

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-11 _____

DOCKET NO. UG-11 _____

DIRECT TESTIMONY OF

TARA L. KNOX

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

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

A. My name is Tara L. Knox and my business address is 1411 East Mission Avenue, Spokane, Washington. I am employed as a Senior Regulatory Analyst in the State and Federal Regulation Department.

Q. Would you briefly describe your duties?

A. Yes. I am responsible for preparing the regulatory cost of service models for the Company, as well as providing support for the preparation of results of operations reports.

Q. What is your educational background and professional experience?

A. I am a graduate of Washington State University with a Bachelor of Arts degree in General Humanities in 1982, and a Master of Accounting degree in 1990. As an employee in the State and Federal Regulation Department at Avista since 1991, I have attended several ratemaking classes, including the EEI Electric Rates Advanced Course that specializes in cost allocation and cost of service issues. I have also been a member of the Cost of Service Working Group and the Northwest Pricing and Regulatory Forum, which are discussion groups made up of technical professionals from regional utilities and utilities throughout the United States and Canada concerned with cost of service issues.

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

A. My testimony and exhibits will cover the Company's electric and natural gas cost of service studies performed for this proceeding. Additionally, I am sponsoring the electric and natural gas revenue normalization adjustments to the test year results of operations and the

1 proposed retail revenue credit rate to be used in the Energy Recovery Mechanism. A table of
2 contents for my testimony is as follows:

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13 **Q. Are you sponsoring any exhibits in this case?**

14 A. Yes. I am sponsoring Exhibit No.__(TLK-2), which illustrates the proposed
15 retail revenue credit rate calculation. Related to the electric cost of service study, I am
16 sponsoring Exhibit No.__(TLK-3), the electric cost of service study process description, and
17 Exhibit No.__(TLK-4), the electric cost of service study summary results.

18 Finally, related to the natural gas cost of service study, I am sponsoring Exhibit No.__(
19 TLK-5), the natural gas cost of service study process description, and Exhibit No.__(TLK-6),
20 the natural gas cost of service study summary results.

21 **Q. Were these exhibits prepared by you or under your direction?**

22 A. Yes, they were.

23 **II. REVENUE NORMALIZATION**

24 **Electric Revenue Normalization**

25 **Q. Would you please describe the electric revenue adjustment included in**
26 **Company witness Ms. Andrews pro forma results of operations?**

1 A. Yes. The electric revenue normalization adjustment represents the difference
2 between the Company's actual recorded retail revenues during the twelve months ended
3 December 2010 test period, and retail revenues on a normalized (pro forma) basis. The total
4 revenue normalization adjustment increases Washington net operating income by \$19,882,000,
5 as shown in column (AF) on page 9 of Exhibit No. ____ (EMA-2). The revenue normalization
6 adjustment consists of three primary components: 1) re-pricing customer usage (adjusted for any
7 known and measurable changes) at base tariff rates presently in effect, 2) adjusting customer
8 loads and revenue to a 12-month calendar basis (unbilled revenue adjustment), and 3) weather
9 normalizing customer usage and revenue¹.

10 **Q. Since these three elements are combined into a single adjustment, would you**
11 **please identify the impact (before taxes and revenue related expenses) of each component?**

12 A. Yes. The re-pricing of billed usage comprises the majority of the change in test
13 year revenue. The combined impact of the rate increase effective December 1, 2010², and the
14 elimination of revenue and amortization expense from adder schedules (Schedule 59 Residential
15 Exchange and Schedule 91 Public Purpose Tariff Rider³), is an increase in net revenue of
16 \$29,105,000. Re-pricing of unbilled calendar usage and elimination of unbilled adder schedule
17 revenue and expense results in a net revenue reduction of \$2,894,000⁴. Finally, the weather
18 normalization adjustment increases revenue by \$5,305,000. The combined impact of these

¹ Documentation related to this adjustment is detailed in the Knox workpapers accompanying this case.

² WUTC Docket No. UE-100467.

³ City Business and Occupation Taxes, Energy Recovery Mechanism, and Optional Renewable Power revenues are eliminated in separate adjustments.

⁴ The unbilled adjustment consists of removing December 2009 usage billed in January 2010 from the 2010 test year, adding December 2010 usage billed in January 2011 to the 2010 test year, and re-pricing the net adjustment to usage at December 1, 2010 rates.

1 elements is an increase of \$31,516,000 which, after revenue-related expenses and income tax,
2 results in the increase to net operating income of \$19,882,000.

3 **Q. Would you please briefly discuss electric weather normalization?**

4 A. Yes. The Company's electric weather normalization adjustment calculates the
5 change in kWh usage required to adjust actual loads during the twelve months ended December
6 2010 test period to the amount expected if weather had been normal. This adjustment
7 incorporates the effect of both heating and cooling on weather-sensitive customer groups. The
8 weather adjustment is developed from regression analysis of ten years of billed usage per
9 customer and billing period heating and cooling degree-day data. The resulting seasonal weather
10 sensitivity factors (use-per-customer-per-heating-degree day and use-per-customer-per-cooling-
11 degree day) are applied to monthly test period customers and the difference between normal
12 heating/cooling degree-days and monthly test period observed heating/cooling degree-days.

13 **Q. Have the seasonal weather sensitivity factors been updated since the last rate**
14 **case?**

15 A. Yes. The factors used in the weather adjustment are based on regression analysis
16 of monthly billed usage per customer from January 2000 through December 2009 which is the
17 most recent completed analysis. Autoregressive terms were included in the regressions in order
18 to correct for autocorrelation in the data.

19 **Q. What data did you use to determine "normal" heating and cooling degree**
20 **days?**

21 A. Normal heating and cooling degree days are based on a rolling 30-year average of
22 heating and cooling degree-days reported for each month by the National Weather Service for the
23 Spokane Airport weather station. Each year the normal values are adjusted to capture the most

1 recent year with the oldest year dropping off, thereby reflecting the most recent information
2 available at the end of each calendar year.

3 **Q. Is this proposed weather adjustment methodology consistent with the**
4 **methodology utilized in the Company's last general rate case in Washington?**

5 A. Yes. The process for determining the weather sensitivity factors and the monthly
6 adjustment calculation are consistent with the methodology presented in Docket No. UE-100467.

7 **Q. What was the impact of electric weather normalization on the twelve months**
8 **ended December 2010 test year?**

9 A. Weather was warmer than normal during the winter, and cooler than normal
10 during the spring and summer of 2010. The adjustment to normal required the addition of 334
11 heating degree-days during the heating season⁵ and 59 cooling degree-days. The total adjustment
12 to Washington sales volumes was an addition of 62,927,205 kWhs which is approximately 1.1%
13 of billed usage.

14 **Natural Gas Revenue Normalization**

15 **Q. Would you please describe the natural gas revenue adjustment included in**
16 **Ms. Andrews pro forma results of operations?**

17 A. Yes. The natural gas revenue normalization adjustment is similar to the electric
18 adjustment and represents the difference between the Company's actual recorded retail revenues
19 during the twelve months ended December 2010 test period and retail revenues on a normalized
20 (pro forma) basis. The adjustment includes the re-pricing of pro forma sales and transportation
21 volumes at present rates using pro forma sales volumes that have been adjusted for unbilled
22 sales, abnormal weather, and any material customer load or schedule changes. The rates used

⁵ The heating season includes the months of January through June and October through December.

1 exclude: 1) Temporary Gas Rate Adjustment Schedule 155, which reflects the approved
2 amortization rate for prior deferred gas costs approved in the Company's last PGA filing, 2)
3 Public Purposes Rider Adjustment Schedule 191, and 3) Natural Gas Decoupling Rate
4 Adjustment Schedule 159⁶.

5 **Q. Does the Revenue Normalization Adjustment contain a component reflecting**
6 **normalized gas costs?**

7 A. Yes. Purchase gas costs are normalized using the gas costs approved by the
8 Commission in Docket No. UG-101539, the Company's 2010 PGA filing, as set forth under
9 Schedule 150. These gas costs, effective November 1, 2010, are applied to the pro forma retail
10 sales volumes so that there is a matching of revenues and gas costs.

11 **Q. Have you determined the impact of each of the components of this**
12 **adjustment?**

13 A. Yes. The re-pricing of billed revenue and gas costs increased margin⁷ by
14 \$4,184,000. Re-pricing unbilled revenue and gas costs decreased margin by 565,000, and the
15 weather adjustment at present rates increased margin by \$2,254,000.

16 The total net amount of the natural gas revenue normalization adjustment, which includes
17 the related purchase gas cost normalization, is an increase to net operating income of \$3,300,000,
18 as shown in column (I), page 6 of Exhibit No. ___(EMA-3).

19 **Q. Would you please briefly discuss natural gas weather normalization?**

20 A. Yes. The natural gas weather normalization adjustment is developed from a
21 regression analysis of ten years of billed usage per customer and billing period heating degree-

⁶ Documentation related to this adjustment is detailed in the Knox workpapers accompanying this case.

⁷ The term "margin" in this context consists of revenues less gas costs and adder schedule amortization expenses but does not include the effect of revenue related expenses or income taxes.

1 day data. The resulting seasonal weather sensitivity factors (use-per-customer-per-heating-
2 degree day) are applied to monthly test period customers and the difference between normal
3 heating degree-days and monthly test period observed heating degree-days. This calculation
4 produces the change in therm usage required to adjust existing loads to the amount expected if
5 weather had been normal.

6 **Q. In your discussion of electric weather normalization you indicated that the**
7 **adjustment utilized sensitivity factors from the ten year period January 2000 through**
8 **December 2009. Is this true for natural gas as well?**

9 A. Yes, the natural gas weather adjustment utilized updated weather sensitivity
10 factors.

11 **Q. What data did you use to determine “normal” heating degree days?**

12 A. Normal heating degree-days are based on a rolling 30-year average of heating
13 degree-days reported for each month by the National Weather Service for the Spokane Airport
14 weather station. Each year the normal values are adjusted to capture the most recent year with
15 the oldest year dropping off, thereby reflecting the most recent information available at the end
16 of each calendar year.

17 **Q. Is this proposed weather adjustment methodology consistent with the**
18 **methodology utilized in the Company’s last general rate case in Washington?**

19 A. Yes. The process for determining the weather sensitivity factors and the monthly
20 adjustment calculation are consistent with the methodology presented in Docket No. UG-100468.

21 **Q. What was the impact of natural gas weather normalization on the twelve**
22 **months ended December 2010 test year?**

1 and Transmission Costs” at the bottom of page 1 shows the resulting production and transmission
2 cost components.

3 Page 2 shows the revenue requirement calculation on the production and transmission
4 cost components. The rate of return and debt cost percentages on Line 2 are inputs from the
5 proposed cost of capital. The normalized retail load on Line 10 comes from the workpapers
6 supporting the revenue normalization and energy efficiency load adjustments. The proposed
7 retail revenue credit rate is shown on Line 11 and represents the average production and
8 transmission cost-per-kWh proposed to be embedded in Washington customer retail rates.

9 The proposed retail revenue credit rate is \$0.05301 per kWh or \$53.01 per mWh. The
10 calculation of the retail revenue credit rate will be revised based on the final production and
11 transmission costs and rate of return that are approved by the Commission in this case.

12 **IV. ELECTRIC COST OF SERVICE**

13 **Q. Please briefly summarize your testimony related to the electric cost of service**
14 **study.**

15 A. I believe the Base Case cost of service study presented in this case is a fair
16 representation of the costs to serve each customer group. The Base Case study shows Residential
17 Service Schedule 1, Extra Large General Service Schedule 25 and Pumping Service Schedule 31
18 provide substantially less than the overall rate of return under present rates. General Service
19 Schedule 11, Large General Service Schedule 21 and Street and Area Lights provide more than
20 the overall rate of return under present rates.

21 **Q. Please identify the Company’s electric cost studies presented to this**
22 **Commission in the last five years as required by WAC 480-07-510 (6).**

1 A. Electric cost of service studies were presented to this Commission in Docket No.
2 UE-070804, Docket No. UE-080416, Docket No. UE-090134, and Docket No. UE-100467.

3 **Q. What is an electric cost of service study and what is its purpose?**

4 A. An electric cost of service study is an engineering-economic study, which
5 separates the revenue, expenses, and rate base associated with providing electric service to
6 designated groups of customers. The groups are made up of customers with similar load
7 characteristics and facilities requirements. Costs are assigned or allocated to each group based
8 on (among other things), test period load and facilities requirements, resulting in an evaluation of
9 the cost of the service provided to each group. The rate of return by customer group indicates
10 whether the revenue provided by the customers in each group recovers the cost to serve those
11 customers. The study results are used as a guide in determining the appropriate rate spread
12 among the groups of customers. Exhibit No. ____ (TLK-3) explains the basic concepts involved in
13 performing an electric cost of service study. It also details the specific methodology and
14 assumptions utilized in the Company's Base Case cost of service study.

15 **Q. What is the basis for the electric cost of service study provided in this case?**

16 A. The electric cost of service study provided by the Company as Exhibit
17 No. ____ (TLK-4) is based on the twelve months ended December 2010 test year pro forma results
18 of operations presented by Ms. Andrews in Exhibit No. ____ (EMA-2).

19 **Q. Would you please explain the cost of service study presented in Exhibit No.**
20 **____ (TLK-4)?**

21 A. Yes. Exhibit No. ____ (TLK-4) is composed of a series of summaries of the cost of
22 service study results. The summary on page 1 shows the results of the study by FERC account
23 category. The rate of return by rate schedule and the ratio of each schedule's return to the overall

1 return are shown on Lines 39 and 40. This summary was provided to Company witness Mr.
2 Ehrbar for his work on rate spread and rate design. The results will be discussed in more detail
3 later in my testimony.

4 Pages 2 and 3 are both summaries that show the revenue-to-cost relationship at current
5 and proposed revenue. Costs by category are shown first at the existing schedule returns
6 (revenue); next the costs are shown as if all schedules were providing equal recovery (cost).
7 These comparisons show how far current and proposed rates are from rates that would be in
8 alignment with the cost study. Page 2 shows the costs segregated into production, transmission,
9 distribution, and common functional categories. Line 44 on page 2 shows the target change in
10 revenue which would produce unity in this cost study. Page 3 segregates the costs into demand,
11 energy, and customer classifications. Page 4 is a summary identifying specific customer related
12 costs embedded in the study.

13 The Excel model used to calculate the cost of service and supporting schedules has been
14 included in its entirety both electronically and in hard copy in the workpapers accompanying this
15 case.

16 **Q. Given that the specific details of this methodology are described in Exhibit**
17 **No. ____ (TLK-3), would you please give a brief overview of the key elements and the history**
18 **associated with those elements?**

19 A. Yes. In general, the cost study follows the methodology established in Docket
20 No. UE-920499 for Puget Sound Power and Light (now Puget Sound Energy). Production and
21 transmission costs are classified to energy and demand by a peak credit analysis. The definition
22 of “peaks” and “peak credit” specific to Avista have been accepted by the Commission for Avista
23 in Docket No. UE-991606 and confirmed in Docket No. UE-050482. As I will discuss later in

1 my testimony, the electric cost of service study presented in this case includes a revision to the
2 Avista-specific peak credit analysis.

3 Distribution costs are classified and allocated by the basic customer theory⁹ that was
4 derived directly from the methodology approved for Puget in Docket No. UE-920499.
5 Administrative and general costs are first directly assigned to production, transmission,
6 distribution, or customer relations functions. The Commission found this process acceptable in
7 Avista's Docket No. UE-991606. The remaining administrative and general costs are
8 categorized as common costs and have been allocated by a variety of factors as approved by this
9 Commission for Puget in Docket No. UE-920499. The specific factors and items they are
10 applied to are described in detail in Exhibit No. ____ (TLK-3), on pages 5 and 9.

11 **Q. Does the Company's electric Base Case cost of service study follow the**
12 **methodology filed in the Company's last electric general rate case in Washington?**

13 A. In most respects, yes. The Base Case cost of service study was prepared using the
14 methodology applied to the study presented in Docket No. UE-050482 through Docket No. UE-
15 090134 except that the peak credit classification of production and transmission costs has been
16 revised. While a revision to the peak credit classification of production and transmission costs
17 was also proposed in Docket No. UE-100467, the cost of service methodology change was not
18 part of settlement in that case. Therefore the "Prior Methodology" continues to refer to the study
19 methodology last presented in Docket No. UE-090134.

20 **Q. Why is the Company proposing to revise the method for classifying**
21 **production and transmission costs into energy-related and demand-related components?**

⁹ Basic customer theory classifies only meters, services and street lights as customer-related plant; all other distribution facilities are considered demand-related

1 A. In conjunction with Docket No. UE-100467, the Company had examined the
2 Avista-specific peak credit classification methodology applied to production and transmission
3 functional costs. It was determined that the prior methodology was complicated to compute and
4 apply, unrelated to the actual usage of the system, and has a tendency to shift costs back and
5 forth between energy and demand with changes in the cost of natural gas to fuel combustion
6 turbines. The peak credit method proposed by Avista in this case provides a less complex way
7 to determine a fair apportionment of production and transmission costs between energy and
8 demand, is directly related to our system, and is expected to be stable both during the pendency
9 of a case and over time from case to case.

10 **Q. How was the prior peak credit methodology determined and applied?**

11 A. In the Company's prior cost of service studies, Avista's electric system resource
12 costs were classified to energy and demand using a comparison of the replacement cost per kW
13 of the Company's peaking units, to the replacement cost per kW of the Company's thermal and
14 hydro plants (separately). This analysis created separate peak credit ratios applied to thermal
15 plant and hydro plant. Transmission costs were assigned to energy and demand by a 50/50
16 weighting of the thermal and hydro peak credit ratios. Fuel and load dispatching expenses were
17 classified entirely to energy, and peaking plant related costs were classified entirely to demand.

18 **Q. What is the Company proposing in this case with regard to the peak credit**
19 **methodology?**

1 A. In this case the Company is proposing to use the system load factor to determine
2 the proportion of the production function that is demand-related.¹⁰ This single peak credit ratio
3 is then applied uniformly to all production costs.

4 In Washington, transmission costs have traditionally been treated as an extension of the
5 generation system, therefore, the revised peak credit ratio has also been applied to transmission
6 costs in this study.

7 **Q. Is this the same peak credit calculation proposed in Docket No. UE-100467?**

8 A. No, it is not. In that case we proposed an IRP-based analysis of the long term
9 costs of the incremental capacity resource (a gas-fired combined-cycle combustion turbine in the
10 2009 IRP) remaining after the energy is dispatched into the marketplace.

11 **Q. Why have you moved away from that approach in this case?**

12 A. We had proposed the same methodology in our 2010 Idaho general rate case
13 (IPUC Case No. AVU-E-10-01). The settlement in that docket called for a multi-party workshop
14 to discuss the pros and cons of the proposed methodology. A number of issues were raised in the
15 workshop which led to a re-evaluation of the long term stability of that approach, as well as the
16 applicability of an entirely future-based relationship in an embedded cost study. The system load
17 factor alternative was raised during the workshop, and the Company determined that this
18 approach to peak credit better met our requirements to improve the production and transmission
19 cost classification process.

20 **Q. What are the benefits of using the system load factor to determine the peak**
21 **credit ratio?**

¹⁰ One minus the load factor equals the demand percentage or peak credit ratio.

1 A. There are several benefits to the system load factor approach for identifying the
2 demand-related proportion of production costs. 1) It is simple and straightforward to calculate,
3 2) it is directly related to the system and test year under evaluation, and 3) the relationship should
4 remain relatively stable from year to year.

5 **Q. What is the net effect of the proposed change in the peak credit method?**

6 A. The net effect of this change is to slightly increase the overall production and
7 transmission costs that are classified as demand-related. Using the prior method, approximately
8 30.57% of total production and transmission costs (29% of total production costs and 42% of
9 total transmission costs) were classified as demand-related. Under the proposed method, 34.64%
10 of total production and transmission costs are classified as demand-related. This change shifts
11 costs away from high load factor customer groups (Schedules 21 and 25) as well as customer
12 groups which have a limited contribution to system peak usage (pumping and street lighting).

13 **Q. What are the results of the Company's electric cost of service study presented**
14 **in this case?**

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

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1 **Table 1**

<u>Customer Class</u>	<u>Rate of Return</u>	<u>Return Ratio</u>
Residential Service Schedule 1	3.85%	0.63
General Service Schedule 11	12.02%	1.96
Large General Service Schedule 21	9.13%	1.49
Extra Large General Service Schedule 25	4.55%	0.74
Pumping Service Schedule 31	5.60%	0.92
Lighting Service Schedules 41 - 49	<u>8.97%</u>	<u>1.47</u>
Total Washington Electric System	<u>6.12%</u>	<u>1.00</u>

2 As can be observed from the above table, residential and extra large general service
3 schedules (1 and 25) show significant under-recovery of the costs to serve them, the pumping
4 service schedule (31) shows moderate under-recovery, while the general, large general, and
5 lighting service schedules (11, 21, and 41 - 49) show over-recovery of the costs to serve them.
6 The summary results of this study were provided to Mr. Ehrbar as an input into development of
7 the proposed rates.

V. NATURAL GAS COST OF SERVICE

9 **Q. Please identify the natural gas cost studies presented to this Commission in**
10 **the last five years as required by WAC 480-07-510 (6).**

11 A. Natural gas cost of service studies were filed with this Commission in Docket No.
12 UG-100468, Docket No. UG-090135, Docket No. UG-080417 and Docket No. UG-070805.

13 **Q. Please describe the natural gas cost of service study and its purpose.**

14 A. A natural gas cost of service study is an engineering-economic study which
15 separates the revenue, expenses, and rate base associated with providing natural gas service to
16 designated groups of customers. The groups are made up of customers with similar usage

1 characteristics and facility requirements. Costs are assigned in relation to each group's test year
2 load and facilities requirements, resulting in an evaluation of the cost of the service provided to
3 each group. The rate of return by customer group indicates whether the revenue provided by the
4 customers in each group recovers the cost to serve those customers. The study results are used as
5 a guide in determining the appropriate rate spread among the groups of customers. Exhibit
6 No.__(TLK-5) explains the basic concepts involved in performing a natural gas cost of service
7 study. It also details the specific methodology and assumptions utilized in the Company's Base
8 Case cost of service study.

9 **Q. What is the basis for the natural gas cost of service study provided in this**
10 **case?**

11 A. The cost of service study provided by the Company as Exhibit No.__(TLK-6) is
12 based on the twelve months ended December 2010 test year pro forma results of operations
13 presented by Ms. Andrews in Exhibit No.__(EMA-3).

14 **Q. Would you please explain the cost of service study presented in Exhibit**
15 **No.__(TLK-6)?**

16 A. Yes. Exhibit No. ___(TLK-6) is composed of a series of summaries of the cost of
17 service study results. Page 1 shows the results of the study by FERC account category. The rate
18 of return and the ratio of each schedule's return to the overall return are shown on lines 38 and
19 39. This summary is provided to Mr. Ehrbar for his work on rate spread and rate design. The
20 results will be presented later in my testimony. Additional summaries show the costs organized
21 by functional category (page 2) and classification (page 3), including margin and unit cost
22 analysis at current and proposed rates. Finally, page 4 is a summary identifying specific
23 customer related costs embedded in the study.

1 The Excel model used to calculate the cost of service and supporting schedules has been
2 included in its entirety both electronically and hard copy in the workpapers accompanying this
3 case.

4 **Q. Does the Natural Gas Base Case cost of service study utilize the methodology**
5 **from the Company’s last natural gas case in Washington?**

6 A. With the exception of the ratio used to assign Jackson Prairie Storage costs
7 discussed below, the Base Case cost of service study was prepared using the same methodology
8 applied to the study presented in Docket No. UG-100468.

9 **Q. What are the key elements that define the cost of service methodology?**

10 A. Allocations of gas costs reflect the current purchased gas tracker methodology.
11 Underground storage costs are segregated proportionately into commodity storage benefits for
12 sales customers and load balancing benefits for all customers. Natural gas main investment has
13 been segregated into large and small mains. Large usage customers that take service from large
14 mains do not receive an allocation of small mains. Meter installation and services investment is
15 allocated by number of customers weighted by the relative current cost of those items. System
16 facilities that serve all customers are classified by the peak and average ratio that reflects the
17 system load factor, then allocated by coincident peak demand and throughput, respectively.
18 Demand side management costs (if any) are treated in the same way as system facilities. General
19 plant is allocated by the sum of all other plant. Administrative & general expenses are
20 segregated into labor-related, plant-related, revenue-related, and “other”. The costs are then
21 allocated by factors associated with labor, plant in service, or revenue, respectively. The “other”
22 A&G amounts get a combined allocation that is one-half based on O&M expenses and one-half

1 based on throughput. A detailed description of the methodology is included in Exhibit
2 No.__(TLK-5).

3 **Q. Does this methodology follow previously-approved methods?**

4 A. Yes, with the exception of Company-specific purchased gas and related items that
5 match the PGA assumptions, the methodology I have presented here, and in prior cases before
6 this Commission, replicates the methodology established in Docket No. UG-940814 for
7 Washington Natural (now Puget Sound Energy).

8 **Q. Does the relationship between sales commodity and throughput (balancing)**
9 **used to assign costs to underground storage differ from prior cases?**

10 A. Yes, with the additional Jackson Prairie storage that the utility received to serve
11 customers beginning May 1, 2011, the Company believed it was necessary to reassess the proper
12 relationship that the additional storage provides between sales commodity and throughput
13 (balancing). Company witness Mr. Christie provides further testimony on this issue in his pre-
14 filed, direct testimony. The results of this analysis were an 87% sales commodity and 13%
15 throughput (balancing) ratio, versus the 80% sales commodity and 20% throughput (balancing)
16 ratio that had been utilized in prior cases.

17 **Q. What are the results of the Company's natural gas cost of service study?**

18 A. I believe the Base Case cost of service study presented in this filing is a fair
19 representation of the costs to serve each customer group. The study indicates that the Residential
20 service schedule (101) is providing slightly less than the overall return (unity), and Small Firm
21 general, Large Firm general, Interruptible and Transportation service schedules (111, 121, 131
22 and 146) are providing slightly more than unity. All schedules are currently providing return
23 ratios that are relatively close to unity.

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

3 **Table 2**

<u>Customer Class</u>	<u>Rate of Return</u>	<u>Return Ratio</u>
Residential Service Schedule 101	5.98%	0.95
Small Firm Service Schedule 111	7.48%	1.18
Large Firm Service Schedule 121	7.07%	1.12
Interruptible Service Schedule 131	6.56%	1.04
Transportation Service Schedule 146	<u>7.23%</u>	<u>1.14</u>
Total Washington Natural Gas System	<u>6.31%</u>	<u>1.00</u>

4 The summary results of this study were provided to Mr. Ehrbar as an input into
 5 development of the proposed rates.

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

7 A. Yes.