Plan to transfer the Company's gas procurement functions from Avista Energy, under the prior Gas Benchmark Mechanism, back to the utility?

A. Yes. In the Washington Commission's Seventh Supplemental Order, Docket No. UG-021584, the Commission approved the Company's Transition Plan to return Avista Utilities' natural gas procurement, transportation and storage management functions from its subsidiary, Avista Energy, back to Avista Utilities. Avista Utilities has taken the steps necessary to bring the gas procurement functions back within the utility, such as hiring and training of employees, appropriate notifications of pipeline, storage and third party suppliers, increasing the credit line at the utility, and development and documentation of internal administrative procedures. As of April 1, 2005, all natural gas procurement, transportation and storage management functions will reside with the Utility.

Q. Is the Company including a pro forma adjustment in this case related to the additional costs of returning the natural gas procurement functions to the Utility?

A. Yes. Included in the Company's pro forma adjustments is Washington's allocated portion of the estimated additional costs for loaded labor and associated administrative support costs for four additional employees, including a Director of Natural Gas Resources. As of the date of this filing, three employees have been hired, including the Director, and the remaining one will be hired by mid-2005. The effect of this adjustment reduces Washington net operating income by $125,000. This adjustment is shown in column (PF5), page 8 of Exhibit No. __(DMF-8).

V. ELECTRIC AND NATURAL GAS ENERGY EFFICIENCY PRUDENCE REQUEST

Q. What is the Company's request in this case regarding energy efficiency?

A. When the Commission approved the Company's energy efficiency programs in 1995 (in Docket Nos. UE-941377 and UG-941378, reiterated in Docket No. UE-961309), Avista committed to demonstrating the prudence of program expenditures in future general rate cases. In the Company's last general electric rate case (Docket No. UE-011514), the Commission found prudent Avista's electric DSM expenditures for the period between January 1, 1999 and August 31, 2001; in Docket No. UG-991607 the Commission found Avista's gas DSM expenditures prudent between January 1, 1995 and December 31, 1998. At this time, the Company respectfully requests that the Commission issue a finding that electric energy efficiency expenditures from September 1, 2001 through December 31, 2003 and natural gas energy efficiency expenditures from January 1, 1999 through December 31, 2003 were prudently incurred.

Q. Would you please summarize the Company's energy efficiency-related programs?

A. Yes. As the Commission is aware, the Company's tariff riders under Schedules 91 (electric) and 191 (gas) were the first non-bypassable distribution charges in the United States to fund energy efficiency. The electric energy efficiency tariff rider is an amount equal to approximately 1.50% of retail base rates to all rate classes. The natural gas tariff rider is currently a 0.96% distribution surcharge and is scheduled to return to a 0.50% surcharge on January 1, 2006. The natural gas DSM tariff rider was reinstated in 2001 after its initial implementation from 1995 through 1997.

The tariff rider and the corresponding energy efficiency programs have been very successful. During the 28 months of electric DSM program activity for which the Company is requesting a finding of prudence, over <u>95 million</u> kWh of energy savings were obtained. During the five years of natural gas DSM program activity for which the Company is requesting a finding of prudence, over <u>2.2 million</u> therms of energy savings were obtained. Page 1 of Exhibit

No. __(BJH-8) details the energy savings by regular and limited-income portfolios for both electric and natural gas DSM programs.

Q. How are the energy efficiency programs organized?

A. The Company's approach focuses on educating the customer about the benefits of energy efficiency, providing a third party review, and outlining potential savings of the project. The Company's commercial/industrial programs provide assistance to any energy efficiency measure that demonstrates a quantifiable energy saving kWh or therm. Energy efficiency measures that are most commonly implemented include lighting, heating and ventilation equipment, air conditioning, variable frequency drives, insulation and premium efficiency motors. Many types of industrial process improvements that are unique to a customers site (e.g. dry kiln fans) as well as compressed air, refrigeration, and controls are also incorporated into the program mix.

Rebates are also offered for a variety of residential measures. The measures include high efficiency electric furnace and water heaters, high efficiency natural gas furnace and water heaters, heat pumps, insulation for both electric and natural gas heated homes and electric to gas conversions. The Company contracts with local Community Action Agencies to assist Limited Income customers with implementation of many of the same measures from the Residential Portfolio, as well as any additional health and human safety improvements necessary for the home. The Company is also a member of the Northwest Energy Efficiency Alliance (NEEA) and participates in the regional market transformation programs that are developed from that organization.

Q. What customer classes can benefit from these programs?

A. The Company's programs are delivered across a full customer spectrum. Virtually all customers have had the opportunity to participate and have directly benefited from the program offerings. All customers have indirectly benefited through enhanced cost-efficiencies as a result of this portfolio.

For example, Avista has worked in cooperation with governmental entities such as Washington State University, the Spokane Community Colleges, School District 81 and the Washington Department of General Administration and others to secure cost-effective energy savings that directly benefit not only those specific parties, but also indirectly benefit the community at large. Residential customers have received direct benefits through a broad array of well-received electric and natural gas energy-efficiency programs.

Q. Has there been ongoing review of the Company's programs?

A. Yes. The Company has regularly convened a stakeholders forum known as the External Energy Efficiency Board. These meetings have included customer representatives, Commission staff members, and individuals from the environmental communities. These stakeholder meetings have reviewed each program as well as the underlying cost-effectiveness tests and results.

Q. Does the Tariff Rider have any impact on the normalized level of Company earnings for its Washington jurisdiction?

A. No. The revenue generated by the Tariff Rider has a matching expense associated with it. The bottom line, or net operating income impact is zero, so there is no earnings impact. The actual management of the program disbursements is done through a balance sheet account.

Q. Have the Company's DSM programs been cost-effective?

A. Yes. The programs have been cost-effective from both a Total Resource Cost (TRC) and Utility Cost Test (UCT) perspective. Page 2 of Exhibit No.__(BJH-8) shows that the TRC benefit-to-cost ratio for the overall electric DSM program portfolio is cost-effective, with a net TRC benefit to customers of over $2 million. The UCT benefit to cost ratio is cost-effective at 2.47 with a net UCT benefit of over $15 million. The levelized TRC and UCT cost is 3.6 cents and 1.3 cents per kWh, respectively, for a weighted average measure life of 16 years. The comparable electric avoided cost is 4.8 cents per kWh. The electric DSM programs were also cost-effective under the Participant Test.

Page 3 Exhibit No. __(BJH-8) illustrates that the natural gas DSM program portfolio is also cost-effective under both the TRC and UCT tests. The TRC of gas DSM programs is cost-effective with a net benefit of over $3.7 million. The UCT benefit to cost ratio is cost-effective with a net benefit of over $9 million. The levelized TRC and UCT cost is 55 cents and 21 cents per therm, respectively, for a weighted average measure life of 23 years. The comparable levelized avoided cost per annual therm is 59 cents and 68 per winter therm. The natural gas DSM portfolio passes the Participant Test.

Q. Please summarize the Company's conclusions.

A. The Company's expenditure of tariff rider revenue has been reasonable and prudent. During the time period that the Company is requesting a finding of prudence, a portfolio of programs covering all customer classes have been offered with a total savings of over 95 million annual kWhs and 2.2 million therms. A 16-year levelized utility cost per saved kilowatt hour of 1.3 cents per kWh has been achieved. The levelized avoided costs during this similar period has been 4.8 cents per kWh. The 23 year levelized utility cost per saved therm has averaged 21.2 cents per therm. The terms of the levelized costs are consistent with the weighted average measure life of the two portfolios.

From a qualitative perspective, the tariff rider and programs have also been very successful. Participating customers have benefited through lower bills. Non-participating customers have benefited from the Company having acquired low cost resources as well as maintaining the energy efficiency message and infrastructure for the benefit of our service territory.

Q. Does that complete your pre-filed direct testimony?

A. Yes, it does.