

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND)	
TRANSPORTATION COMMISSION,)	
)	
Complainant,)	DOCKET NOS. UE-140188 and
)	UG-140189 (<i>Consolidated</i>)
)	
v.)	
)	
AVISTA CORPORATION, DBA)	
AVISTA UTILITIES,)	
)	
Respondent.)	
_____)	

RESPONSE TESTIMONY OF ROBERT R. STEPHENS
ON BEHALF OF
THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

July 22, 2014

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1 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

2 **A.** Robert R. Stephens. My business address is 16690 Swingley Ridge Road, Suite 140,
3 Chesterfield, MO 63017.

4 **Q. WHAT IS YOUR OCCUPATION?**

5 **A.** I am a consultant in the field of public utility regulation and a Principal of Brubaker &
6 Associates, Inc., energy, economic and regulatory consultants.

7 **Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND**
8 **EXPERIENCE.**

9 **A.** These are set forth in Exhibit No. ___(RRS-2).

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

11 **A.** I am appearing on behalf of the Industrial Customers of Northwest Utilities (“ICNU”),
12 an association of large industrial businesses, some of whom are customers of Avista
13 Corporation (“Avista” or the “Company”).

14 **Q. WHAT IS THE PURPOSE OF YOUR RESPONSE TESTIMONY?**

15 **A.** I will address Avista’s electric cost of service study, revenue allocation (“rate
16 spread”), and rate design issues. More specifically, with respect to cost of service, I
17 will address alternatives to Avista’s allocators for production-related costs and for
18 transmission costs. I will also address Avista’s rate spread proposal for a uniform
19 percentage increase to the rate schedules, and its proposals for rate design, including
20 Avista’s decoupling proposal.

21 The fact that I do not address any particular issue should not be interpreted as
22 tacit approval of any position taken by Avista.

1 **I. SUMMARY**

2 **Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.**

3 **A.** My response testimony can be summarized as follows:

- 4 1. The Company’s electric cost of service study filed in this case is, in many respects,
5 consistent with studies filed by Avista in the past. However, I have identified two
6 significant changes that should be made in order for the cost of service study to
7 more accurately measure the cost causation incurred by the various customer rate
8 schedules. These relate to the classification and allocation of production costs and
9 the allocation of transmission costs.
- 10 2. With respect to the classification and allocation of production plant costs, I discuss
11 the significant shortcomings of the “Peak Credit” classification and recommend
12 that it be discontinued. My recommendation is for production fixed costs to be
13 allocated in a more traditional demand approach. If the Washington Utilities and
14 Transportation Commission (the “Commission”) decides to retain the Peak Credit
15 classification approach, I strongly recommend that the demand allocator be
16 modified to more accurately address capacity cost causation.
- 17 3. Whether or not the Peak Credit is retained, I recommend use of the 4 Coincident
18 Peaks (“CP”) as a better measure of the demand component for allocating
19 production costs than Avista’s proposed 12 CP measure, since Avista’s load
20 exhibits significant peaks. This allocator is also more strongly supported in the
21 National Association of Regulatory Utility Commissioners (“NARUC”) Electric
22 Utility Cost Allocation Manual (“NARUC Manual”).
- 23 4. With respect to transmission system costs, I recommend use of the 12 CP demand
24 allocation method rather than the Peak Credit method. 12 CP is a better measure
25 of cost causation and is more consistent with industry norms.
- 26 5. Adjustment on these two allocation issues reveals significant class cost differences
27 from the results of the Avista cost study. The differences are summarized and
28 shown for each class rate schedule herein.
- 29 6. Regarding rate spread, I support Avista’s proposed uniform percentage increase, if
30 Avista’s full revenue requirement is approved. If Avista does not receive its
31 requested revenue requirement, then the reduction should flow to the rate
32 schedules other than Schedule 1, since it is currently paying revenues well below
33 its cost of service.
- 34 7. I do not support Avista’s proposal for revenue decoupling for Schedule 25.
35 Nevertheless, if the Commission adopts some form of adjustment, a better
36 approach to provide revenue stabilization would be through increasing the demand
37 charges, offset by decreased energy charges.

1 **II. ELECTRIC COST OF SERVICE STUDY**

2 **Overview**

3 **Q. PLEASE EXPLAIN THE BASIC STEPS FOR ESTABLISHMENT OF FAIR**
4 **AND REASONABLE RATES?**

5 **A.** The ratemaking process has three steps. First, we must determine the utility’s total
6 revenue requirement and whether an increase or decrease in revenues is necessary.
7 Second, we must determine how the revenues are to be distributed among the various
8 customer classes or schedules. A determination of how many dollars of revenue
9 should be produced by each class is essential to obtaining the appropriate level of
10 rates. This is called “revenue allocation” or “rate spread.” Finally, individual tariffs
11 must be designed to produce the required amount of revenues from each class of
12 service and to send efficient price signals to customers.

13 The guiding principle at each step should be cost of service. In the first step –
14 determining revenue requirements – it is widely agreed that the utility is entitled to a
15 revenue increase only to the extent that its actual overall cost of service has increased.
16 If current rate levels exceed the revenue requirement, a rate reduction is required. In
17 short, rate revenues should equal a utility’s actual cost of service. The same principle
18 should apply in the last two steps. Each customer class should, to the extent
19 practicable, produce revenues equal to the cost of serving that particular class. On
20 some occasions, this may require a rate increase for some customer classes and a rate
21 decrease for others. The standard tool for determining whether a class requires a rate
22 increase or decrease is an embedded class cost of service (“ECOS”) study, which
23 shows the rate of return for each class of service. Ideally, rate levels should be
24 modified so that each customer class provides approximately the same rate of return.

1 Finally, in designing individual tariffs, the goal is to base the rate design on the
2 cost of service, so that each customer's rate tracks, to the extent practicable, the
3 utility's cost of providing that service to the customers on the tariff.

4 **Q. HOW ARE LARGE INDUSTRIAL CUSTOMERS AFFECTED BY THE**
5 **PRICE OF ENERGY?**

6 **A.** For many industrial customers, energy is a primary component of their costs. For
7 some, it may be the most critical component. As such, rate stability and overall cost of
8 electricity prices are vital to the economic health of large commercial and industrial
9 customers in Washington – and to the economic health of Washington itself, as
10 Washington industries compete in national and world markets. Furthermore, any cost
11 of service study or rate design that misallocates costs to large customers will also
12 result in unjust and unreasonable rates.

13 **Q. WHAT IS THE BASIC PURPOSE OF AN ECOS STUDY?**

14 **A.** The basic purpose of an ECOS study is an empirical determination of the cost of
15 serving classes of customers.

16 After determining the overall cost of service or revenue requirement, an ECOS
17 study is used to ascertain the cost of service among customer classes (i.e., a cost of
18 service study shows how each customer class contributes to the total system cost). For
19 example, when a class produces the same rate of return as the total system, it is
20 returning to the utility revenues sufficient to cover the costs incurred in serving it
21 (including a reasonable authorized return on investment). If a class produces a below-
22 average rate of return, it may be concluded that the revenues are insufficient to cover
23 all relevant costs. On the other hand, if a class produces a rate of return above the
24 average, it is paying revenues sufficient to cover the cost attributable to it and, in

1 addition, is paying part of the cost attributable to other classes who produce a below
2 average rate of return. The ECOS study is important because it shows the class
3 revenue requirement as well as the rate of return under current and any proposed rates.

4 As a measurement or estimation tool, the ECOS study is not the step in which
5 other factors, such as rate moderation or continuity, should be considered or allowed
6 to influence the results. Those types of considerations are taken up in the revenue
7 allocation and rate design steps.

8 **Q. PLEASE COMMENT ON THE PROPER FUNDAMENTALS OF AN ECOS**
9 **STUDY.**

10 **A.** In all ECOS studies, certain fundamental concepts should be recognized. Of primary
11 importance among these concepts is the functionalization of costs, as well as the
12 classification of the nature of these costs as to whether they vary with the quantity of
13 energy consumed, the demand placed upon the system, or the number of customers
14 being served. Stated another way, functionalization is the classification and
15 arrangement of costs according to major functions, such as production, transmission,
16 and distribution.

17 Fixed costs are those costs which tend to remain constant over the short run
18 irrespective of changes in output and are generally considered to be demand-related.
19 Fixed costs include those costs which are a function of the size of the investment in
20 utility facilities, and those costs necessary to keep the facilities “on-line.” Variable
21 costs, on the other hand, are those costs which tend to vary with output and are
22 generally considered to be commodity-related. Customer-related costs are those
23 which are closely related to the number of customers served, rather than the quantity
24 of energy consumed or the peak demands placed upon the system. An understanding

1 of these concepts is essential to development of ECOS studies, as well as appropriate
2 rate design.

3 **Review of Avista's Cost of Service Study**

4 **Q. HAVE YOU REVIEWED THE COMPANY'S ECOS STUDY?**

5 **A.** Yes. I have reviewed the Company's ECOS study that was submitted as part of
6 Avista witness Tara Knox's direct testimony in this case.^{1/}

7 **Q. IS THE COMPANY'S ECOS STUDY REASONABLE TO USE AS A BASIS**
8 **FOR REVENUE ALLOCATION AND RATE DESIGN IN THIS CASE?**

9 **A.** Not entirely. The ECOS study filed in this case is, in many respects, consistent with
10 studies filed by Avista in the past and is reasonable in certain ways. However, I have
11 serious concerns with two aspects of its study. First, the study classifies production
12 plant investment to the customer classes using a method that is based only in small
13 part (31%) on the customers' contribution to peak demand for each month of the year
14 and in much larger part (69%) on the basis of energy.^{2/}

15 This method is improper because the allocated plant investments include the
16 cost of all production resources, and are dependent on the maximum capacities of
17 those resources. Instead, production costs should be allocated to the customer classes
18 according to each class's demand during the peak months, when all of Avista's
19 production resources are in use, and when those resources are most likely to be
20 operating at their maximum capacities. It is Avista's system peak demands, which
21 occur during winter and summer months, that drive the need for additional capacity.
22 Demands during moderate-load times, whether time of day or month of year, do not

^{1/} Exh. No. ____ (TLK-1T).

^{2/} Id. at 15.

1 cause new generating capacity to be built. Energy allocators should be used only on
2 variable costs, i.e., those which vary with the level of output of the units, such as fuel.

3 Second, in addition to its misallocation of production costs, the Company's
4 ECOS study also improperly allocates the costs of transmission.

5 **Allocation of Production-Related Costs**

6 **Q. HOW HAS THE COMPANY ALLOCATED PRODUCTION-RELATED**
7 **COSTS?**

8 **A.** The Company's process is described at pages 12-15 of Avista witness Knox's direct
9 testimony, and in additional detail at pages 3-4 of Exhibit No. ____ (TLK-3).

10 As described, Avista proposes to use the "Peak Credit" ratio to classify
11 production and transmission resources. According to Ms. Knox, Avista proposes a
12 modification to a prior application of the Peak Credit measure, used prior to 2010, to
13 one which utilizes the system load factor to determine the proportion of the production
14 function that is demand-related. This modification yields a 31.27% proportion to be
15 allocated on the basis of demand, with the remaining 68.73% to be allocated based on
16 energy delivered. Avista performs this classification for both production fixed and
17 variable costs and, as described below, to transmission plant. For the approximately
18 31% of costs that are classified as demand-related, Avista proposes to allocate on the
19 basis of 12 CP, based on the average class contributions to the 12 monthly peaks for
20 the year ended June 30, 2013.

21 **Q. SETTING ASIDE THE VALIDITY OF THE PEAK CREDIT FOR THE**
22 **MOMENT, WHY HAS AVISTA USED THE 12 CP METHOD TO ALLOCATE**
23 **THE PRODUCTION COSTS IN ITS ECOS STUDY?**

24 **A.** Avista witness Knox states as follows:

1 Although the Company is usually a winter peaking utility, it
2 experiences high summer peaks and careful management of capacity
3 requirements is required throughout the year. The use of the average of
4 twelve monthly peaks recognizes that customer capacity needs are not
5 limited to the heating season.^{3/}

6 **Q. DO YOU FIND THIS EXPLANATION COMPELLING?**

7 **A.** No, I do not. As I will explain further, Avista demonstrates significant peaks,
8 especially in the winter; although in 2012, Avista experienced two high demand
9 months in the summer (which are included in the test year). A 12 CP method is more
10 typically used when demands are relatively steady over the course of a year and do not
11 exhibit significant peaks, which drive the need for new capacity. In addition, when 12
12 CP is used, it is typically when all production plant costs are allocated on the basis of
13 demand, rather than when only a relatively small proportion (31%) is allocated on
14 demand.

15 **Q. IS AVISTA’S USE OF 12 CP IN THIS MANNER WELL SUPPORTED IN**
16 **INDUSTRY LITERATURE, SUCH AS THE NARUC MANUAL?**

17 **A.** No. Although I have not conducted an exhaustive search for corroboration of Avista’s
18 method in industry literature, thus far, I have seen no specific support for the method.
19 Rather, I find greater support for a more direct measure of system peak in the NARUC
20 Manual, which lists the 12 CP method as one of the options for production allocation,
21 but not in conjunction with a Peak Credit classification approach.

22 However, the same passage of the NARUC Manual that addresses the 12 CP
23 method casts doubt on its use for Avista, when it states of the 12 CP method: “This
24 method is usually used when the monthly peaks lie within a narrow range; i.e., when

^{3/} Exh. No. ____ (TLK-3T) at 3.

1 the annual load shape is not spiky.”^{4/} While the NARUC Manual does not define the
2 word “spiky,” it is clear that in cases where the need for production capacity (i.e.,
3 system demand) is substantially different across the months of the year, a 12 CP
4 allocator is not appropriate.

5 Additional guidance is provided in the NARUC Manual where it describes
6 conditions wherein multiple coincident peak demands may be warranted. In
7 describing one of those conditions, the NARUC Manual states: “Criteria for
8 determining which hours to use include: (1) all hours of the year with demands within
9 5 percent or 10 percent of the system’s peak demand.”^{5/}

10 By considering only the hourly demands that are reasonably close to the annual
11 system peak, the cost analyst recognizes that it is only during the highest system load
12 hours that production capacity is most likely to be fully utilized. Consequently, a
13 demand allocation method that is based on each class’s contribution during these high
14 demand periods will fairly and reasonably recognize the classes’ proportionate
15 responsibility in causing the utility to incur those production investments. Therefore,
16 in cases where the monthly peak loads fluctuate significantly (e.g., like the nearly 38%
17 fluctuation in peak load in Avista’s case),^{6/} a method that considers only the annual
18 system peak, or the average of monthly peaks that are near the system peak, is more
19 appropriate.

20 Another instructive allocation method from the NARUC Manual is the
21 “summer and winter peak method” which is used to “reflect the effect of two distinct

^{4/} NARUC Manual at 46.

^{5/} Id. (emphasis added).

^{6/} The highest peak month, July, is nearly 38% higher than the lowest peak month, September.

1 seasonal peaks on customer cost assignment.”^{7/} The NARUC Manual states: “If the
2 summer and winter peaks are close in value, and if both significantly affect the
3 utility’s generation expansion planning, this approach may be appropriate.”^{8/}

4 As I will demonstrate below, during the test year, Avista exhibited the summer
5 and winter peak conditions described above. Under the summer and winter peak
6 method, either the single highest summer and single highest winter peaks are used
7 (i.e., 2 CP) or a small number of summer and winter peak hours are used (i.e., 4 CP).

8 To summarize, when monthly peak demands are quite similar during the entire
9 year, a 12 CP method may be supported by industry literature. But when, as here, a
10 substantial variation in peak demands is seen throughout the year, there is more
11 support for production plant allocation based only on those peaks within a narrow
12 range of the highest peak, or on the summer and winter peaks only.

13 **Q. WHY ARE THE CUSTOMER LOADS DURING THE HIGHEST MONTHLY**
14 **PEAK DEMANDS RELEVANT TO THE ALLOCATION OF PRODUCTION**
15 **INVESTMENT?**

16 **A.** The key factors that link customer loads at the time of the highest monthly peak
17 demand to the allocation of production investments are the following:

- 18 1. Utilities typically bring all of their generating resources into operation in the hours
19 leading up to their highest monthly peaks. This includes the base load,
20 intermediate load and peaking plants, as well as the short-term and long-term
21 power purchasing contracts. For many utilities in the United States, these peaks
22 occur during the summer season. Avista exhibits peaks in both summer and
23 winter.
- 24 2. The production costs that are allocated include the cost of base load, intermediate
25 load and peaking plants, as well as the costs of short-term and long-term power
26 purchase contracts.

^{7/} *NARUC Manual* at 45.

^{8/} Id.

1 3. The portion of the utility's highest monthly demand that is contributed by a
2 customer class will provide a fair representation of the portion of production cost
3 that the utility incurred to serve the class. For example, if a class constitutes 10%
4 of the load at the times of system peak, it essentially represents 10% of the need
5 for generation capacity and, thus, should be allocated 10% of production capacity
6 costs.

7 **Q. HAVE YOU HAD AN OPPORTUNITY TO REVIEW AVISTA'S**
8 **HISTORICAL SYSTEM PEAK LOAD DATA?**

9 **A.** Yes. These load data are available in Avista's annual Federal Energy Regulatory
10 Commission ("FERC") Form 1 filings. Charts of the historical load data for the last
11 six calendar years are shown on Exhibit ____ (RRS-3). These charts clearly indicate a
12 dominant winter peak and, in 2012 (only), two high summer peak months. In 2013,
13 only the monthly peak demands during January and July were within 10% of the
14 December peak.^{9/}

15 Table 1, below, summarizes the number of months in each of the last six
16 calendar years that were within 5% and 10% of the system peak.

^{9/} In Exh. No. ____ (RRS-3), months within 5% of the peak (inclusive) are shown in red and months between 5% and 10% lower than the peak are shown in gray.

TABLE 1		
<u>Number of Months In Which Peak Demands Were Near Annual Peak Demands</u>		
<u>Year</u>	<u>Within 5% of Peak</u>	<u>Within 10% of Peak</u>
2008	0	1
2009	1	2
2010	0	3
2011	1	3
2012	2	5
2013	0	2
Test Year	2	4

1 As can be seen from Table 1, Avista has peak demands that are within 10% of
2 the system peak in relatively few months each year, and even fewer are within 5% of
3 the peak.

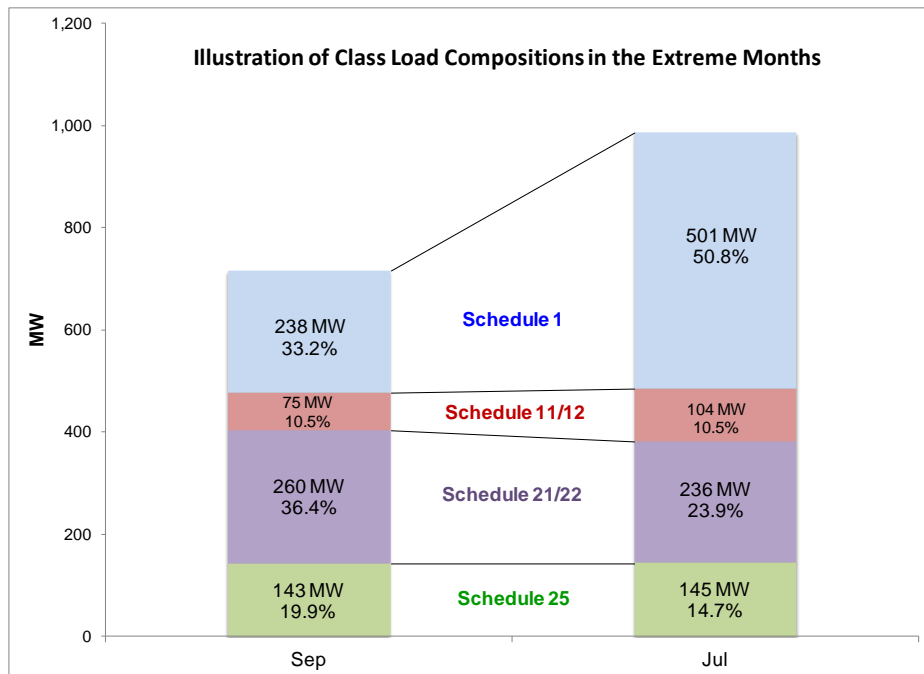
4 Based on the excerpt from the NARUC Manual regarding the selection of
5 multiple coincident peaks, applied to the test year peak data, a 3 CP allocation method
6 would reflect the number of monthly peaks within 5% of the annual peak (inclusive).
7 A 5 CP allocation method would reflect the number of monthly peaks within 10% of
8 the annual peak (inclusive). However, 2013 is somewhat anomalous as it actually had
9 no months within 5% of the peak and only two months within 10%. A 4 CP allocator,
10 which is often supported for allocating fixed production costs, would be reasonable (if
11 not conservative) in this case. A 4 CP allocator would include July, August,
12 December and January and, thus, would also match and equally represent the summer
13 and winter peaks exhibited by Avista’s customers. This allocation method finds
14 greater support in the NARUC Manual than does the 12 CP methodology used by
15 Avista, as discussed previously.

1 The Company's peak demands during the other months are forecast to be
2 significantly lower than those that occur during the summer and winter peak months.
3 Therefore, in my opinion and based on the criteria stated in the NARUC Manual, the
4 12 CP method simply is not justified as the best demand allocator for the Avista
5 system, and a 4 CP method should be used.

6 **Q. CAN YOU ILLUSTRATE THE DIFFERING CUSTOMER PROPORTIONS
7 OF SYSTEM LOAD DURING PEAK MONTHS, AS OPPOSED TO
8 NON-PEAK MONTHS?**

9 **A.** Yes. Figure 1 below shows the major Avista customer schedules' contribution to peak
10 load during the Company's extreme (i.e., highest and lowest), demand months of July
11 and September, when its test year system loads are at the maximum and minimum,
12 respectively.

Figure 1



13 As can be seen from Figure 1, peak loads of Schedule 1 and Schedule 11/12
14 customer classes are much higher in July than in September, undoubtedly due

1 primarily to air conditioning, while Schedules 21/22 and 25 are relatively
2 unchanged/flat, in July and September. It is these additional loads of the Schedule 1
3 and Schedule 11/12 customers that drive the peak loads of Avista and the need for
4 generating capacity.

5 **Q. PLEASE COMMENT ON THE PEAK CREDIT METHOD OF**
6 **CLASSIFICATION OF PRODUCTION COSTS.**

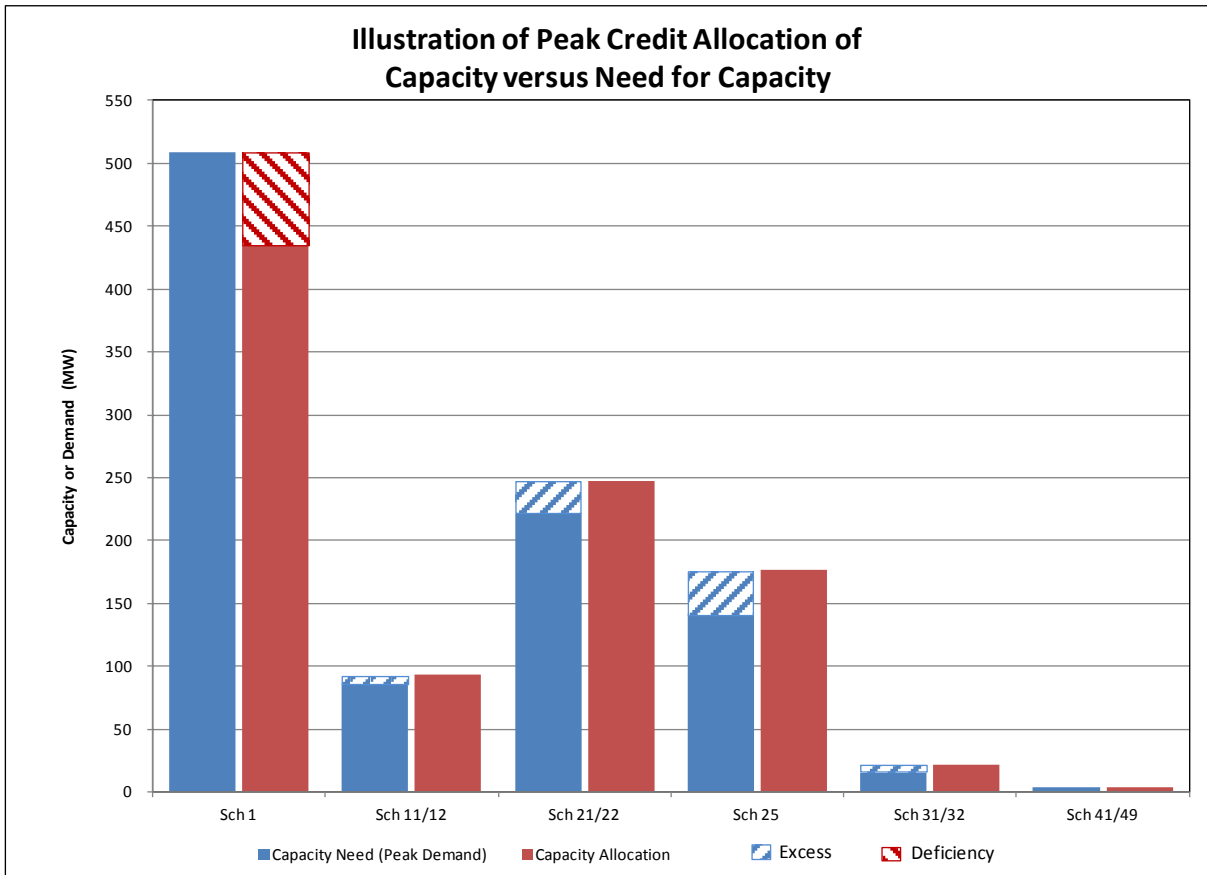
7 **A.** I do not agree with the Peak Credit method used to classify production costs between
8 demand and energy components, as proposed by Avista. This approach is more
9 commonly referred to as the “peak and average demand” method and is given little
10 discussion in the NARUC Manual. While I do not have the complete history of its use
11 in Avista cases, typically the use of this type of method for classification or allocation
12 of production costs is based on a perceived trade-off between capacity investment and
13 fuel savings. In my opinion, this classification inappropriately assigns far too much
14 weight to energy usage as a basis for assigning production costs.

15 In considering how Avista classifies and allocates production plant, and
16 considering the peak demands of the various rate schedules, it is clear that not enough
17 production capacity is assigned to some of the rate schedules and too much is
18 allocated to others. This is illustrated in Exhibit No. ____ (RRS-4) which shows the
19 equivalent amount of capacity allocated to customer rate schedules, as compared to
20 their peak demands.^{10/} As shown in this exhibit, Schedule 25 is allocated considerably
21 more capacity than its peak demand warrants, while Schedule 1, for example, is not
22 assigned enough capacity to meet its capacity needs. Figure 1 below graphically

^{10/} For peak demands, I have utilized the average of the 4 CP, as discussed above. Had I used the actual peak or the single CP, the results shown would have been even more dramatic.

1 depicts the results of Exhibit No. ___(RRS-4). This highlights a major weakness of
2 the Peak Credit method.

Figure 2



3
4 **Q. WHAT CLASSIFICATION OR ALLOCATION METHODOLOGY DO YOU**
5 **RECOMMEND FOR PRODUCTION INVESTMENT IN THIS CASE?**

6 **A.** Because production investment is primarily due to the need for and the size of the
7 peak demands of customers, it should be assigned to customer classes exclusively, or
8 at least primarily, on those classes' contribution to utility system peaks. Allocation by
9 this method has widespread support in the industry and is, in my view, a better
10 reflection of cost causation than allocation methods that utilize energy usage to any
11 significant degree. Furthermore, even when energy usage (as measured by average

1 demand) is utilized, a far more appropriate and typical approach is the “average and
2 excess demand” method.^{11/}

3 However, I am advised that the Peak Credit method has been used for Avista
4 for some time. Assuming the Commission is not constrained to utilize the peak credit
5 method due to its prior use, I recommend it not be used in this case. On the other
6 hand, if the Commission is constrained to utilize the peak credit method, I recommend
7 that it be refined in its application.

8 **Q. IF THE PEAK CREDIT CLASSIFICATION IS ADOPTED, HOW WOULD**
9 **YOU RECOMMEND THAT THE APPROACH BE REFINED?**

10 **A.** In that case, the heavy reliance on energy usage in assigning costs (69%) highlights
11 the critical need to refine the demand allocator used for capacity costs. As mentioned,
12 the Avista electric system exhibits a predominant winter peak and, recently, summer
13 peak. Therefore, any method of cost allocation that considers loads in hours that do
14 not contribute to the need for new generation, or any energy-based method,^{12/} does not
15 adequately account for the dominant system peaks, fails to reflect the actual load
16 characteristics of the Avista system, and fails to properly reflect class responsibility
17 for production investment. Thus, for Avista, a 4 CP is a more appropriate allocation
18 method for demand-related production costs. This is true in the context of a full
19 allocation of production investment or as used in conjunction with the Peak Credit
20 classification approach.

^{11/} See *NARUC Manual* at 49-52.

^{12/} Similarly, allocating costs on average demand is mathematically equivalent to a kWh allocation and ignores the distinctions between peak period usage and off-peak period usage.

1 **Q. HAVE YOU CALCULATED THE 4 CP ALLOCATION FACTORS**
2 **NECESSARY TO APPROPRIATELY ALLOCATE DEMAND-RELATED**
3 **PRODUCTION COSTS IN AVISTA’S ECOS STUDY?**

4 **A.** Yes. These allocation factors, along with Avista’s proposed 12 CP allocation factors,
5 are shown in Table 2, for each of the Avista rate schedules in the ECOS study, and
6 allow for ready comparison across the allocation methods.

<u>Class</u>	<u>4 CP</u>	<u>12 CP</u>
Sch 1	51.99%	48.71%
Sch 11/12	8.83%	8.38%
Sch 21/22	22.65%	24.40%
Sch 25	14.50%	16.27%
Sch 31/32	1.69%	1.97%
Sch 41/49	0.33%	0.27%
Total	100.00%	100.00%

7 **Q. HAVE YOU MODIFIED THE AVISTA ECOS STUDY SO THAT**
8 **PRODUCTION-RELATED COSTS ARE ALLOCATED USING YOUR**
9 **RECOMMENDED 4 CP RATHER THAN THE 12 CP METHOD?**

10 **A.** Yes. I have calculated the ECOS study for the recommended 4 CP demand allocation
11 method under both a 100% demand allocation of production capacity costs, and in the
12 context of Avista’s Peak Credit classification (31% demand, 69% energy). For the
13 100% demand 4 CP allocation, I calculate the ECOS results if the peak credit method
14 for classification is not used at all and, instead, production fixed costs are allocated on
15 the basis of 4 CP demand alone. Disuse of the peak credit method altogether will
16 require some modifications to the allocation of production variable costs and
17 transmission costs. For simplicity, I have used a 100% energy allocator for variable

1 production costs, and a 100% 12 CP allocator for transmission costs. This treatment
2 of transmission costs will be discussed further in the next section. The results of this
3 allocation method are shown in Exhibit No. ____ (RRS-5). As shown, for some rate
4 schedules, the change in production cost allocator makes a significant difference in the
5 cost of service.

6 I have also modified the Avista ECOS study to adopt a 4 CP demand measure
7 in the context of the Peak Credit classification approach, should the Commission
8 utilize that method. For this version of the ECOS study no other changes were made
9 as compared to Avista's proposed study. The results of this modification are shown in
10 Exhibit No. ____ (RRS-6). As with my primary recalculation shown in Exhibit No.
11 ____ (RRS-5), the change in the demand measure makes a significant difference in the
12 schedules' overall cost of service.

13 **Q. ARE THERE OTHER METHODOLOGIES TO CONSIDER HERE?**

14 **A.** Potentially, other parties may recommend a new look at the methodologies used in
15 allocating costs among customer classes. I will review those and comment in the
16 cross-answering testimony.

17 **Q. SHOULD THE COMMISSION RETAIN PRODUCTION COSTS, IS EXHIBIT**
18 **____ (RRS-6) YOUR RECOMMENDED ECOS STUDY RESULT?**

19 **A.** No, not quite. I do not recommend that transmission costs be classified according to
20 the peak credit method under any circumstance, as I will discuss below.

21 **Allocation of Transmission Costs**

22 **Q. HOW DOES AVISTA ALLOCATE TRANSMISSION COSTS IN ITS ECOS**
23 **STUDY?**

24 **A.** It uses the same peak credit methodology as is used for classifying production costs.

1 **Q. WHAT IS THE COMPANY’S RATIONALE FOR ALLOCATING**
2 **TRANSMISSION COSTS IN THIS MANNER?**

3 **A.** My review of Company witness Knox’s direct testimony in this case reveals very little
4 support for this method. First, Ms. Knox states: “In Washington, transmission costs
5 have traditionally been treated as an extension of the generation system, therefore, the
6 revised peak credit ratio has also been applied to transmission costs in this study.”^{13/}

7 Ms. Knox also states:

8 The Peak Credit method acknowledges that all energy production costs
9 contain both capacity and energy components as they provide energy
10 throughout the year as well as capacity during system peaks. Likewise,
11 the transmission system is built not only for peak use, but also for
12 everyday delivery of energy.^{14/}

13 **Q. HOW DO YOU RESPOND TO MS. KNOX’S STATED RATIONALE IN THIS**
14 **REGARD?**

15 **A.** I do not believe it is sufficient to justify this unusual allocation of transmission costs.

16 **Q. WHY DO YOU BELIEVE THIS ALLOCATION METHOD IS UNUSUAL?**

17 **A.** I am not aware of any case outside of Washington where a utility has classified or
18 allocated transmission costs on the basis of energy to any degree. I see no justification
19 for allocating transmission costs in this manner.

20 **Q. WHY DO YOU BELIEVE THERE IS NO JUSTIFICATION FOR UTILIZING**
21 **AN ENERGY COMPONENT IN CLASSIFYING OR ALLOCATING**
22 **TRANSMISSION COSTS?**

23 **A.** Unlike production, where parties sometimes claim there is a trade-off between fixed
24 and variable costs that justify an energy component in the allocation to reflect
25 cost-causation, there is not even an arguable trade-off for transmission facilities.

^{13/} Exh. No. ___(TLK-1T) at 14.

^{14/} Exh. No. ___(TLK-3) at 3.

1 I can illustrate this through a simple hypothetical. If a utility were to build a
2 1,000 MW generating unit in an area that is not adjacent to transmission facilities,
3 additional transmission facilities would need to be constructed to connect the
4 generating unit to the electrical grid. The capacity of the new transmission facilities
5 would need to be designed to carry the maximum output of the generating unit. The
6 capacity of those new transmission facilities is not dependent on the fuel type or
7 economics of the generating unit being constructed or how often it is run. Said
8 another way, essentially the same transmission facilities would need to be built
9 whether the 1,000 MW unit is a nuclear power plant, with a very high capacity factor
10 producing 7.9 million MWh/year, or a natural gas-fired peaking plant with a much
11 lower capacity factor producing 4.4 million MWh/year. The transmission facilities
12 would be designed and constructed to meet the maximum capacity (1,000 MW)
13 required over the lines.

14 Similarly, increased or decreased utilization of the transmission system, once it
15 is built, does not impact the costs of the transmission assets. For example, higher
16 cumulative energy flow without an increase in demand does not impact transmission
17 costs. In addition, the vast majority of transmission costs are fixed, not variable. For
18 these reasons, an energy allocation of transmission costs is not justified.

19 **Q. HAS THE COMPANY CONFIRMED THAT ITS TRANSMISSION SYSTEM**
20 **IS CONSTRUCTED TO MEET THE PEAK DEMAND OF ITS CUSTOMERS?**

21 **A.** Yes. Company witness Patrick Ehrbar states exactly that.^{15/} He makes no mention of
22 energy usage as a causal component in this regard. Further, my review of Avista's

^{15/} Exh. No. ___(PDE-1T) at 14.

1 Transmission Planning Standards, Policies and Procedures reveals no reliance on
2 energy flow as a planning criterion.

3 **Q. ARE THERE OTHER REASONS FOR NOT UTILIZING THE PEAK CREDIT**
4 **METHOD FOR ALLOCATING TRANSMISSION COSTS?**

5 **A.** Yes, there are. In providing guidance to utilities in billing for network transmission
6 service, FERC utilizes 12 CP, without regard to the amount of energy flowed across
7 the lines over time.^{16/} Further, in billing for transmission service, Avista itself utilizes
8 a 12 CP billing method for network transmission service as specified in Sections 34.1
9 and 34.2 of Avista's Open Access Transmission Tariff. A copy of Section 34 of that
10 tariff is attached as Exhibit No. ____ (RRS-7).

11 **Q. BESIDES 12 CP, ARE THERE ANY OTHER REASONABLE OPTIONS FOR**
12 **ALLOCATION OF TRANSMISSION COSTS?**

13 **A.** Yes, considering that the transmission system is built to meet the peak demands on the
14 system (as opposed to times of relatively low demands), it would not be unreasonable
15 to use a 1 CP or 4 CP measure given Avista's annual load shape showing some
16 monthly peak demands to be far (38%) below the annual peak. Indeed, some Regional
17 Transmission Organizations effectively use a 1 CP or 5 CP for billing for transmission
18 service. However, although 12 CP may not be the truest measure of cost-causation, as
19 it overemphasizes demands in non-peak seasons, given its widespread use by other
20 utilities around the country and by FERC, it is reasonable (though conservative) for
21 use in this case.

^{16/} Generally, FERC Orders 888 and 889 dealt with these matters.

1 **Q. WHAT IS YOUR RECOMMENDATION?**

2 **A.** I recommend that transmission system costs not utilize the peak credit method at all.
3 Rather, the 12 CP demand measure should be used for 100% allocation of
4 transmission costs.

5 **Q. CAN YOU PROVIDE A COMPARISON OF THE TRANSMISSION**
6 **ALLOCATION FACTORS THAT YOU RECOMMEND TO THOSE USED BY**
7 **AVISTA?**

8 **A.** Yes, I can. The resulting effective transmission allocation factors are shown in Table
9 3.

<u>Rate</u> <u>Schedule</u>	<u>Avista</u> <u>Allocation</u>	<u>ICNU</u> <u>Allocation</u>
Sch 1	44.45%	48.71%
Sch 11/12	9.54%	8.38%
Sch 21/22	25.28%	24.40%
Sch 25	18.08%	16.27%
Sch 31/32	2.25%	1.97%
Sch 41/49	0.40%	0.27%
Total	100.00%	100.00%

10

11 **Q. CAN YOU PROVIDE THE RESULTS OF APPLYING THE 12 CP**
12 **ALLOCATION OF TRANSMISSION COSTS TO THE MODIFIED PEAK**
13 **CREDIT ALLOCATION OF PRODUCTION COSTS?**

14 **A.** Yes. This information is provided in Exhibit ____ (RRS-8). This exhibit differs from
15 Exhibit No. ____ (RRS-6) in that transmission costs are 100% allocated on 12 CP. If
16 the Peak Credit is retained at all, it should only be retained for production costs.

Overall Cost of Service Results

Q. CAN YOU PLEASE PROVIDE A SUMMARY OF THE RESULTS OF THE ECOS STUDIES MODIFIED FOR BOTH OF YOUR RECOMMENDATIONS FOR PRODUCTION COST ALLOCATION AS WELL AS TRANSMISSION COST ALLOCATION?

A. Yes. This information is provided in Table 4, below, which provides the rate schedule returns under Avista’s ECOS study, my preferred ECOS study, Exhibit No. ____ (RRS-5) and the modified Peak Credit (production-only) ECOS study, Exhibit No. ____ (RRS-8).

TABLE 4						
<u>Summary Comparison of Cost of Service Study Results</u>						
<u>Schedule</u>	<u>Avista ECOS Study</u>		<u>Exhibit (RRS-5) Recommended ECOS Study</u>		<u>Exhibit (RRS-8) Modified Peak Credit ECOS Study</u>	
	<u>Rate of Return</u>	<u>Index</u>	<u>Rate of Return</u>	<u>Index</u>	<u>Rate of Return</u>	<u>Index</u>
Sch 1	4.50%	0.65	3.92%	0.57	4.09%	0.59
Sch 11/12	13.19%	1.92	13.77%	2.00	13.38%	1.94
Sch 21/22	9.41%	1.37	10.14%	1.47	9.83%	1.43
Sch 25	5.86%	0.85	7.57%	1.10	6.85%	0.99
Sch 31/32	6.28%	0.91	7.56%	1.10	7.02%	1.02
Sch 41/49	6.36%	0.92	6.50%	0.95	6.40%	0.93
Total	6.88%	1.00	6.88%	1.00	6.88%	1.00
Notes:						
Production (fixed)	12 CP Peak Credit		4 CP 100%		4 CP Peak Credit	
Production (variable)	12 CP Peak Credit		Generation 100%		4 CP Peak Credit	
Transmission	12 CP Peak Credit		12 CP 100%		12 CP 100%	

As Table 4 shows, the cost returns vary significantly from Avista’s calculation.

For example, rather than a rate of return index of 0.85 for Schedule 25, under my

1 adjusted measure of cost of service, the rate of return index is 1.10, meaning that
2 Schedule 25 customers actually are providing revenues to produce a return higher than
3 the system average, i.e., indicating that Schedule 25 is currently providing revenues
4 above cost of service.

5 III. ELECTRIC REVENUE ALLOCATION (“RATE SPREAD”)

6 **Q. PLEASE DISTINGUISH THE REVENUE ALLOCATION STEP IN THE**
7 **PROCESS FROM THE COST OF SERVICE ANALYSIS.**

8 **A.** As previously mentioned, the cost of service analysis is an empirical analysis of the
9 costs caused by the various customer schedules. In itself, it does nothing to change
10 customers’ rates. Rather, determining how much of the revenue requirement should
11 be borne by each rate schedule is the step known as revenue allocation or rate spread.

12 The rate spread should be based on the results of the cost of service study,
13 since cost-based rates tend to be the most economically efficient. However, the rate
14 spread can be influenced by other principles, such as rate continuity, rate moderation
15 and avoidance of rate shock.

16 **Q. WHAT IS AVISTA’S PROPOSAL REGARDING RATE SPREAD?**

17 **A.** As explained by Company witness Patrick Ehrbar, Avista proposes to spread its
18 increase on a uniform percentage basis to all classes.^{17/} Mr. Ehrbar’s rationale for this
19 rate spread approach is primarily found in his consideration of the cost of service
20 study from the 2012 general rate case, where he concludes:

21 Those study results along with the cost of service study results in this
22 case demonstrate that all rate schedules, with the exception of the Street
23 and Area Lights rate schedules, have had steady movement closer to
24 the overall rate of return (unity). Therefore, the Company chose to

^{17/} Exh. No. ___(PDE-1T) at 5.

1 spread the proposed rate increase on a uniform percentage basis which
2 continues the progress towards unity.^{18/}

3 **Q. IS AVISTA’S PROPOSAL REASONABLE?**

4 **A.** It is clear from his statement that Mr. Ehrbar’s proposal is based on the results of
5 Avista’s cost of service study showing that certain classes to varying degrees are
6 currently over-paying or under-paying, as evidenced by the present relative rate of
7 return, as shown on Table 6 of Mr. Ehrbar’s direct testimony.^{19/} I can accept Mr.
8 Ehrbar’s proposal at Avista’s proposed revenue requirement.

9 However, even Mr. Ehrbar’s proposal provides very little movement toward
10 cost of service for Schedule 1, which is far below cost of service under any of the
11 ECOS study results shown in Table 4 above. This is indicated by the rate of return
12 indices which range from 0.57 to 0.65. Greater movement toward cost of service for
13 this class is justified from a cost of service view. Mr. Ehrbar’s proposed 3.8%
14 increase does little to bring Schedule 1 closer to cost. Even with a 3.8% increase,
15 Schedule 1 would provide rate of return indices of only 0.60 under my recommended
16 ECOS study and 0.68 under Avista’s ECOS study.^{20/}

17 **Q. WHAT DO YOU RECOMMEND FOR RATE SPREAD?**

18 **A.** Although a greater than 3.8% increase is justified from a cost of service basis, it is
19 acceptable in this case. However, the increase for Schedule 1 should not be reduced if
20 Avista’s approved revenue requirement is lower than proposed by Avista. Rather,
21 those savings should accrue to the other classes, all of which are providing revenues
22 near or above cost of service presently.

^{18/} Id. at 10.

^{19/} Id. at 11.

^{20/} Based on my recommended ECOS study.

1 **IV. ELECTRIC RATE DESIGN**

2 **Q. WHAT IS AVISTA’S OVERALL PROPOSAL AS IT RELATES TO RATE**
3 **DESIGN?**

4 **A.** According to Company witness Ehrbar, the Company is not proposing any changes to
5 the existing rate structures within its rate schedules except for changes in rate
6 components.^{21/}

7 For Extra Large General Service Schedule 25, the current rate consists of a
8 two-tiered demand charge: (1) \$15,000 for the first 3,000 kVA or less; and (2) an
9 additional demand charge of \$5.25 per kVA for monthly demand in excess of 3,000
10 kVA. Energy charges are broken into three blocks: the first 500,000 kWh, 500,00
11 through 6,000,000 kWh, and all over 6,000,000 kWh. The rates per kWh are
12 \$0.05750, \$0.05177, and \$0.04433, respectively. Avista proposes to change the
13 demand charges to \$16,500 for the first 3,000 kVA and \$5.75 per kVA for demand
14 above 3,000 kVA.^{22/} The energy charges for the same blocking structure are proposed
15 to be \$0.05853, \$0.05266, and \$0.04503, respectively. In addition to these demand
16 and energy charges, there are service voltage discounts, which Avista does not
17 propose to change.

18 **Q. DO YOU HAVE ANY RECOMMENDATIONS AS REGARDS SCHEDULE 25**
19 **RATE DESIGN?**

20 **A.** Yes, I do. As indicated in Mr. Ehrbar’s direct testimony, the Company is concerned
21 about revenue stabilization, and Mr. Ehrbar goes so far as to propose a revenue
22 decoupling mechanism, which I will discuss further below. Although I believe the
23 decoupling proposal is unwarranted for Schedule 25 customers, in the case of the

^{21/} Id. at 12.
^{22/} Exh. No. ____ (PDE-4) at 3.

1 Commission choosing to adopt some form of adjustment that works to stabilize
2 revenue, I believe it would be appropriate to increase the Schedule 25 demand charges
3 which, as previously mentioned, are generally used to recover fixed costs. This
4 increase in demand charges would necessitate a reduction in energy charges in order to
5 maintain the overall revenues to be collected from this rate schedule. I will further
6 discuss how this adjustment would help to stabilize revenue.

7 **Q. WHAT IS AVISTA’S PROPOSAL REGARDING REVENUE DECOUPLING?**

8 **A.** Avista is requesting an electric and natural gas decoupling mechanism in this case. I
9 will focus on the electric decoupling mechanism, as described by Mr. Ehrbar:

10 The traditional problem is that rates are established in a general rate
11 case to provide revenue to recover the fixed costs to provide service to
12 customers. However, the majority of that revenue is received on a
13 volumetric basis, i.e., based on the volume of kWh and therm sales. ...
14 [I]f the ratemaking process does not account for the known reduction in
15 kWh sales related to energy efficiency, rates set based on historical test
16 period loads are actually designed to not provide recovery of the
17 Company’s costs under normal operating conditions.^{23/}

18 Avista explains that it seeks a rate mechanism that will provide for greater revenue
19 stability and, at the same time, not discourage energy efficiency efforts by customers.
20 Mr. Ehrbar states: “The primary reason Avista is considering decoupling in the first
21 place is there is recognition that energy efficiency kWh savings eliminates revenue
22 from the utility intended to cover utility costs.”^{24/}

23 Mr. Ehrbar goes on to outline the elements of the electric decoupling
24 mechanism as consisting of four steps.^{25/} Essentially, his proposed method is to
25 determine and fix the allowed non-power supply revenue on a per customer basis.

^{23/} Exh. No. ____ (PDE-1T) at 49-50.

^{24/} Id. at 23.

^{25/} Id. at 54-59.

1 Under this design, as long as the number of customers in each rate schedule stays
2 relatively constant, Avista's revenues that are derived from items that are not power
3 supply related remain relatively constant. Power supply related costs are variable and
4 generally would rise and fall with power supply revenues.

5 **Q. DO YOU HAVE AN OPINION AS TO WHETHER AVISTA'S PROPOSED**
6 **ELECTRIC DECOUPLING MECHANISM SHOULD BE APPROVED?**

7 **A.** As a general matter, I recommend against decoupling mechanisms as unnecessary
8 because they reduce the utility's incentive to minimize costs. Alternatively, sound
9 utility rate designs, i.e., efficient price signals, can often provide the results that the
10 utility seeks.

11 I especially find Avista's decoupling proposal inappropriate in its application
12 to Schedule 25 customers, as being both ill-conceived and unnecessary. This issue is
13 addressed in greater detail by ICNU witness Bradley G. Mullins.

14 **Q. WHY IS THE COMPANY'S PROPOSED ELECTRIC DECOUPLING**
15 **MECHANISM PARTICULARLY INAPPROPRIATE AS IT PERTAINS TO**
16 **SCHEDULE 25 CUSTOMERS?**

17 **A.** First, for Schedule 25, the relatively small number of customers causes the non-power
18 supply revenue per customer to be very large and potentially volatile. This could
19 thwart Avista's goal of stabilizing revenue. Should a Schedule 25 customer shut down
20 (even a small one) it could have a significant impact on the Company's non-power
21 supply revenues. This is not true for other customer classes with much lower per
22 customer revenue levels. An industrial plant closure is a real possibility given the
23 economic climate in eastern Washington and global competition. Customers should
24 not pay increased revenues when energy savings have nothing to do with customers.

1 Second, as I alluded to previously, a much simpler change in the rate design
2 could accomplish much of the revenue stability the Company seeks. By this, I am
3 referring to the shift of some of the cost recovery from the per kWh energy sales to the
4 demand component.

5 **Q. WHY WOULD THIS PROVIDE GREATER REVENUE STABILITY?**

6 **A.** To begin, demand charges are generally established to recover fixed costs of the utility
7 system, such as fixed production, transmission and distribution costs (i.e., those costs
8 that do not vary with the level of energy sales). Thus, as more of the cost recovery is
9 assigned to the demand charges, more revenue is derived to cover these fixed costs.

10 In addition, to the extent customers would implement significant energy
11 efficiency measures, a smaller impact on Avista would be observed because the
12 energy charges are lower.

13 **Q. WHAT IS YOUR SPECIFIC RECOMMENDATION WITH REGARD TO**
14 **AVISTA'S PROPOSED ELECTRIC DECOUPLING MECHANISM?**

15 **A.** Whether or not a decoupling mechanism is approved for any other rate schedule, I
16 recommend that it not be approved for Schedule 25. I believe it would be reasonable
17 to increase the demand charge in the first block from the current \$15,000 to as much
18 as \$25,000 and to increase the per-unit charge for demand over 3,000 kVA from \$5.25
19 per kVA to as much as \$6.25 per kVA. Such a change would provide significant
20 improved revenue stability for Avista, if the Commission finds it necessary to adjust
21 rates in order to increase revenue stability.

22 **Q. WHAT WOULD THE RESULTING ENERGY CHARGES BECOME UNDER**
23 **YOUR ALTERNATE PROPOSAL?**

24 **A.** The energy charges would depend on the overall revenue requirement assigned to the
25 rate class. If the maximum increases to demand charges outlined above were adopted,

1 at Avista's proposed increase to the rate class, the blocked energy charges would
2 become \$0.05556, \$0.04999, and \$0.04274 per kWh, respectively, for the blocks
3 defined by Avista. These figures would change, of course, with any change to the
4 Schedule 25 revenue allocation.

5 These changes should provide greater revenue stability to Avista and would
6 reduce any disincentives it has related to energy efficiency programs for these
7 customers.

8 **Q. DOES THIS CONCLUDE YOUR RESPONSE TESTIMONY?**

9 **A.** Yes, it does.