

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-07_____

DIRECT TESTIMONY OF

RICHARD L. STORRO

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

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

A. My name is Richard L. Storro. I am employed as the Director of Power Supply by Avista Corporation located at 1411 East Mission Avenue, Spokane, Washington.

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

A. I received a Bachelor of Science degree in physics from the College of Idaho and a Bachelor of Science degree in electrical engineering from the University of Idaho, both in 1973. I started working for Avista in 1973 as a distribution engineer. Since that time I have worked in various engineering positions. I have held management positions in line and gas operations, system operations, hydro production and construction, and transmission. I joined the Energy Resources Department as a Power Marketer in 1997 and became Director of Power Supply in 2001. My primary responsibilities involve management and oversight of the short- and long-term planning and acquisition of power resources for the Company.

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

A. My testimony will provide an overview of Avista's resource planning and power operations, and comments concerning resource planning in light of new and pending legislation. I will provide an update on the Company's hydro and thermal plant upgrades. I will provide a status report on the Company's FERC license commitments at the Clark Fork River hydroelectric projects as well as the current relicensing efforts for the Spokane River hydroelectric projects. Finally, I will address the Company's hedging strategy and its Risk Management Policy.

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10 **Q. Are you sponsoring any exhibits?**

11 A. Yes. I am sponsoring Exhibit Nos.__(RLS-2) (Avista's 2005 Electric Integrated
12 Resource Plan), __(RLS-3) (Map – Spokane River Hydroelectric Project), which were prepared
13 under my direction, and __(RLS-4) (Avista Utilities' Energy Resources Risk Policy –
14 Confidential).

15

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

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

19 A. Yes. Avista's resource portfolio consists of a diverse asset mix that includes
20 hydroelectric generation projects, base-load coal and natural gas-fired thermal generation
21 facilities, wood waste-fired renewable generation, natural gas-fired peaking generation projects,
22 long-term contracts including wind generation and Mid-Columbia hydroelectric generation, and
23 market power purchases and exchanges. Avista-owned generation facilities have a total
24 capability of 1,823 MW, of which 54% is hydroelectric and 46% is thermal.

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1 Table 1 summarizes the present capability of Avista's owned generation resources.

2 **Table 1 – Avista Owned Generation**

Company-Owned Projects	MW
Noxon Rapids	527
Cabinet Gorge	261
Post Falls	18
Upper Falls	10
Monroe Street	15
Nine Mile	25
Long Lake	88
Little Falls	36
Total Hydroelectric Generation	980
Colstrip Units 3 and 4	230
Coyote Springs 2	287
Kettle Falls	51
Total Base-Load Thermal Generation	568
Northeast CT	67
Kettle Falls CT	7
Boulder Park	25
Rathdrum CT	176
Total Natural Gas Peaking Generation	275
Total Generation	1,823

3
4 In addition to the above mix of Company-owned generation resources, the Company has
5 long-term contractual rights for a total of 138 MW of capability from the Mid-Columbia
6 generation projects that are owned and operated by the Public Utility Districts of Grant, Chelan,
7 and Douglas counties. The Company also has a ten-year contract in place for the purchase of 35
8 MW of wind generation capability from the Stateline Wind Project. The Company also receives
9 100 MW of energy from various parties under contracts through 2010.

10 **Q. Would you please provide a brief overview of Avista's resource planning and**
11 **power supply operations?**

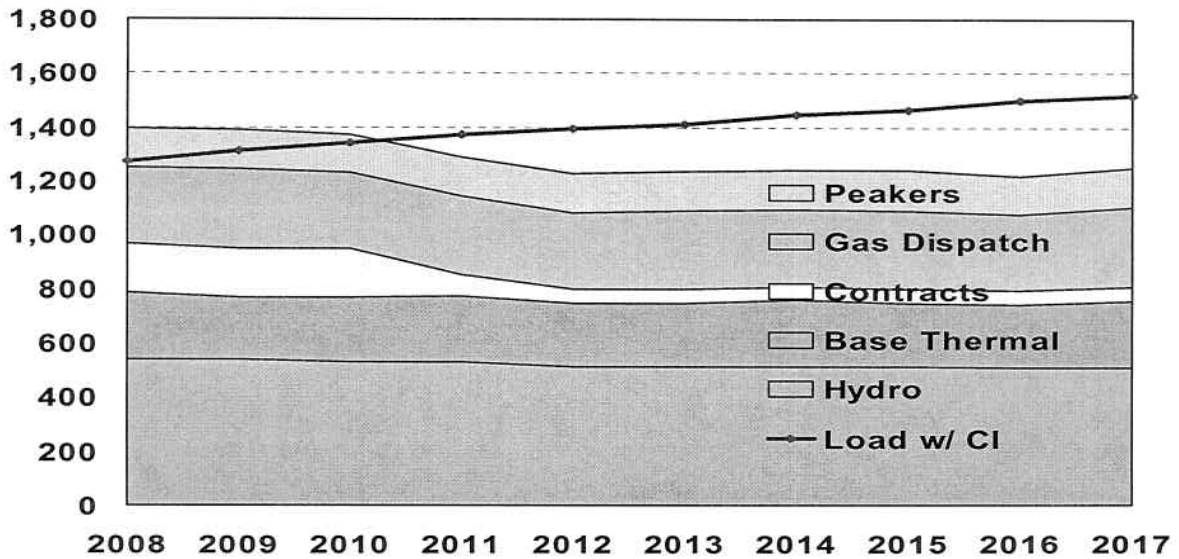
1 A. Yes. As explained above, the Company uses a combination of owned and
2 contracted-for resources to serve its retail and contractual requirements. Dispatch decisions
3 related to these resources are made within the Power Supply sections of Avista Utilities' Energy
4 Resources Department. The Department regularly conducts studies to determine capacity and
5 energy resource needs. To meet requirements in the shorter time frames, the Department engages
6 in weekly strategy meetings to incorporate new and updated information that affects our load and
7 resource position. The Company enters into short and medium-term wholesale sales and
8 purchase transactions to balance resources with load requirements. Longer-term resource
9 decisions related to building new resources, upgrading existing resources, demand-side
10 management (DSM), and long-term contract purchases are generally made in conjunction with
11 the Company's Integrated Resource Plan (IRP) and Request for Proposals (RFP) processes. The
12 Company also acquires some resources without conducting a formal RFP process.

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

14 A. The Company is currently in a balanced-to-surplus energy position through 2010
15 on an average annual basis. However, as I will explain later, there are monthly and quarterly
16 deficits and surpluses through the years prior to 2010. In general terms, the Company's annual
17 energy net resource position becomes deficient in 2011 and the deficiencies increase substantially
18 in 2012 and beyond. The average annual energy resource deficiency beginning in 2011 is 83
19 aMW and increases to 272 aMW in 2017. The Company's capacity resource position is surplus
20 through 2010. Capacity deficiencies begin in 2011 at 146 MW and increase to 300 MW in 2017.
21 Chart Nos. 1 and 2 visually represent the Company's energy and capacity resources positions

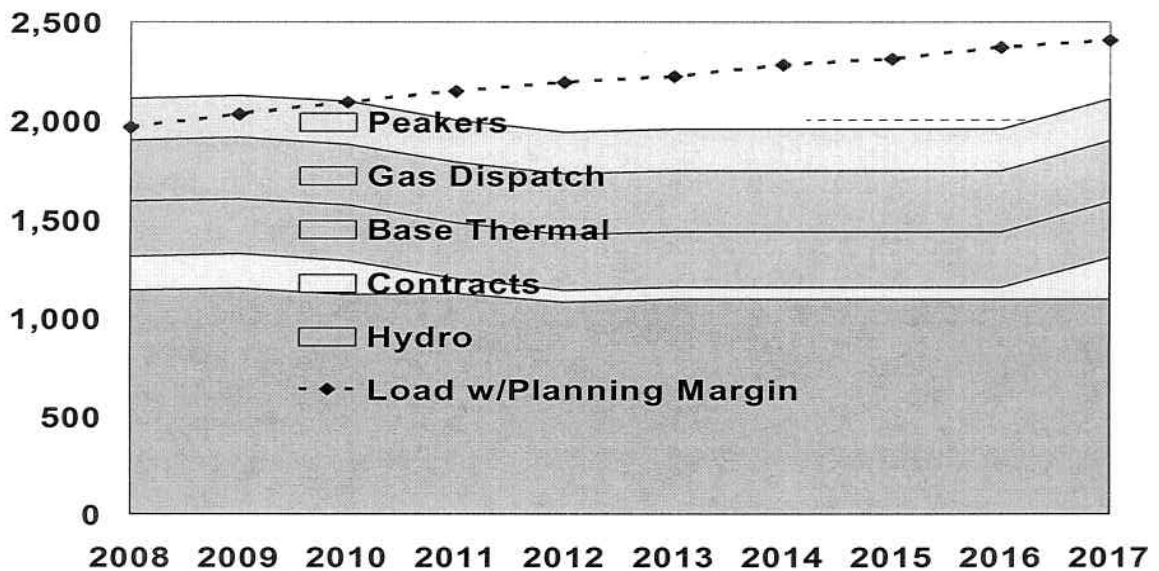
1 from 2008 through 2017. A 60-MW reduction is applied both to load and contracts on both
 2 charts to reflect the adjustment for Potlatch.

3 **Chart No. 1 – Avista 2008-2017 Load and Resource Energy Position (aMW)**



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5 **Chart No. 2 – Avista 2008-2017 Load and Resource Capacity Position (MW)**



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7 Additional details concerning the load and resource positions are in Company witness Mr.

8 Kalich's Exhibit No.__(CGK-2).

1 **Q. How does the Company plan to meet future resource needs beginning in**
2 **2011?**

3 A. The Company has pursued the preferred resource strategy laid out in the 2005
4 Electric IRP. A compact disk (CD) copy of Avista's 2005 Electric IRP is attached as Exhibit
5 No.__(RRP-2). Hard copies will be made available upon request. The IRP provides details
6 about the need for additional resources, specific cost and operating characteristics of the
7 resources that were evaluated, and the range of scenarios used for resource evaluations.
8 Significant changes in the preferred resource strategy, however, will be evident in the 2007 IRP
9 due to recent legislation promoting renewable and low carbon emission resources.

10 The development of the Company's 2007 IRP is currently in progress and is scheduled
11 for release in August 2007. The Company will continue evaluating a mix of resource options to
12 meet future load requirements including medium-term market purchases, generation ownership,
13 hydroelectric upgrades, renewable resources, customer load reduction (i.e., conservation), long-
14 term contracts, and generation lease or tolling¹ arrangements. As stated earlier, longer-term
15 resource decisions are generally made in conjunction with the Company's IRP and RFP
16 processes, pursuant to Commission rules, but the Company does acquire some resources outside
17 of formal RFP processes. The Company's preferred resource strategy in the 2007 IRP includes a
18 mix of conservation, upgrades to its existing plants, thermal, wind, and other renewable
19 generation.

¹ "Tolling" is an energy conversion service where customer supplied natural gas is converted to electric energy which is delivered to the customer based on a defined conversion ratio. The conversion ratio can be tied to the heat rate and variable operating costs of a generating plant. The fixed cost of the plant can be covered in fixed fees charged by the tolling service provider. Tolling service is generally contingent on the operation of a specific plant.

1 The Company has added a variety of resources to its portfolio in recent years, including:
2 the second half of Coyote Springs 2; a ten-year agreement for 35 MW of wind generation
3 capability (estimated 7.6 aMW); medium-term purchases of 100 aMW through 2010; the
4 purchase of approximately 7 aMW of small hydroelectric generation from the City of Spokane;
5 hydroelectric upgrades at Cabinet Gorge; approximately 3.5 aMW of efficiency improvements at
6 Colstrip Unit #4; and a new purchase agreement signed with Grant County PUD for a continued
7 share of the output from the Priest Rapids and Wanapum hydroelectric projects beginning in
8 2005.

9 The Company continues to evaluate and acquire conservation. Avista acquired
10 approximately 90 aMW of DSM over the past eighteen years. This represents 4.9% of the
11 Company's owned generation. Avista continues to acquire cost-effective DSM and anticipates
12 acquiring an additional 54 aMW of DSM over the next decade. We are also actively engaged in
13 planning to acquire additional renewable resources to satisfy I-937 – the Washington Clean
14 Energy Initiative.

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III. RESOURCE PLANNING

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**Q. Please provide an overview of the effects of recently passed and proposed
legislation on resource planning issues.**

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A. There are two main pieces of legislation in Washington State that will affect
resource planning through the Integrated Resource Plan: the Washington Clean Energy Initiative
and Washington Senate Bill 6001 (SB 6001). The Washington Clean Energy Initiative (I-937)
passed in the November 2006 election. In regards to electric generation, I-937 specified that 3%

1 of Avista's retail load in Washington will be served from new renewable resources by 2012, 9%
2 by 2015, and 15% by 2020. There are \$50/MWh penalties for not reaching these goals, as well
3 as a renewables spending cap of 4% of the incremental costs of the Washington-share of the
4 annual retail revenue requirement (approximately \$11.8 million in 2012, based on 2007 revenue).
5 Our 2007 IRP is being developed to meet the goals and objectives of I-937.

6 SB 6001 would establish programs and procedures to reduce state greenhouse gas
7 emissions to 1990 levels by 2020, 25% below 1990 levels by 2035, and 50% below 1990 levels
8 by 2050. SB 6001 also intends to increase clean energy sector employment to 25,000 by 2020
9 and reduce fuel imports into the state by 2020. The main effect of this bill on Avista will be in
10 regards to long-term energy resources through an emissions performance standard. This bill
11 applies a greenhouse gas emissions standard on new baseload generation of 1,100 pounds of
12 greenhouse gases per megawatt-hour if emissions are not permanently sequestered. This
13 provision essentially limits new baseload plants to a natural gas-fired combined cycle combustion
14 turbine.

15 These two bills will require utilities to shift their focus away from least cost planning in
16 the IRP selection process and focus more on meeting renewable and emissions standard
17 requirements. The resource mix in the 2007 IRP will consider a mix of natural gas turbines,
18 wind power, DSM, project upgrades, and other types of renewable power including biomass,
19 geothermal, and methane digesters.

20 **Q. Has the Company completed any analysis concerning the effects of the**
21 **initiative and proposed legislation?**

1 A. Yes, the Company has studied the Washington Clean Energy Initiative (I-937) and
2 participated in the proceeding concerning the implementation of this initiative. The Company
3 has concerns about the availability of a suitable number of cost-effective renewable projects to
4 meet the goals of this initiative because of the legislatively increased demand for these types of
5 projects throughout the Western states. We are now in competition for renewable projects with
6 utilities from other states who are also trying to satisfy their own renewable portfolio standards.
7 This has resulted in significant increases in prices. For example, our 2005 IRP estimated the
8 capital costs of wind energy at \$1,131/kW and the 2007 IRP estimates are for \$1,600 to
9 \$2,000/kW for wind energy.

10 For illustrative purposes, at the \$2,000/kW level for capital costs and a 33% capacity
11 factor, wind energy costs approximately 10 cents/kWh. This cost does not include transmission,
12 integration, and operating costs, or the benefit of the current federal production tax credit. Our
13 analysis has shown a need for 24 aMW of renewables by 2012 and 138 aMW of renewables by
14 2020. The 4% cost cap to obtain these renewable resources works out to \$14.8 million for the
15 20-year levelized cost. Table 2 shows the impact of I-937 on Avista's electric generation
16 requirements.

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Table 2 – Washington RPS Requirement (Based on Washington Load)

Year	RPS Requirement as a % of load	RPS Requirement (aMW)	Current and Planned Renewables (aMW)	Additional Renewables Needed (aMW)
Present	N/A	N/A	10	N/A
2012	3%	24	15	9
2016	9%	77	15	62
2020	15%	138	15	123

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IV. HYDRO AND THERMAL PROJECT UPGRADES

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Q. Please provide an update on generation upgrades to the Clark Fork River Projects.

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A. The Company completed an upgrade of Cabinet Gorge Unit #2 in March 2004.

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This project consisted of removing the original 1952 propeller runner and replacing it with a

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modern design mixed-flow runner. The upgrade resulted in a 17 MW increase in capacity, from

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55 MW to 72 MW, and an increase in energy of approximately 3 aMW. The Company

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completed a similar upgrade project in 2001 for Cabinet Gorge Unit #3. The capacity of the unit

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was increased from 55 MW to 72 MW and an estimated 4.5 aMW of additional energy.

12

The Company recently completed upgrading Cabinet Gorge Unit #4, and expects to

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obtain an additional 10 MW of capacity and 1.1 aMW of energy from the project with Unit #4

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returned to service in early April 2007, at a total investment of \$6.2 million (system). Company

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witnesses Mr. Kalich and Mr. Johnson have reflected the additional capacity and energy values in

1 their adjustments, and company witness Ms. Andrews has included the investment costs of the
2 upgrade.

3 **Q. Can you provide an overview of the repairs and capital improvements that**
4 **are being done on the Noxon Rapids Project?**

5 A. Yes. On June 9, 2006, the Unit #4 stator winding failed at the Noxon Rapids
6 Project. This unit was already scheduled to be upgraded in 2007, so work at this project was
7 accelerated to start in June 2006. The total cost for the core and rewind project is approximately
8 \$7.2 million (system), which includes \$4.8 million for the rewind and \$2.4 million for the core.
9 Ms. Andrews has reflected this investment in her adjustments.

10 This rewind would have been a part of a project upgrade in 2007. The unit is expected to
11 return to service by September 2007. The other four units at Noxon Rapids are ready to generate
12 energy from the available streamflow so there is minimal, if any, lost energy production beyond
13 the spring runoff period. The second step to complete the upgrade to Unit #4 involves the
14 replacement of the turbine runner, which will be done at a later time than originally planned
15 because of the winding failure.

16 We also plan to upgrade units 1 through 3 at Noxon Rapids. Including the work on Unit
17 4, the upgrades are expected to add an additional 38 MW of capacity and 6 aMW of energy to the
18 Noxon Rapids project. One upgrade is planned for each year, starting in March 2009 with
19 completion of all upgrades currently planned by 2012.

20 **Q. Please explain the capital improvements that are being done on Colstrip Units**
21 **3 and 4?**

1 A. Capital improvements on Colstrip Units 3 and 4 began in 2006 to improve
2 operating efficiency, reliability, and to increase generation. Colstrip Unit #4 was taken down on
3 May 8, 2006 to install a new high-pressure steam turbine rotor, which resulted in approximately
4 28 MW (4.2 MW Company share) in additional capacity using the same amount of fuel. The
5 original analog plant controls were also replaced with digital controls to optimize plant operation.
6 The unit was brought back on line on June 25, 2006. Avista's share of the total investment cost
7 for the Unit #4 upgrade was approximately \$3.0 million (system).

8 On Colstrip Unit #3, the analog to digital control conversion was completed last year and
9 additional capital improvements are scheduled for May and June of 2007 at a total investment for
10 Avista of \$3.8 million (system). These improvements include the installation of a new high-
11 pressure steam turbine rotor to improve output and efficiency and the installation of NO_x controls
12 on the boiler. These changes are expected to add approximately 28 MW (4.2 MW Company
13 share) in additional capacity. Witnesses Kalich and Johnson have included the additional
14 benefits and operating costs from the upgrades in their adjustments, and witness Andrews has
15 reflected the investment costs in her testimony.

16 **Q. Could you summarize the costs and timing of the hydro and thermal**
17 **upgrades included in this case?**

18 A. Yes. Table No. 2 lists the in-service dates, system investment costs, and the
19 Washington allocation for each project. Ms. Andrews explains the Washington allocation of rate
20 base and revenue requirements associated with these upgrades.

Table No. 2 – Generation Project Costs

Generation Projects ⁽¹⁾	Cost: System / WA (000s)	In-Service Date
Cabinet Gorge Unit 4	\$6,200 / \$4,081	Mar-07
Noxon Rapids Unit 4	\$7,189 / \$4,733	Sep-07
Colstrip Unit 4	\$2,949 / \$1,941	Jun-06
Colstrip Unit 3	\$3,760 / \$2,475	Jun-07
Total	\$20,098 / \$13,230	
⁽¹⁾ The additional generation from the Cabinet Gorge Unit 4 and Colstrip Units 3 & 4 project upgrades has been included in the AURORA model as discussed by Company witness Mr. Kalich.		

V. HYDRO RELICENSING

Q. Would you please provide an update on work being done under the existing FERC operating license for the Company's Clark Fork River generation projects?

A. Yes. Avista received a new 45-year FERC operating license for its Cabinet Gorge and Noxon Rapids hydroelectric generating facilities on March 1, 2001. The Company has made significant progress working in collaboration with 27 signatories to the Clark Fork Settlement Agreement toward meeting the goals, terms, and conditions of the Protection, Mitigation and Enhancement (PM&E) measures under the license. The implementation program has resulted in the protection of approximately 2,500 acres of bull trout, wetlands, uplands, and riparian habitat. The fish passage program, using electrofishing and trapping with over 150 adults radio tagged and their movements studied, has reestablished bull trout connectivity between Lake Pend Oreille and the Clark Fork River tributaries above Cabinet Gorge Dam. Avista has worked with the U.S. Fish and Wildlife Service to develop two experimental fish passage facilities over the last four years. The testing of these facilities has not produced a design that will attract adult bull trout. However, studies will continue to seek solutions for developing a volitional fish passage facility. Juvenile bull trout on their downstream migration are collected in tributary streams, tagged and

1 transported to the Clark Fork River downstream of Cabinet Gorge Dam to test the survival of
2 adults. The costs associated with the PM&E measures were reviewed in a prior case and are
3 included in retail rates.

4 When the new Clark Fork license was received, total dissolved gas levels occurring
5 during spill periods at Cabinet Gorge Dam was an unresolved issue. The license allowed several
6 years to study the actual biological impacts of dissolved gas and subsequent development of a
7 mitigation plan including cost estimates. The studies documented no biological impact from
8 dissolved gas below the project; however, the stakeholders ultimately concluded that dissolved
9 gas levels should be mitigated, in accordance with federal and state law. A plan to reduce
10 dissolved gas levels was developed with all stakeholders, including the Idaho Department of
11 Environmental Quality. The plan called for the modification of two existing diversion tunnels, to
12 divert streamflows exceeding turbine capacity away from the spillway. The plan called for
13 modification of the first tunnel by 2010 at an estimated cost of \$38 million. The second tunnel
14 would only be constructed after a performance analysis and an evaluation of the environmental
15 benefits of the first tunnel. The Company, with the support of engineering contractors, has spent
16 the past two years developing feasibility and cost studies to retrofit the first tunnel. The
17 Preliminary Design Development Report was recently completed and the project did not meet the
18 established performance criteria and the estimated cost of the first tunnel increased to \$58
19 million. Discussions of this issue with stakeholders and key agencies will continue in 2007. In
20 the meantime, the Company is identifying and evaluating alternatives to the tunnels project, as
21 well as conducting additional modeling and analysis on the existing tunnel design. A final report

1 is scheduled to be completed in November 2007. The Company has not included the costs of this
2 project in this rate request.

3 **Q. Would you please give an update on the status of your efforts to relicense the**
4 **Spokane River Hydroelectric Projects?**

5 A. Yes. The Company filed applications with FERC in July 2005 to relicense five of
6 its six hydroelectric generation projects located on the Spokane River. The Spokane River
7 Project, which is currently under a single FERC license, includes Long Lake, Nine Mile, Upper
8 Falls, Monroe Street, and Post Falls. Little Falls, the Company's sixth project on the Spokane
9 River, is not under FERC jurisdiction, but operates under separate Congressional authority. A
10 separate license application was made for the Post Falls Project due to the unique circumstances
11 that surround the future operation of the facility. A separate licensing track for the four
12 developments downstream of Post Falls is expected to provide a more efficient and timely
13 process for moving ahead with a new FERC license for those developments. Exhibit
14 No.__(RRP-3) includes a map of the Spokane River Project showing the location of the
15 Company's six hydroelectric developments.

16 The five FERC jurisdictional developments have a total generating capacity of
17 approximately 156 MW, and average annual energy production of approximately 105 aMW. Our
18 current license for the Spokane River Project expires in August 2007. We developed these
19 applications using FERC's alternative licensing procedures.

20 Since the filing of the applications, we have been meeting FERC's procedural
21 requirements as they process the applications. In July 2006, government agencies and Native
22 American tribes submitted proposed terms and conditions for the relicensing applications. These

1 submittals included mandatory conditions submitted by the Department of Interior and Bureau of
2 Indian Affairs for the Post Falls Project. In August 2006, Avista requested a trial-type hearing in
3 front of an Administrative Law Judge (ALJ) at the U.S. Department of the Interior concerning the
4 factual bases for the proposed conditions. The ALJ held a hearing in December 2006 and issued
5 a finding of facts on January 8, 2007. The ALJ's findings should be the basis for the Department
6 of the Interior's final mandatory conditions, which are expected to be issued in late 2007.

7 In addition, FERC issued a Draft Environmental Impact Statement (DEIS) in early 2007,
8 held public hearings in February 2007, and received formal comments through March 6, 2007.
9 The DEIS analyzes Avista's applications, as well as proposed recommended and mandatory
10 conditions. Many parties filed comments on the DEIS. FERC is expected to issue a final EIS in
11 late 2007.

12 To meet additional relicensing requirements, Avista filed applications for Clean Water
13 Act Section 401 Certification in July 2006 with the Washington Department of Ecology and the
14 Idaho Department of Environmental Quality. According to statutory timeframes, these
15 certifications are expected by July 2007. Avista also prepared a draft Biological Assessment as
16 the designated non-federal representative for consultation under the Endangered Species Act
17 (ESA). In early 2007, FERC issued a Biological Opinion and requested concurrence from the
18 U.S. Fish and Wildlife Service ("the Service") that the Post Falls and Spokane River Projects
19 would be "not likely to adversely affect" any A-listed species. The Service concurred with the
20 determination with respect to bald eagles, and stated that more information would be needed
21 before a concurrence decision could be reached regarding bull trout. The timing for this
22 resolution is currently unknown.

1 At this time, Avista believes that it is unlikely that FERC will issue license order
2 decisions for the Post Falls and Spokane River Projects in 2007, and it will continue to operate
3 under an annual license until this matter is settled. Avista continues to resolve issues related to
4 these hydroelectric developments through agreements where possible.

5 **Q. Are any relicensing costs included in this case?**

6 A. No. A new license for the Spokane River Projects is not expected to be issued in
7 2007. We plan to request cost recovery in a future proceeding through a general rate case,
8 PCORC, or deferred accounting request; in a manner that would provide timely recovery of the
9 costs, coincident with the issuance of the new license.

10 **Q. Are there any other issues in regards to the Spokane River Projects that you**
11 **would like to discuss?**

12 A. Yes. In 1998, the United States District Court for the District of Idaho determined
13 that the Coeur d'Alene Tribe (CDA Tribe) owns portions of the bed and banks of Lake Coeur
14 d'Alene that are within the current boundaries of the Coeur d'Alene Reservation, which are
15 approximately the Southern third of Lake Coeur d'Alene. This decision was affirmed by the
16 United States Supreme Court in 2001. This ruling directly impacts the Company because Avista
17 owns and operates the Post Falls Hydroelectric Generating Station (Post Falls). This plant was
18 constructed in 1906 approximately seven river miles downstream from the outlet of Lake Coeur
19 d'Alene. This facility controls the lake water level during portions of the year. The ruling
20 resulted in the Company being liable for compensation to the CDA Tribe for water storage on
21 reservation lands under Section 10(e) of the Federal Power Act. The Company and the CDA
22 Tribe are engaged in ongoing discussions with respect to past and future compensation. The

1 Company has not included costs related to this issue in this filing. The Company plans to seek
2 recovery of costs associated with the resolution of this issue in a future general rate case,
3 PCORC, or deferred accounting request.
4

5 VI. AVISTA'S HEDGING AND RISK MANAGEMENT PROGRAM

6 **Q. Can you provide an overview of Avista's hedging strategy and risk**
7 **management program for energy resources?**

8 A. Yes, Avista Utilities uses a variety of systemic techniques to manage the risks
9 associated with serving load and managing Company resources. The Company's risk
10 management approach uses price diversification through a layering strategy for forward
11 purchases and sales, and by using stop loss price controls to protect against market price run-ups
12 and run-downs by utilizing upper and lower price control limits. The Energy Resources Risk
13 Policy provides general guidance to manage the Company's energy risk exposure, as it relates to
14 electric power and natural gas resources over the long (more than 18 months), short (monthly and
15 quarterly periods out to 18 months), and immediate terms (present month). The purpose of the
16 Risk Policy is not to develop a specific procurement plan for buying or selling power or natural
17 gas for generation at any particular time. Several factors, including the variability associated
18 with loads, hydroelectric generation, and electric power and natural gas prices, are considered in
19 the decision-making process regarding procurement of electric power and natural gas for
20 generation. The Risk Policy addresses the types of risks that are covered, power and natural gas
21 supply positions, authorized transactions, resource optimization, reports, credit and contracts,
22 information systems, confirmation and settlement, and employee conduct. There are also five

1 exhibits covering authorized products, the electric hedging plan, the natural gas hedging plan,
2 roles and responsibilities, and transaction authority levels. Exhibit No.__(RLS-4) is a copy of the
3 Avista Utilities Energy Resources Risk Policy.

4 **Q. What types of risks are addressed in the Risk Policy?**

5 A. The Risk Policy defines several different types of risk and how they are to be
6 addressed. Exhibit No.__(RLS-4) provides specific details concerning each of these risks. The
7 Risk Policy does not supersede the responsibilities of other areas of the Company that are
8 responsible for other risk management issues, such as Treasury, and corporate Information
9 Systems. The most relevant types of defined risks addressed in the Policy are the mitigation of
10 market risks and the description and assignment of roles and responsibilities in internal
11 operations risks.

12 **Q. What is the power supply position and how does it fit into the Risk Policy?**

13 A. The power supply position is the difference between electric resources and
14 requirements. Surplus positions occur when resources exceed requirements and deficits occur
15 when requirements exceed resources. Power supply position considers all of the variables that
16 affect power supply. The dynamic nature of the power supply position is actively managed by
17 establishing control processes for load and obligation estimation, resource estimation, and
18 management of the expected net surplus or deficit position. All of these areas are under my
19 responsibility as the Director of Power Supply. Similar position issues are also addressed
20 regarding natural gas supplies for turbine generation. Any changes to practices are
21 communicated to the Risk Management Committee.

1 Electric loads and obligations in the Risk Policy are estimated based upon an analysis of
2 historic loads, adjusting for weather variability, expected additions or decreases in large customer
3 loads, all known wholesale contract obligations, and adjustments as necessary based on analysis
4 of prior estimating accuracy and other factors. Electric resources are estimated based on
5 expected output after consideration for variability in conditions such as streamflow, forced
6 outages, maintenance, and environmental concerns.

7 Electric surplus and deficit positions are hedged using the electric hedging plan as a guide
8 which can be deviated from based on management judgment of each surplus or deficit situation.
9 All changes to the Short Term electric position are reported every business day in an electric
10 position report.

11 **Q. Please describe the electric hedging plan.**

12 A. The electric hedging plan, detailed in Exhibit 2 of the Risk Policy (Exhibit
13 No.__(RLS-4)), relies heavily upon the Hedge Scheduler. The Hedge Scheduler is an analytical
14 tool used to guide power supply decisions. This tool provides a process for systematically
15 reducing open power positions with forward purchases and sales of power or fuel for generation.
16 Price control limits and time periods are employed to trigger purchases or sales to cure open
17 positions. The curing transaction occurs whenever a price control limit is exceeded or the cure
18 period expiration date is crossed. The Hedge Scheduler is only a guide that is not used in a rigid
19 manner if management judgment or market conditions warrant different actions than those
20 indicated by the tool. Examples of situations that may warrant deviations are short periods of
21 abnormally high market prices due to storms or other shorter term anomalies.

22

1 **Q. How does the Hedge Scheduler work?**

2 A. The Hedge Scheduler covers a period of time from the next whole calendar month
3 out to 14 to 18 months. The 14 to 18 month electric load and resource forecast is used by the
4 Hedge Scheduler to model a series of transactions to “systematically reduce the net open
5 position” (the gap between expected load obligations and projected power resources) which
6 limits the Company’s projected financial exposure to less than 25 aMW in any given month. The
7 transactions are generally in 25 aMW increments which include a mixture of electric commodity
8 purchases or fuel transactions (natural gas purchases to fuel thermal generation).

9 The actual operation of the Hedge Scheduler utilizes separate schedules for on- and off-peak
10 positions. The position is cured in 25 aMW pieces where price limits are established based on
11 the price volatility for the delivery period. Upper and lower confidence limits are initially
12 established as the standard deviation of the prior 365 days of forward prices for the delivery
13 period being considered. The values are centered around the set price. The periods are
14 established by calculating the time remaining divided by the number of 25 aMW pieces that need
15 to be cured.

16 **Q. What is hydro bias and how does it affect the Electric Hedging Plan?**

17 A. Hydro bias is a physical power quantity held in the load and resource position to
18 protect against below normal hydro conditions. Abnormal hydro conditions can result in
19 significant price risk, particularly in the upward direction. In low hydro conditions, purchasing
20 power in the spot market can result in high upside price risk up to the \$400/MWh price cap.
21 During high hydro conditions, there is downside price risk associated with selling excess power
22 in an oversupplied market, but the price cannot go below zero. The Hydro Bias is used in the

1 Hedge Scheduler to provide a conservative estimate for hydro generation which mitigates the
2 potentially adverse financial impacts of poor hydro conditions. The allowance for lower than
3 normal hydro conditions is recognized as an estimated power obligation within the current (18
4 month forward period) hydro operating year. The size of the Hydro Bias is developed by
5 analyzing generation variability under historic conditions from the 70-year hydro record (1928-
6 1998). Above normal hydro conditions are limited to normal levels, while below normal
7 conditions are left in tact. These levels are multiplied by a one standard deviation confidence
8 factor to determine the Hydro Bias value. The Hydro Bias decreases as the delivery period
9 approaches and better hydro forecasts are available. The Hydro Bias goes to zero before the
10 delivery month is reached.

11 **Q. Could you please describe when and what triggers purchases or sales of natural**
12 **gas for thermal generation used to serve load?**

13 A. Yes, the Hedge Scheduler triggers described above provide a guideline for when to
14 purchase or sell power or fuel. When a transaction is indicated by the Hedge Scheduler, either
15 purchase or sale, the economics of thermal plants are evaluated for the period to determine if the
16 power needed should be met with gas generation. (A portion of the daily position report analyzes
17 the “Economic Fuel Requirements” of each gas-fired thermal plant.) If a need for power is
18 indicated by the Hedge Scheduler and a thermal plant is economic and available for the time
19 period, natural gas is purchased to resolve the trigger. The thermal resources are evaluated daily
20 to determine if any previously-purchased natural gas has become uneconomic versus the forward
21 power market. When uneconomic natural gas has been verified by market quotes, the natural gas
22 is sold and power is purchased to replace the reduction in generation. Although the transaction

1 may result in a loss on the gas sale, the lower cost of the power being purchased offsets the loss
2 and the net impact is always a benefit to customers.

3 **Q. How do natural gas purchases for thermal generation impact the power**
4 **supply position?**

5 A. The volume of power generation resulting from natural gas purchases is included
6 as a resource in the power supply position calculation. To the extent that fixed price (i.e. hedged)
7 natural gas has not been purchased for a thermal plant, the generation for that plant is not counted
8 as a resource in the power supply position.

9 **Q. What is the impact of the hedge scheduler on the cost of gas for generation?**

10 A. The hedge scheduler causes gas purchases for generation to be purchased in layers
11 over time. As economic purchases and sales are made, the gas price reflects the market at the
12 time the transaction is made. This results in a cost of gas that is an average of all the transactions
13 rather than a price at a point in time.

14 **Q. What are the benefits of the “hedge scheduler” approach?**

15 A. The hedge scheduler causes long or short power positions to be resolved over
16 time. The benefits of this approach are: it layers in purchases and sales of power and fuel over a
17 rolling period of time so that all purchases or sales are not made when prices may be unusually
18 high or low; it allows purchases and sales to occur as more and better information comes
19 available on generation resources (e.g. snow pack, rainfall, and hydro conditions) and loads; and
20 it resolves open positions by the time we get to the relevant period.

21

22

1 **Q. How are transactions authorized in the Risk Policy?**

2 A. The Risk Policy establishes parameters for different types of transactions. These
3 parameters specify individuals and positions along with the types and lengths of transactions they
4 are authorized to carry out. The details of transaction authorizations are provided in Exhibit 1 of
5 the Risk Policy. (Exhibit No.__(RLS-4))

6 **Q. Are other topics covered in the Risk Policy?**

7 A. Yes. Besides subjects that are specifically related to gas resources that have not
8 been fueled, there are a variety of areas that are covered under the Risk Policy. These areas
9 include reports, credit terms, counterparty contracts, information systems, confirmation and
10 settlement, employee conduct, and risk policy updates. Additional details about these areas are
11 contained in Exhibit No.__(RLS-4).

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

13 A. Yes it does.