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UTILITIES COMMISSION

**BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**

IN THE MATTER OF THE APPLICATION ) CASE NO. AVU-E-08-01  
OF AVISTA CORPORATION FOR THE ) CASE NO. AVU-G-08-01  
AUTHORITY TO INCREASE ITS RATES )  
AND CHARGES FOR ELECTRIC AND )  
NATURAL GAS SERVICE TO ELECTRIC ) DIRECT TESTIMONY  
AND NATURAL GAS CUSTOMERS IN THE ) OF  
STATE OF IDAHO ) DENNIS P. VERMILLION  
)

FOR AVISTA CORPORATION

(ELECTRIC AND NATURAL GAS)

1 I. INTRODUCTION

2 Q. Please state your name, employer and business  
3 address.

4 A. My name is Dennis P. Vermillion. I am employed  
5 as the Vice President of Energy Resources by Avista  
6 Corporation located at 1411 East Mission Avenue, Spokane,  
7 Washington.

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

10 A. I received a Bachelor of Science degree in  
11 electrical engineering from Washington State University in  
12 1985. I began working for Avista in 1985 and have held  
13 positions in energy trading, marketing, risk management,  
14 power transmission contracting, resource planning and  
15 coordination and regulatory issues. I was appointed as  
16 President and Chief Operating Officer of Avista Energy in  
17 2001. I was appointed Vice President of Energy Resources  
18 in 2007 at the close of the sale of Avista Energy.

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

21 A. My testimony will provide an overview of Avista's  
22 resource planning and power operations which includes  
23 summaries of the Company's resources, current and future  
24 load and resource position, future resource plans, and a  
25 brief discussion of the Company's decision to join the

1 Chicago Climate Exchange. The next section of my testimony  
2 discusses hydro and thermal project upgrades. This is  
3 followed by the Montana riverbed lease issue, hydro  
4 relicensing issues, mercury abatement at Colstrip, and  
5 Jackson Prairie storage. My testimony concludes with a  
6 discussion of the Company's risk management policy.

7 A table of contents for my testimony is as  
8 follows:

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18  
19 **Q. Are you sponsoring any exhibits?**

20 A. Yes. I am sponsoring Exhibit No. 4, Schedule 1  
21 (Avista's 2007 Electric Integrated Resource Plan), Schedule  
22 2 (Memorandum concerning Montana Riverbed Settlement),  
23 Schedule 3 (Memorandum of Negotiated Settlement Terms), and  
24 Schedule 4 (Avista's Risk Policy).

25

26 **II. AVISTA'S RESOURCE PLANNING AND POWER OPERATIONS**

27 **Q. Would you please provide a brief overview of**  
28 **Avista's power generating resources?**

29 A. Yes. Avista's resource portfolio consists of  
30 diverse assets including hydroelectric generation projects,

1 base-load coal and natural gas-fired thermal generation  
2 facilities, wood waste-fired renewable generation, natural  
3 gas-fired peaking generation projects, long-term contracts  
4 including wind and Mid-Columbia hydroelectric generation,  
5 and market power purchases and exchanges. Avista-owned  
6 generation facilities have a total capability of 1,815 MW,  
7 which includes 54% hydroelectric and 46% thermal resources.

8 Table No. 1 below summarizes the present capability of  
9 Avista's owned generation resources. The Company also has  
10 long-term contractual rights for a total of 166 MW of  
11 capability from the Mid-Columbia generation projects in  
12 2009 that are owned and operated by the Public Utility  
13 Districts of Grant, Chelan and Douglas counties. The  
14 Company has a ten-year contract for 35 MW of wind  
15 generation capability from the Stateline Wind Project. The  
16 Company also receives 100 MW of energy from several  
17 contracts through 2010.

1

**Table No. 1 - Avista Generation**

<b>Company-Owned Projects</b>	<b>MW</b>
Noxon Rapids	541
Cabinet Gorge	261
Post Falls	18
Upper Falls	10
Monroe Street	15
Nine Mile	15
Long Lake	90
Little Falls	36
<b>Total Hydroelectric Generation</b>	<b>986</b>
Colstrip Units 3 and 4	230
Coyote Springs 2	287
Kettle Falls	51
<b>Total Base-Load Thermal Generation</b>	<b>568</b>
Northeast CT	62
Kettle Falls CT	7
Boulder Park	25
Rathdrum CT	167
<b>Total Natural Gas Peaking Generation</b>	<b>261</b>
<b>Total Generation</b>	<b>1,815</b>

2

3           **Q.    Would you please provide an overview of Avista's**  
4 **resource planning and power supply operations?**

5           A.    Yes.    The Company uses a combination of owned and  
6 contracted-for resources to serve its requirements.  
7 Dispatch decisions related to these resources are made by  
8 the power supply section of the Energy Resources  
9 Department.    The Department regularly studies capacity and  
10 energy resource needs.    The Company utilizes short and  
11 medium-term wholesale transactions to balance resources  
12 with load requirements.    Longer-term resource decisions  
13 requiring new resources, upgrading existing resources,

1 demand-side management (DSM), and long-term contract  
2 purchases are generally made in conjunction with the  
3 Company's Integrated Resource Plan (IRP) and Request for  
4 Proposals (RFP) processes.

5 **Q. Please summarize the current load and resource**  
6 **position for the Company.**

7 A. The Company has added a variety of resources to  
8 its portfolio in recent years, including: the second half  
9 of Coyote Springs 2; a ten-year agreement for 35 MW of wind  
10 generation capability (estimated 7.6 aMW); medium-term  
11 purchases of 100 aMW through 2010; the purchase of  
12 approximately 7 aMW of small hydroelectric generation from  
13 the City of Spokane; hydroelectric upgrades at Cabinet  
14 Gorge; approximately 7 aMW of efficiency improvements at  
15 Colstrip Units #3 and #4; and a new purchase agreement  
16 signed with Grant County PUD for a continued share of the  
17 output from the Priest Rapids and Wanapum hydroelectric  
18 projects beginning in 2005.

19 The Company is currently in a balanced-to-surplus  
20 energy position through 2017 on an average annual basis.  
21 This assumes the addition of Lancaster, which is a 245 MW  
22 gas-fired plant with an additional 30 MW of duct firing  
23 capability; this resource will be described in more detail  
24 later in my testimony. However, as I will explain later,  
25 there are monthly and quarterly deficits and surpluses

1 prior to 2017. The Company's annual energy net resource  
2 position becomes deficient in 2018 and the deficiencies  
3 increase from that time forward if additional resources are  
4 not added. The average annual energy resource deficiency  
5 beginning in 2018 is 8 aMW and increases to 515 aMW in  
6 2028.

7 The Company's capacity resource position is surplus  
8 through 2018. Capacity deficiencies begin at 67 MW in 2019  
9 and increase to 843 MW in 2028. Additional details  
10 concerning the load and resource positions are in Company  
11 witness Kalich's Exhibit No. 5, Schedule 1.

12 **Q. How does the Company plan to meet future resource**  
13 **needs beginning in 2018?**

14 A. The Company has pursued the Preferred Resource  
15 Strategy laid out in the 2007 Electric IRP. Avista's 2007  
16 Electric IRP is attached as Exhibit No. 4, Schedule 1. The  
17 IRP provides details about the need for additional  
18 resources, specific cost and operating characteristics of  
19 the resources evaluated for the Preferred Resource  
20 Strategy, and the scenarios used for resource evaluations.

21 The Company's 2007 Electric IRP was submitted to the  
22 Commission in August of 2007. The Company will continue  
23 evaluating a mix of resource options to meet future load  
24 requirements, including medium-term market purchases,  
25 generation ownership, hydroelectric upgrades, renewable

1 resources, customer load reduction (e.g., conservation),  
2 long-term contracts, and generation lease or tolling  
3 arrangements. As stated earlier, longer-term resource  
4 decisions are generally made in conjunction with the  
5 Company's IRP and RFP processes, pursuant to Commission  
6 rules, although the Company does acquire some resources  
7 outside of formal RFP processes. The Company's Preferred  
8 Resource Strategy in the 2007 IRP includes a mix of 87 MW  
9 of DSM, upgrades to its existing plants, 350 MW of gas-  
10 fired CCCT, 300 MW of wind, and 35 MW other renewable  
11 generation (such as small co-generation, biomass and  
12 geothermal).

13 The Company continues to evaluate and acquire various  
14 DSM measures. Avista has acquired approximately 96 aMW of  
15 DSM over the past eighteen years. This equates to 5.3% of  
16 the Company's owned generation. Avista continues to  
17 acquire cost-effective DSM and anticipates acquiring an  
18 additional 87 aMW of DSM over the next decade.

19 **Q. Can you please provide an overview of the Chicago**  
20 **Climate Exchange and why the Company decided to become a**  
21 **member?**

22 A. Yes, the Chicago Climate Exchange (CCX) is the  
23 only North American marketplace for integrating voluntary,  
24 verifiable and legally-binding emissions reductions with  
25 emissions trading and offsets for all six of the greenhouse

1 gases (GHG). The CCX binds members to reducing their GHG  
2 emissions by six percent through 2010 based on a baseline  
3 level of emissions established by the rules of the CCX.  
4 Members must buy credits through the CCX if they are unable  
5 to meet their GHG emissions reductions goals up to a  
6 maximum amount, or they may sell or bank credits up to a  
7 specified amount if they exceed their reduction goals.

8 Avista decided to join the CCX in order to gain  
9 experience and develop the internal infrastructure to trade  
10 GHG credits. The Company believes this skill will be  
11 necessary in anticipation of state or federal legislation  
12 regarding GHG emissions in the near future, as discussed in  
13 our 2007 Electric IRP. The CCX was also chosen because the  
14 Company anticipates that we will have credits to sell in  
15 this market. The exact number of credits through 2007 will  
16 be known after the baseline audit is completed in the first  
17 quarter of 2008. The decision of how or when to dispose of  
18 the excess credits has not been made at this time, but will  
19 be done after the audit has been completed and the official  
20 baseline and reduction goals have been established. The  
21 Company plans to pass the net proceeds of the sale of any  
22 credits on to customers through the Power Cost Adjustment  
23 (PCA) mechanism.

24

25

1 **III. HYDRO AND THERMAL PROJECT UPGRADES**

2 **Q. Please provide an update on the generation**  
3 **upgrades completed on the Cabinet Gorge Projects.**

4 A. The Company completed an upgrade of Cabinet Gorge  
5 Unit #2 in March 2004. This project consisted of removing  
6 the original 1952 propeller runner and replacing it with a  
7 current design mixed-flow runner. The upgrade resulted in  
8 a 17 MW increase in capacity, from 55 MW to 72 MW, and an  
9 increase in energy of approximately 3 aMW. The Company  
10 completed a similar upgrade project in 2001 for Cabinet  
11 Gorge Unit #3. The capacity of the unit was increased from  
12 55 MW to 72 MW which resulted in an estimated 4.5 aMW of  
13 additional energy.

14 The Company completed upgrading Cabinet Gorge Unit #4  
15 in early April 2007, and obtained an additional 10 MW of  
16 capacity and 1.1 aMW of energy from the project at a total  
17 investment of \$6.2 million (system). Company witnesses Mr.  
18 Kalich and Mr. Johnson have reflected the additional  
19 capacity and energy values in their adjustments, and  
20 Company witness Ms. Andrews included the investment costs  
21 of the upgrade.

22 **Q. Can you provide an overview of the repairs that**  
23 **have been completed and the capital improvements that are**  
24 **scheduled to be done on the Noxon Rapids Project?**

1           A.    Yes.  On June 9, 2006, the Unit #4 stator winding  
2 failed at the Noxon Rapids Project.  This unit was already  
3 scheduled to be upgraded in 2007, so the project timeline  
4 was accelerated to start in June 2006.  The total cost for  
5 the core and rewind project was approximately \$7.2 million  
6 (system), which included \$4.8 million for the rewind and  
7 \$2.4 million for the core.  Ms. Andrews has reflected  
8 Idaho's share of this investment in her adjustments.  The  
9 second step to complete the Unit #4 upgrade involves  
10 replacement of the turbine runner, which will be done  
11 between 2011 and 2012.

12           Currently, work is being done on Unit #5, the largest  
13 and most efficient unit at the project, which was installed  
14 in 1977.  This reliability work began in September 2007 and  
15 is expected to be completed by April 2008.  The work is not  
16 expected to increase the units 92.0% efficiency rating or  
17 the 125 MW unit rating, but is expected to solve several  
18 reliability concerns.  The reliability concerns for Unit #5  
19 include stator frame distortion, varying air gap, numerous  
20 forced outages, and the need to have a one-hour pre-warming  
21 of thrust bearings prior to the unit being started.  The  
22 costs associated with this work is approximately \$1.6  
23 million (system) and has been included in this case as  
24 further described in Company witness Mr. DeFelice's

