Exhibit No. ___(PDE-1T)

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-10_____

DOCKET NO. UG-10_____

DIRECT TESTIMONY OF

PATRICK D. EHRBAR

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

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

A. My name is Patrick D. Ehrbar 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 Rates and Tariffs.

Q. Would you briefly describe your duties?

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

Q. Would you briefly describe your educational background and professional experience?

A. I am a 1995 graduate of Gonzaga University with a Bachelors degree in Business Administration. In 1997 I graduated from Gonzaga University with a Masters degree in Business Administration. I started with Avista in April 1997 as a Resource Management Analyst in the Company's DSM department. Later, I became a Program Manager, responsible for energy efficiency program offerings for the Company's educational and governmental customers. In 2000, I was selected to be one of the Company's key Account Executives. In this role I was responsible for, among other things, being the primary point of contact for numerous commercial and industrial customers, as well as being the channel through which the Company offered its site specific energy efficiency programs.

I joined the State and Federal Regulation Department as a Senior Regulatory Analyst in 2007. Responsibilities in this role included being the discovery coordinator for

the Company's rate cases and lead coordinator for the Natural Gas Decoupling Mechanism pilot program and resulting reporting and analysis. In November 2009, I was promoted to my current role.

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 $55,298,000, or 13.8%, among the Company's electric general service schedules. This represents an overall increase of 13.4% in billed revenues/ rates, as explained below. With regard to natural gas service, I will describe the spread of the proposed annual revenue increase of $8,489,000, or 5.4%[1], among the Company's natural gas service schedules. My testimony will also describe the changes to the rates within the Company's electric and natural gas service schedules. Finally, I will respond to the Commission's recent order regarding whether the Company's natural gas decoupling mechanism should be applicable to natural gas rate schedules other than Schedule 101, per paragraph 303 of the Commission's Order No. 10 in Docket UG-090135.

Q. Are you sponsoring any Exhibits that accompany your testimony?

A. Yes. I am sponsoring Exhibit Nos.___(PDE-2), ___(PDE-3), and ___(PDE-4) related to the proposed electric increase, and Exhibit Nos.___(PDE-5), ___(PDE-6), and ___(PDE-7) related to the proposed natural gas increase. These were prepared by me or under my supervision.

[1] The increase in natural gas base revenue is 5.4%, the increase in billed revenue (including all rate adjustments) is 6.0%.

Table of Contents Page

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 total increase by rate schedule?

A. The proposed electric increase is $55,298,000, or 13.8% over present base tariff rates in effect. The proposed general increase over present billing rates, including all other rate adjustments (DSM and Residential Exchange), is 13.4%. The proposed general increase of $55,298,000 has been spread by rate schedule using the Company's cost of service study results, as discussed by Company witness Ms. Knox, as a guide. The proposed percentage increase by rate schedule is as follows:

Table 1 - Proposed % Electric Increase by Schedule

Rate Schedule	General Increase
Residential Schedule 1	14.8%
General Service Schedule 11	12.4%
Large General Service Schedule 21	13.3%
Extra Large General Service Schedule 25	12.6%
Pumping Service Schedule 31	14.8%
Street & Area Lights Schedules	13.8%
Overall	13.8%

This information is shown in detail on page 1, of Exhibit No.___(PDE-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 $10.62 per month, or a 14.8% increase in their electric bill. As part of that increase, the Company is proposing that the basic/customer charge be increased from $6.00 to $10.00 per month. The present bill for 1,000 kWhs is $71.79 compared to the proposed level of $82.41, including all rate adjustments.

Q. Why is the Company proposing an increase of this magnitude in the customer/basic charge?

A. A significant portion of the Company's costs are fixed and do not vary with customer usage. These costs include distribution plant and operating costs to provide reliable service to customers. Given the large disparity between the level of fixed customer costs and the present level of the basic charge, the Company believes that it is appropriate to recover a more reasonable level of these fixed customer costs through the basic charge. Section V of my testimony provides further details on our proposal.

Q. Is the Company proposing any changes to the present rate structures within its electric service schedules?

A. No. The Company is not proposing any changes to the present rate structures within its electric schedules.

Q. Where 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.___(PDE-4).

Proposed Natural Gas Increase

Q. How is the Company proposing to spread the overall natural gas increase of $8,489,000, or 5.4% by service schedule?

A. The Company is proposing the following base revenue/rate changes by rate schedule[2]:

Table 2 - Proposed % Natural Gas Increase by Schedule

Rate Schedule	General Increase
General Service Schedule 101	6.1%
Large General Service Schedule 111	3.3%
Ex. Lg. General Service Schedule 121	3.3%
Interruptible Sales Service Schedule 131	2.8%
Transportation Service Schedule 146	11.5%
Overall	**5.4%**

This information is also shown on page 1 of Exhibit No.___(PDE-7). The Company utilized the results of the natural gas cost of service study, sponsored by Witness Knox, as a guide in spreading the overall revenue increase to its natural gas service

[2] For Schedule 146, including a conservative level of 40.0 cents per therm for the cost of gas and pipeline transportation, the proposed increase to Schedule 146 rates represents an average increase of 1.74% in those customers' total gas bill.

schedules.

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 69 therms of gas per month would be $4.00 per month, or 6.8% A bill for 69 therms per month would increase from the present level of $58.79 to a proposed level of $62.79, including all present rate adjustments. As part of this increase, the Company is proposing an increase in the monthly customer charge of $4.00 per month, from $6.00 to $10.00, to recover a more reasonable level of fixed customer costs.

III. PROPOSED ELECTRIC REVENUE INCREASE

Summary of Electric Rate Schedules and Tariffs

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

A. Yes. Exhibit No.___(PDE-2) contains a copy of the Company's present electric tariffs/service schedules.

Q. Could you please describe what is contained in Exhibit No.___(PDE-3)?

A. Yes. Exhibit No.___(PDE-3) contains the proposed electric tariff sheets incorporating the proposed changes included in this filing.

Q. What is contained in Exhibit No._(PDE-4)?

A. Exhibit No.___(PDE-4) contains information regarding the proposed spread of the electric revenue increase among the service schedules and the proposed changes to the rates within the schedules. Page 1 shows the proposed general revenue and percentage increase by rate schedule compared to the present revenue under base tariff and billing

rates. Page 2 shows the rates of return and the relative rates of return for each of the schedules before and after application of the proposed general increase. Page 3 shows the present 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 will be referred to later in my testimony.

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 47-48. 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 Residential Exchange rate credit.

The following table shows the type and number of customers served in Washington (as of December 2009) under each of the service schedules:

Table 3 - Customers by Service Schedule

	No. of Customers
Residential Schedule 1	200,902
General Service Schedule 11	27,272
Large General Service Schedule 21	3,352
Extra Large General Service Schedule 25	22
Pumping Service Schedule 31	2,336

Proposed Electric Rate Spread

Q. How does the Company propose to spread the total general revenue increase request of $55,298,000 among its various rate schedules?

A. The Company is proposing that the overall requested revenue increase be spread on the following basis:

Table 4 - Proposed % Electric Increase by Schedule

Rate Schedule	General Increase
Residential Schedule 1	14.8%
General Service Schedule 11	12.4%
Large General Service Schedule 21	13.3%
Extra Large General Service Schedule 25	12.6%
Pumping Service Schedule 31	14.8%
Street & Area Lights Schedules	13.8%
Overall	13.8%

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

Q. What rationale did the Company use in developing the proposed general increase by rate schedule?

A. The Company used the results of the cost of service study (sponsored by Ms. Knox) as a guide to spread the general increase. The spread of the proposed increase generally results in the rates of return for the various service schedules moving approximately one-third closer to the overall rate of return (unity). The table below shows the relative rates of return (schedule rate of return divided by overall rate of return) before and after application of the proposed general increase, as well as the relative rate of return based on the application of the general increase on a uniform percentage basis (13.8%) to all rate schedules:

Table 5 -Present & Proposed Relative Rates of Return

Rate Schedule	Present Relative ROR	Proposed Relative ROR	Equal % Relative ROR
Residential Schedule 1	0.55	0.70	0.67
General Service Schedule 11	2.05	1.70	1.75
Large General Service Schedule 21	1.57	1.38	1.40
Extra Large General Service Schedule 25	0.73	0.82	0.86
Pumping Service Schedule 31	0.83	0.88	0.86
Street & Area Lights Schedules	1.86	1.52	1.52
Overall	**1.00**	**1.00**	**1.00**

As shown, for those schedules where the present rates are substantially above or below the cost of service, the proposed increase generally results in a reasonable movement toward unity (1.00).

Q. Looking at the results in the table above, it appears that the relative rates of return aren't substantially different under the Company's proposed rate spread compared to a uniform percentage application. Why isn't the Company just proposing to spread the general increase on a uniform percentage basis to the rate schedules?

A. As explained by Ms. Knox, Avista recently completed a new load study, and incorporated the results of that study into its cost of service study. In addition, Ms. Knox also explains a change to the peak credit methodology for demand allocation. While we believe it is reasonable and appropriate to use the cost of service study results as the basis for rate spread, we have tempered the amount of movement toward unity proposed in this case due primarily to the overall level of the proposed increase. Our proposal represents approximately a one-third movement toward unity, and slightly greater movement toward unity would than occur with the application of a uniform percentage increase across rate

schedules. The Company would plan to propose additional movement toward unity in future proceedings.

Proposed Rate Design

Q. Where in your Exhibit 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.___(PDE-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 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 billing rates and column (g) shows the proposed base tariff rates.

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

A. No, it is not.

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 or basic charge of $6.00 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 6.103 cents per kWh, 7.101 cents per kWh for the next 700 kWhs and 8.324 cents for all kWhs over 1,300.

Q. How does the Company propose to spread the proposed general revenue increase of $26,160,000 to Schedule 1?

A. The Company proposes to increase the monthly customer charge from $6.00 to $10.00. The proposed increase to the energy rate for the first block is 0.621 cents/kWh, 0.723 cents per kWh for the second block and 0.846 cents per kWh for the tail-block. The proposed rates for the three block rates reflect a uniform percentage increase of 10.2%.

Q. Why is the Company proposing to increase the monthly customer charge from $6.00 to $10.00 per month?

A. A substantial portion of the Company's costs are fixed and do not vary with the amount of energy used by customers. As reflected in this filing, the cost of operating and maintaining our electric system is increasing. The Company believes it is important that rates better reflect these increasing costs to serve customers. Later in my testimony I will provide greater detail as to why the Company believes the monthly customer charge should increase by $4.00 per month.

Q. What is the average monthly electric usage for a residential customer, and what is the effect 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 $10.62, or 14.8%. The present monthly bill for 1,000 kWhs of usage is $71.79 and the proposed monthly bill would be $82.41, including all rate adjustments.

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 $6.75, an energy rate of 9.638 cents per kWh for all usage up to 3,650 kWhs per month, and an energy rate of 9.023 cents per kWh for usage over 3,650 kWhs per month. There is also a demand charge of $4.25 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 $5,230,000 to the rates under Schedule 11?

A. The Company is proposing that the customer charge be increased by $3.25, from $6.75 to $10.00 per month. As with the proposed increase to the Schedule 1 basic charge, this proposal is intended to better align recovery of fixed costs on Schedule 11 through the basic charge. In addition, the Company is proposing that the demand charge (over 20 kW) be increased $0.75 per kW, from $4.25 to $5.00. This represents a 17.6% increase, which is greater than the overall increase to this rate schedule. The remaining revenue increase for the schedule is proposed to be recovered through a uniform percentage increase of approximately 10.4% applied to the two (block) energy rates. The increase in the first block rate is 0.998 cents per kWh, and 0.932 cents per kWh for the second block rate.

Q. Why is the Company proposing a higher percentage increase to the demand charge as compared to the energy charges?

A. The Company believes that it is important to increase the demand charge in this case for Schedule 11, as well as for Schedules 21 and 25, by a percentage greater than that applied to the energy rates. If demand charges are not increased <u>at least</u> proportionately with energy charges, customers who have a poor load factor (high peak

demand compared to average energy use) would see a lower percentage increase in their bill than a comparable customer with a good load factor (low peak demand compared to average energy use). This result would not send the appropriate price signal to commercial and industrial customers, nor would it reflect the fact that the Company's demand charges are well below the costs associated with meeting customers' peak demand.

The Company's transmission and distribution system is constructed to meet the collective peak demand of its customers. Additionally, the Company must have adequate resources available to meet peak demand. If customers reduce their peak demand, it will reduce the need for additional investment in these facilities and resources. Customers need to receive the proper price signal to encourage a reduction in their peak demand, i.e., higher demand charges.

Q. How does the level of demand costs from the Company's cost of service study compare to the present demand charges?

A. The system allocated demand cost from the cost of service study is approximately $17 per kilowatt (kW) month[3]. The Company's present monthly demand charges range from $3.50-$4.25/kW, depending on service schedule. While the exact level of costs classified as demand-related can be debated, clearly the level of demand charges are well below demand-related costs.

Q. Turning to Large General Service Schedule 21, would you please describe the present rate structure under that schedule and how the Company is proposing to apply the increase of $16,105,000 to the rates within the schedule?

A. Yes. Large General Service Schedule 21 consists of a minimum monthly charge of $300.00 for the first 50 kW or less, a demand charge of $4.00 per kW for

[3] Exhibit No. ___(TLK-4), page 3, line 28

monthly demand in excess of 50 kW, and two energy block rates: 6.284 cents per kWh for the first 250,000 kWhs per month, and 5.614 cents per kWh for all usage in excess of 250,000 kWhs.

The Company is proposing that the present minimum demand charge (for the first 50 kW or less) be increased by $50 per month, from $300.00 to $350.00, and the demand charge for kW over 50 per month be increased by $0.75 per kW, from $4.00 to $4.75, for reasons provided previously in my testimony. The remaining revenue increase for the schedule is proposed to be recovered through a uniform percentage increase of approximately 12.3% applied to the two energy block rates. The proposed increase for the first 250,000 kWhs used per month under the schedule is 0.773 cents per kWh, and an increase of 0.688 cents per kWh for usage over 250,000 kWhs per month.

Q. Turning to Extra Large General Service Schedule 25, would you please describe the present rate structure under that schedule and how the Company is proposing to apply the increase of $5,645,000 to the rates within the schedule?

A. Yes. Extra Large General Service Schedule 25 consists of a minimum monthly charge of $11,000.00 for the first 3,000 kVa or less, a demand charge of $3.50 per kVa for monthly demand in excess of 3,000 kVa, and three energy block rates: 4.928 cents per kWh for the first 500,000 kWhs per month, 4.433 cents per kWh for the next 5.5 million kWhs and 4.156 cents per kWh for all usage in excess of 6 million kWhs.

The Company is proposing that the present minimum demand charge under the schedule be increased by $1,500 per month, from $11,000 to $12,500, and the demand charge for kVa over 3,000 per month be increased by $0.50 per kVa, from $3.50 to $4.00. The remaining revenue increase for the schedule is proposed to be recovered through a

uniform percentage increase of approximately 12.1% applied to the three energy block rates. The proposed energy rate increase for the first 500,000 kWhs used per month is 0.596 cents per kWh, 0.536 cents per kWh for the next 5.5 million, and 0.502 cents per kWh for all usage over 6 million kWhs per month.

Q. What changes is the Company proposing to the rates under Pumping Schedule 31 to recover the proposed general revenue increase of $1,347,000?

A. The Company is proposing that the customer charge be increased by $1.00, from $6.75 to $7.75 per month, with the remaining revenue increase spread on a uniform percentage increase of 14.8% to the two energy rate blocks under the schedule. The proposed increase in the first block rate is 1.203 cents per kWh and the increase in the second block rate is 0.858 cents per kWh.

Q. How is the Company proposing to spread the proposed revenue increase of $811,000 applicable to Street and Area Light schedules, to the rates contained in those schedules (Schedules 41-48)?

A. The Company proposes to increase present street and area light (base) rates on a uniform percentage basis. The proposed increase for all lighting rates is 13.8%. The (base tariff) rates are shown in the tariffs for those schedules, contained in Exhibit No.___(PDE-3).

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

A. Yes. The Company is proposing to add language under Extra Large General Service Schedule 25 that would require a customer to execute a special contract for service of a new incremental load requirement of 25 MVA or greater. Specifically,

under the "Special Terms and Conditions" section of the tariff, the proposed language states:

> "A new or existing customer with an incremental electric demand requirement of 25,000 kVa or greater must execute a special contract for service, wherein the rates, terms and conditions for service may be different than those set forth under this schedule. The special contract will be subject to approval by the Washington Utilities and Transportation Commission (WUTC), and if the Company and the customer cannot agree on the rates, terms and conditions of service, the matter will be brought before the WUTC for resolution."

Q. What is the Company's rationale for this proposed provision?

A. The incremental cost associated with serving a new load of 25 megawatts or more could be substantial. Under the present Schedule 25 tariff, there is no provision limiting service at the rates set forth under this schedule. A customer with a new load requirement of 25, 50, or even 100 megawatts could request, and perhaps demand, service at Schedule 25 rates. The proposed provision would allow the Company and the Commission to consider the incremental costs required to provide the requested service.

As an example, if a new large load customer of 50 aMW were to request service from Avista, it would require the Company to acquire new long-term firm resources earlier than otherwise planned. The cost of new resources, whether they be combined cycle gas fired or wind generation, or both, range from approximately 7 cents to 11 cents per kWh. If we were to use 8 cents per kWh for the new resource, just for illustrative purposes, and Avista were to sell the 50 aMW to the customer under our proposed Schedule 25 rates (and without the possibility of a special contract), it would result in an incremental cost to other

customers of approximately $11.4 million[4], or an approximate 1.6% increase (system) in rates to all other customers.

Q. Does the Company have a similar provision in its Idaho tariff?

A. Yes, however, the provision in the Idaho Schedule 25 tariff states that customers whose total demand requirement exceeds 25,000 kVa may be served under a special contract. This provision has been in effect in Idaho since 1992. The only customer the Company serves in Idaho that exceeds this level is Clearwater Paper.

Q. Why isn't the Company proposing specific service rates or a banded-rate associated with this incremental load provision?

A. The rates for service to an incremental load of this size should consider all of the specific load characteristics unique to that customer/load that could have a substantial effect on the cost of service. These factors would include estimated energy usage and peak demand by month, day and hour, potential interruptibility, and distribution facility requirements, etc.

Q. Even though there are no specific rates associated with the proposed provision, could the provision itself be considered "unduly discriminatory" when the Company is already serving customers whose load requirements exceed 25 megawatts (25,000 kVa)?

A. No. The provision states that, "the rates for service may be different than those set forth under this Schedule". The provision does not state that the rates will be different. If the Company were to be presented with a new large load over 25,000 kVa,

[4] Using 50 aMW at a 90% load factor equates to approximately 438,000,000 kWhs. Using the average Schedule 25 rate of $0.054 (including demand), versus an $0.08 market example, you get the following: [438,000,000*(0.08-0.054) = $11.4 millon]

there would be opportunity to determine whether the characteristics of the new load warrant service rates different than those set forth under Schedule 25. Any special contract proposed under this provision would be subject to Commission review to determine if the rates for service are fair, just, reasonable and sufficient, and are not unduly discriminatory.

IV. PROPOSED NATURAL GAS REVENUE INCREASE

Q. Can you please explain what is contained in Exhibit No.___(PDE-5)?

A. Yes. Exhibit No.___(PDE-5) contains a copy of the Company's present natural gas tariffs presently on file with the Commission.

Q. Please describe what is contained in Exhibit No.___(PDE-6)?

A. Exhibit No.___(PDE-6) contains the proposed natural gas tariff sheets incorporating the proposed changes included in this filing.

Q. Please explain what is contained in Exhibit No.___(PDE-7)?

A. Exhibit No.___(PDE-7) contains information regarding the proposed spread of the natural gas revenue increase among the service schedules and the proposed changes to the rates within the schedules. Page 1 shows the proposed general revenue and percentage increase by rate schedule. Page 2 shows the rates of return and the relative rates of return for each of the schedules before and after the proposed increases. Page 3 shows the present 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 will be referred to later in my testimony.

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 which 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. Because of their size, 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 gas costs deferrals which are not due them, thus the need for Schedules 112, 122 and 132. There are presently only ten customers served under these schedules.

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

A. As of December 2009, the Company provided service to the following number of customers under each of its schedules:

Table 6 - Customers by Service Schedule

	No. of Customers
General Service Schedule 101	144,363
Large General Service Schedule 111	2,305
Ex. Lg. General Service Schedule 121	31
Interruptible Sales Service Schedule 131	1
Transportation Service Schedule 146	34

Proposed Rate Spread

Q. How does the Company propose to spread the overall revenue increase of $8,489,000, or 5.4%, among its natural gas general service schedules?

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

Table 7 - Proposed % Natural Gas Increase by Schedule

Rate Schedule	**General Increase**
General Service Schedule 101	6.1%
Large General Service Schedule 111	3.3%
Ex. Lg. General Service Schedule 121	3.3%
Interruptible Sales Service Schedule 131	2.8%
Transportation Service Schedule 146	11.5%
Overall	**5.4%**

Q. Is the proposed percentage increase for Transportation Schedule 146

comparable to the increase for the other service schedules?

A. No. The proposed percentage increase for Transportation Schedule 146 is not comparable to the proposed increases 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 these costs/revenue. Transportation customers acquire their own gas and pipeline transportation. Including a conservative level of 40.0 cents per therm for the cost of gas and pipeline transportation, the proposed increase to Schedule 146 rates represents an average increase of 1.74% in those customers' total gas bill.

Q. What information did the Company use to develop the proposed spread of the overall increase to the various rate schedules?

A. The Company utilized the results of the cost of service study, as sponsored by Ms. Knox, as a guide in developing the proposed rate spread. As explained by Ms. Knox, this study was just completed and the relative rates of return before and after application of the proposed increases by schedule are as follows:

Table 8 -Present & Proposed Relative Rates of Return

	Present Relative ROR	Proposed Relative ROR
General Service Schedule 101	0.94	0.98
Large General Service Schedule 111	1.20	1.08
Ex. Lg. General Service Schedule 121	1.08	1.03
Interruptible Sales Service Schedule 131	0.98	1.00
Transportation Service Schedule 146	1.15	1.06
Overall	**1.00**	**1.00**

Page 2 of Exhibit No.___(PDE-7) shows this information in more detail.

The Company believes that a reasonable range for the proposed relative rates of

return would be in the 0.9 to 1.1 range. As such, a move of approximately 60% towards unity for all schedules met that goal, with the exception of Schedule 131. This schedule only has one customer, and given their present relative rate of return, a move to unity was made.

Proposed Rate Design

Q. Could you please explain the present rate design within each of the Company's present 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 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 $201.30 per month customer charge and a five-tier declining-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 your Exhibits do you show the present and proposed rates for the Company's natural gas service schedules?

A. Page 3 of Exhibit No.___(PDE-7) shows the present and proposed rates under each of the rate schedules, including all present rate adjustments (adders). Column (e) 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 6.1% to the rates of General Service Schedule 101. Is the Company proposing an increase to the present basic/customer charge of $6.00/month under the schedule?

A. Yes. The Company is proposing to increase the basic/customer charge from $6.00 to $10.00 per month.

Q. Why is the Company proposing an increase to the basic charge?

A. The Company believes that the customer/basic charge should recover a reasonable portion of the fixed costs of providing service. Support for this increase is

provided later in my testimony.

Q. What is the proposed change to the rate per therm under Schedule 101 in order to achieve the total proposed revenue increase for the schedule?

A. The Company, as shown in column (e), page 3 of Exhibit No.___(PDE-7), is not proposing a change to the per therm rate for Schedule 101 customers. The total revenue requirement for Schedule 101 would be recovered through the basic charge.

Q. What would be the increase in a residential customer's bill with average usage based on the proposed increase for Schedule 101?

A. The increase for a residential customer using an average of 69 therms of gas per month would be $4.00 per month, or 6.8%. A bill for 69 therms per month would increase from the present level of $58.79 to a proposed level of $62.79, 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. Yes. 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 guidance 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 guidance 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 $4.00 per month is equal to the basic charge increase of $4.00 under Schedule 101. Typically this Schedule 101 basic charge increase, along with any proposed change to the Schedule 101 rate per therm, multiplied by 200 therms, is the calculation used to determine the change in the minimum charge for Schedule 111. However, given that there is no proposed change to the volumetric per therm rate, the minimum charge for Schedule 111 was only increased by $4.00. 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 a uniform percentage increase of 3.4% to the remaining two rate blocks under the schedule, resulting in an overall revenue increase of 3.3% for the schedule.

For Schedule 121, the increase in the minimum charge (for 500 therms or less) is $11.59 for a total charge of $354.05. The minimum charge is derived by adding the proposed Schedule 101 basic charge of $10 to the product of 500 therms multiplied by the difference between the rate in Schedule 101 and the minimum rate under Schedule 121. Below is the calculation:

500 Therms	500
*	
(101 Rate - 121 Minimum Rate)	$ 0.6881
(0.86159-0.17349)	
+	
Schedule 101 Basic Charge	$ 10.00
=	**$ 354.05**

The second, third, and fourth block rates were increased by a uniform percentage of

approximately 3.8% to maintain consistency between the rates for Schedules 111 and 121. The fifth block was not adjusted in order to provide a more meaningful spread between the rate blocks, resulting in an overall revenue increase of 3.3% for the schedule.

Q. How is the Company proposing to spread the proposed increase of $12,000 to the rates under Interruptible Schedule 131?

A. The Company proposes to increase the present four block rates under the schedule by a uniform percentage increase of 2.8%.

Q. Could you please explain the proposed changes in the rates for Transportation Schedule 146?

A. Yes. The Company is proposing to adjust the basic charge and the per therm rates by 11.5%. For the basic charge, that would cause an increase from $201.30 to $225 per month (which was rounded to the nearest $5 increment). For the remaining revenue requirement, 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.____(PDE-7).

Q. Is the Company proposing any other changes to its natural gas service schedules?

A. Yes. The rates contained in Purchase Gas Cost Adjustment Schedule 156 have been incorporated into the present and proposed rates shown on Page 3 of Exhibit No.___(PDE-7). Further, a revised Schedule 156 is filed as part of Exhibit No.___(PDE-6), whereby the present rates under the schedule have been zeroed-out and included in the

Company's proposed general service tariffs.

V. BASIC CHARGE

Q. Why is the Company proposing to increase the electric monthly customer charge from $6.00 to $10.00 per month?

A. A significant portion of the Company's costs are fixed and do not vary with customer usage. These costs include distribution plant and operating costs to provide reliable service to customers. Upon evaluation of the total customer allocated costs, as shown in Exhibit No. __(TLK-4), page 3, line 29, those costs are $10.46 per customer per month. Factoring in distribution demand cost per customer per month of $18.27, as shown in Exhibit No. __(TLK-4), page 4, the total customer and distributed demand monthly cost is $28.72. These are essentially fixed costs that are allocated based on the number of customers served. Given the large disparity between the level of customer and demand costs and the present level of the basic charge, the Company believes that it is appropriate to recover a more reasonable level of these fixed customer costs through the basic charge.

Q. In the Company's last two general rate filings, the Company has proposed relatively small increases in the residential electric basic charge (50 cents and 25 cents, respectively). Why is the Company now proposing an increase of $4.00 per month in this filing?

A. One of the arguments against higher residential basic charges in the past was one of customer understandability and acceptance. Absent compelling arguments to the contrary, as costs to serve customers continue to increase, we believe it is increasingly important that our charges to customers more accurately reflect the actual costs to serve

customers. With regard to fixed charges, many other utility assessments (phone, television, internet) are generally a flat monthly fee. Typically, there is little correlation between the level of use and the monthly amount paid for service related to these other utilities/services. Consumers understand that most of the costs associated with these other utilities/services are fixed, and have become accustomed to paying a relatively constant monthly fee for service or system access.

Publicly-owned electric utilities have been charging higher monthly customer charges for years in order to more accurately reflect (and recover) the fixed costs of providing service. For example, Avista's nearest neighbors in Eastern Washington and North Idaho, Inland Power and Light and Kootenai Electric Cooperative, have a basic charge of $16.80 and $16.50 respectively. Moreover, Puget Sound Energy has had a basic charge of $10.00 for natural gas since 2008.

Q. Turning now to natural gas, why is the Company proposing to increase that monthly customer charge from $6.00 to $10.00 per month?

A. Upon evaluation of the total customer allocated costs, as shown in Exhibit No. __(TLK-7), page 3, line 24, those costs are $16.04 per customer per month. The fixed costs that otherwise include the cost of the meter and service, and the costs associated with billing and providing customer service are $11.43 per customer per month, as shown in Exhibit No. __(TLK-7), page 4 line 22.

Q. What is the consequence to a customer of a Basic Charge that is priced below the cost of providing customer services to that customer?

A. Because rate design is a "zero sum game", if customer charges are set below the cost of providing customer service, then other charges are, by definition, set above their

cost of service. For residential gas and electric customers, the only other charge is the volumetric charge. When volumetric rates are increased above their cost of service to include customer costs that are not in the Basic Charge, several consequences ensue:

- It results in almost all customers paying more per-customer related costs in the winter, even though their customer costs are not higher in the winter, and vice versa in the summer;
- It results in customers paying more customer costs when it is cold, even though customer costs do not vary with temperature.
- It results in the amount of customer costs a customer pays being unpredictable, even though customer costs are actually very predictable.
- A portion of fixed costs of providing service to low usage customers is actually recovered from other higher usage customers served under the same schedule.

In summary, setting the basic charge at a rate substantially less than an amount that covers annual customer costs results in rates that are not equitable and are unnecessarily variable.

Q. If the concern of the Company is recovery of fixed costs, why doesn't it request an electric decoupling mechanism similar to the mechanism this Commission approved on the natural gas side of the business?

A. The request for an increase in the basic charge and requests for mechanisms such as decoupling are not mutually exclusive. As noted in the question, the Company does have a natural gas decoupling mechanism. This mechanism, as approved by the Commission in its last general rate case proceeding, allows for the recovery of up to 45% of its lost margins due to energy conservation (both programmatic and non-programmatic). While this mechanism is an important step towards ensuring fixed cost recovery, there is

still a substantial amount of fixed costs that are subject to recovery in the volumetric charge. Even if the Company were to request a similar electric decoupling mechanism, that mechanism would not remedy the issue. The Company's requested increase in basic charges is a simple way to partially bridge the fixed cost recovery gap.

It should be noted that this is not a new position for the Company. In the Company's last general rate case, Commission Staff proposed an $8 natural gas basic charge, which would increase to $10 over a two year period. The Company's response to that proposal was that "(a)lthough the Company believes a higher basic charge of $8 to $10 per month is a move in the right direction and would be appropriate, it would not be a substitute for decoupling."[5]

Q. But won't increasing the Basic Charge send the wrong price signal through the energy rates?

A. Conservation of electricity and natural gas is important for customers and for the Company, and one might argue that a lower basic charge results in higher commodity prices and a stronger price signal related to volume usage. However, sending a price signal to customers through a residential rate design that contains a three tier increasing block rate for electric (natural gas has just one volumetric rate) was developed for just such a reason. The more electricity that is used, the higher the rate, and therefore the higher the overall customer bill. The important distinction in this filing is that the Company is not requesting to decrease the energy rates, nor is it proposing to reduce the degree of inversion between the rates. As such, the volumetric pricing components will still send a very clear price signal to conserve. It is just not necessary to continue to use an inequitable basic charge to send price signals.

[5] See page 45, KON-1T (Docket Nos. UE-090134, UG-090135 & UG-060518)

Q. Do you have any additional comments related to "price signals"?

A. Yes. Sending a proper price signal is important as I noted above, and I believe that the proper price signal is being maintained. One measure of this it to look to the Company's IRP's to see what the incremental cost of electricity and natural gas is on a forward looking basis, as compared to retail rates. For electricity, the proposed tail-block rate of $0.09170 (usage over 1,300 kWh's) is well above the Company's levelized 20 year forecast of $0.07956 per kWh.[6] For natural gas, the Company included several forecasts in its 2009 Integrated Resource Plan which, for the most part, all show forecasted natural gas prices at Henry Hub over the next ten years being lower than Avista's retail rate[7].

Q. Have you prepared an analysis to show what impact the proposed rate design changes would have on customers?

A. Yes. The Company completed an analysis showing the impact on low, average, and high use electric and natural gas customers. The comparison shows the difference in a customer's bill based on the Basic Charge and volumetric rates being increased on a uniform percentage basis, versus the Company's proposed changes. Table 9 below details results of that analysis for <u>electric</u> customers:

[6] 2009 Avista Electric Integrated Resource Plan, Page 7-1. (see Exhibit No. ___(RLS-2)) The forecast shows $79.56 per mWh.
[7] 2009 Avista Natural Gas Integrated Resource Plan, Page 1.5 (See Exhibit No. ___(KJC-4))

Table 9

Avista - Bill Impacts for Low, Medium and High Electric Customers					
Monthly Bill Impact	Current Billed Rate	Equal Percentage	Avista Proposed	Difference bet. Equal % and Proposed	Percent. Difference
750 kWh/mo Customer	$53.85	$61.82	$62.66	$0.84	**1.4%**
994 kWh/mo Customer	$71.36	$81.93	$81.94	$0.01	**0.0%**
1500 kWh/mo Customer	$110.13	$126.44	$124.61	-$1.83	**-1.4%**

Table 10 below details the analysis for natural gas customers:

Table 10

Avista - Bill Impacts for Low, Medium and High Natural Gas Customers					
Monthly Bill Impact	Current Billed Rate	Equal Percentage	Avista Proposed	Difference bet. Equal % and Proposed	Percent. Difference
50 therms/mo Customer	$44.25	$47.25	$48.25	$1.01	**2.1%**
69 therms/mo Customer	$58.79	$62.78	$62.79	$0.01	**0.0%**
90 therms/mo Customer	$74.86	$79.95	$78.86	-$1.09	**-1.4%**

As you can see, the impact of the Company's proposed change to the basic charge varies based on monthly consumption. For an electric customer who uses less than the average 994 kWh's and/or 69 therms per month, the percentage impact will be slightly higher than for those customers who use more than the average. We believe the improvement in matching customer payment of fixed costs with the fixed costs to serve customers, together with removing part of the inequity among customers on the amount of fixed costs paid, warrants this relatively small bill impact.

The table below shows a comparison of monthly bills for an electric customer with average usage for a 12-month period. It shows the difference in the monthly bills with a uniform percentage increase to the basic charge and volumetric rates, versus the

Company's proposal. The table illustrates the reduction in payment of fixed costs in the winter months, and increased payment in the summer, with the net result being improved alignment of payment of fixed costs by customers with the fixed costs to serve customers, with no net annual difference[8] in overall payment.

Table 11

Monthly Bills of an Average Electric Customer

Month	kWh's	Equal Percentage	Avista Proposed	Higher / Lower Bill
January	1,343	$111.29	$110.09	($1.20)
February	1,191	$98.16	$97.50	($0.66)
March	1,139	$93.88	$93.39	($0.48)
April	852	$70.23	$70.72	$0.49
May	827	$68.17	$68.74	$0.58
June	783	$64.54	$65.26	$0.73
July	798	$65.78	$66.45	$0.67
August	867	$71.46	$71.90	$0.44
September	762	$62.81	$63.61	$0.80
October	855	$70.47	$70.95	$0.48
November	1,129	$93.05	$92.60	($0.45)
December	1,376	$114.48	$113.14	($1.34)
	11,922	**$984.31**	**$984.36**	**$0.05**

The table below provides a similar comparison for a 12-month period for a natural gas customer with average usage. The net result[9] is similar to the electric results above, namely a better alignment of payment of fixed costs by customers with the fixed costs to serve customers.

[8] Annual electric billing difference of $0.05 is a result of rounding.
[9] Annual natural gas billing difference of $0.07 is a result of rounding.

Table 12

Monthly Bills of an Average Natural Gas Customer				
Month	Therms	Equal Percentage	Avista Proposed	Higher / Lower Bill
January	147	$126.75	$122.65	($4.10)
February	116	$101.03	$98.58	($2.45)
March	101	$88.82	$87.16	($1.66)
April	57	$52.96	$53.60	$0.64
July	36	$35.75	$37.49	$1.74
August	25	$26.61	$28.95	$2.33
September	15	$18.60	$21.44	$2.84
October	16	$19.23	$22.03	$2.80
November	19	$21.73	$24.37	$2.64
October	53	$49.94	$50.78	$0.83
November	96	$84.72	$83.32	($1.40)
December	148	$127.59	$123.44	($4.15)
	828	**$753.75**	**$753.82**	**$0.07**

Q. Has the Commission recently commented on what they believe an appropriate basic charge should be?

A. Yes. In 2007, in Puget Sound Energy Dockets UE-060266 and UG-060267 (consolidated), the Commission approved a $8.25 natural gas basic charge (subsequently increased to $10) and stated:

> This will result in the Company recovering about one-fourth of its fixed costs allocated to residential customers via a fixed charge on each customer's bill. This is about eight to ten percent of an average customer's total bill, considering both fixed and variable costs. This seems to us the right balance point for the recovery of fixed costs via the customer charge.[10]

Avista's proposed $10 basic charge is approximately 15.9% of the proposed average bill for natural gas customers (13% excluding the temporary gas cost refund) and 12.2% for electric customers. This is well within the range of reasonableness, especially when viewed as a percentage of base rates.

[10] Order No. 08, Dockets UE-060266 and UG-060267, Para. 139

Q. Would you characterize the Company's proposal as fair?

A. Yes. High use customers clearly subsidize low use customers as it relates to covering the fixed costs of service. One clear example to demonstrate this is to think of customers who have a second home or vacation home in the Company's service territory. The fixed costs to serve these customers are not necessarily different than a "traditional" customer who lives in their home year-round. However, if a customer's electric usage only occurs in a few months of the year, they are clearly being subsidized by traditional customers who have higher usage (and higher fixed cost charges recovered through the volumetric rate).

Q. Please discuss your view of the impacts of this request on your limited income customers.

A. There are two different implications of the Company's proposal. The first implication is for limited income electric customers, many whom would benefit from the Company's proposal. Traditional thinking might lead one to believe that a low income electric customer would tend to be a low user of electricity. Although the Company has not conducted a demographic survey of its customers in recent years, the limited data that we do have would suggest that just the opposite is true.

A majority of our customers have natural gas for space and water heating, and therefore may have low average electric usage during the winter. However, many low income customers, I believe, tend to still use electricity for space and water heating. These customers, in my view, tend to live in apartments (which in Avista's service territory predominantly have electric space and water heat), live in areas where natural gas is not available, or live in areas with natural gas, but cannot afford to convert. These low income

customers, with electric space and water heat, can have electric usage in the tail-block (above 1,300 kWh's) during the winter months. Having a lower basic charge and higher tail-block rate penalizes these customers, as these customers are more susceptible to use in the tail-block. A higher basic charge, on the other hand, would result in lower volumetric rates (than they otherwise would be the case), providing some relief to these high use customers during the winter months.

Q. What are the implications for limited income natural gas customers?

A. Average use limited income natural gas customers would tend to pay slightly higher natural gas bills than they would under the equal percentage methodology used by the Company as shown in the examples earlier in my testimony. Data gathered as part of the review of the Company's natural gas Decoupling Mechanism showed that limited income natural gas customers tend to use slightly less natural gas (58 therms per month[11]) than the traditional residential customer (69 therms per month). As shown in the table below, while there is an impact, it is relatively small both on a dollar and percentage basis (between 0% and 1.1%).

Table 13

Avista - Residential/Limited Income Natural Gas Customer Impact					
	Current Rates	Equal Percentage	Avista Proposed	Difference bet. Equal % & Proposed	Percent. Difference
Customer Charge	$6.00	$6.37	$10.00	$3.63	
Billing Rate	$0.76509	$0.81759	$0.76509	-$0.05250	
Monthly Bill Impact					
58 Therm/mo Customer	$50.38	$53.79	$54.38	$0.59	**1.1%**
69 Therm/mo Customer	$58.79	$62.78	$62.79	$0.01	**0.0%**

[11] Titus "Evaluation of Avista Gas Decoupling Mechanism Pilot", Page 81, Table K10. See Docket UG-060518.

Q. Has the Company done any recent research with regard to the limited income customers it serves?

A. Yes. In 2009, Avista commissioned a study by the Institute for Public Policy and Economic Analysis at Eastern Washington University. The purpose of the study was "Assessing Heating Assistance Programs in Spokane County".[12] A copy of this study appears as Exhibit No.___(DFK-3) to Mr. Kopczynski As noted in that report, the study examined "the recent experience of the two largest heating assistance programs in Spokane County: the federal Low Income Home Energy Assistance Program (LIHEAP) and the Avista Utilities-funded Low Income Rate Assistance Program (LIRAP). The study's central goal (was) to assess the reach of these programs among the eligible population."[13] The study had the following key findings:

1. The average heating burden (heating costs divided by total household income) for a household in the US is 1.3%.[14]
2. The average heating burden for households in Spokane County is 1.4%, very close to the US average.[15]
3. The average gross heating burden for low-income customers (defined as those customers assisted by Spokane Neighborhood Action Programs, or SNAP, which uses the 125% of the federal poverty guideline) is 6.1%.[16]
4. The average net heating burden for low-income customers, assisted by SNAP, is 1.4% (net being defined as heating costs less energy grants, divided by total income).[17]
5. In 2009, the report shows that 30% of eligible households were assisted by SNAP. This is much higher than the national average of 16%.[18]

In short, this report demonstrates that limited income customers served by SNAP have a net energy (heating) burden that is similar to the average household in Spokane County.

[12] "Assessing Heating Assistance Programs in Spokane County", Institute for Public Policy & Economic Analysis (Grant Forsyth, PhD, D. Patrick Jones, PhD, and Mark Wagner). January 2010.
[13] id., Page 1
[14] id., Page 2
[15] id., Page 2
[16] id., Page 3
[17] id., Page 3
[18] id., Page 3

While a slight increase in their monthly bill may occur because of a higher natural gas fixed charge, this data shows that many limited income customers are receiving assistance to help offset increasing utility bills. Further, as discussed in Company witness Kopczynski's testimony, the Company offers a number of programs to help mitigate increasing rate impacts on its limited income customers. Those programs include the Company's limited income DSM offerings, Low Income Rate Assistance Program (LIRAP), Senior Energy Assistance, and Project Share.

VI. DECOUPLING - RATE SCHEDULE APPLICABILITY

Q. What is the Company's response to the directive from the Commission in its most recent rate case to address the recovery of DSM-related lost margin from all natural gas rate schedules?

A. At page 119, paragraph 303 of Order 10 in UE-090134, UG-090135 & UG-060518 (consolidated), the Commission stated:

> By reducing the Company's natural gas load, including its peak requirements, Avista's conservation program benefits all customers. In fact, the decoupling program includes conservation from all rate schedules in setting its targets and determining its success. Even so, as now put in place, the program's lost margin is only collected from Schedule 101 customers. Following the principle of costs following benefits discussed above, we expect the parties to address whether the program should recover DSM-related lost margin from all rate schedules in Avista's next general rate case.

With regard to the principle of costs following benefits for Schedule 101, the costs associated with these programs, specifically DSM lost margin, is recovered only from Schedule 101 customer, and therefore there is alignment of costs and benefits for Schedule 101.

Q. Is the Company proposing a mechanism to recover DSM lost margin from large commercial and industrial customers?

A. Not at this time. While the Company believes that it would be appropriate to recover programmatic and non-programmatic lost margin from these customers, the amount of lost margin, at least for programmatic savings, is not material enough at this time to warrant a change to the current decoupling mechanism. Based on the verified 2008 DSM savings for large commercial and industrial customers, the annual lost margin (using present margins), as shown in Table 14 below, would be approximately $34,135.

Table 14 – Lost Margin for Large Commercial & Industrial Customers

Rate Schedule	Verified Energy Savings	Margin Rate (Tail-Block)	Lost Margin
111/112	238,741	$ 0.14176	$ 33,843.92
121/122	2,999	$ 0.09720	$ 291.50
131/132	0	$ 0.08719	$ -
Total	**241,740**		**$ 34,135.43**

If and when the lost margin becomes a more significant amount, the Company would plan to address the issue at that time.

Q. What is the status of the Evaluation, Measurement and Verification (EM&V) collaborative?

A. In Order 10, referenced above, the Commission ordered a collaborative for the parties involved in that case to address these issues, and to file the final Evaluation, Measurement and Verification plan with the Commission by September 1, 2010. Company witness Mr. Folsom, in his pre-filed direct testimony, provides an update on that

collaborative, as well as on the collaborative relating to DSM acquisition from the limited income sector.

Q. Does this conclude your pre-filed, direct testimony?

A. Yes it does.