

DAVID J. MEYER
VICE PRESIDENT AND CHIEF COUNSEL OF
REGULATORY & GOVERNMENTAL AFFAIRS
AVISTA CORPORATION
P.O. BOX 3727
1411 EAST MISSION AVENUE
SPOKANE, WASHINGTON 99220-3727
TELEPHONE: (509) 495-4316
FACSIMILE: (509) 495-8851

RECEIVED
2010 MAR 23 AM 11:04
IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION)
OF AVISTA CORPORATION FOR THE)
AUTHORITY TO INCREASE ITS RATES)
AND CHARGES FOR ELECTRIC AND)
NATURAL GAS SERVICE TO ELECTRIC)
AND NATURAL GAS CUSTOMERS IN THE)
STATE OF IDAHO)
_____)

CASE NO. AVU-E-10-01
CASE NO. AVU-G-10-01

DIRECT TESTIMONY
OF
RICHARD L. STORRO

FOR AVISTA CORPORATION

(ELECTRIC & NATURAL GAS)

1 I. INTRODUCTION

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

4 A. My name is Richard L. Storro. I am employed as
5 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 physics from the College of Idaho and a Bachelor of
12 Science degree in electrical engineering from the
13 University of Idaho, both in 1973. I began working for
14 Avista in 1973 as a distribution engineer and have held
15 several other engineering positions with the Company. I
16 have held management positions in line and gas operations,
17 system operations, hydro production and construction, and
18 transmission. I joined the Energy Resources Department as
19 a Power Marketer in 1997, became Director of Power Supply
20 in 2001, became President of Avista Ventures in 2007, and
21 became Vice President of Energy Resources in January 2009.

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

3 A. My testimony provides an overview of Avista's
4 resource planning and power supply operations. This
5 includes summaries of the Company's generation resources,
6 the current and future load and resource position, future
7 resource plans, and an update on the Company's plans
8 regarding the acquisition of new renewable resources. I
9 will address hydroelectric and thermal project upgrades,
10 followed by an update on recent developments regarding
11 hydro licensing.

12 A table of contents for my testimony is as follows:

	<u>Description</u>	<u>Page</u>
13		
14	I. Introduction	1
15	II. Avista's Resource Planning and Power Operations	3
16	III. Generation Capital Projects	13
17	IV. Hydro Relicensing	19
18		
19		
20		

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

22 A. Yes. I am sponsoring Exhibit No. 4, Schedule
23 1C, which includes a Confidential copy of Avista's Energy
24 Resources Risk Policy and Schedule 2 includes Avista's
25 2009 Electric Integrated Resource Plan.

26

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

2 Q. Would you please provide a brief overview of
3 Avista's generating resources?

4 A. Yes. Avista's resource portfolio consists of
5 hydroelectric generation projects, base-load coal and
6 natural gas-fired thermal generation facilities, wood
7 waste-fired renewable generation, natural gas-fired
8 peaking generation projects, long-term contracts including
9 wind and Mid-Columbia hydroelectric generation, and market
10 power purchases and exchanges. Avista-owned generation
11 facilities have a total capability of 1,777 MW, which
12 includes 56% hydroelectric and 44% thermal resources.

13 Illustration No. 1 below summarizes the present net
14 capability of Avista's owned generation resources:

1 **Illustration No. 1: Avista Generation**

Company-Owned Projects	MW
Noxon Rapids	557
Cabinet Gorge	255
Post Falls	18
Upper Falls	10
Monroe Street	15
Nine Mile	18
Long Lake	83
Little Falls	35
Total Hydroelectric Generation	991
Colstrip Units 3 and 4	222
Coyote Springs 2	278
Kettle Falls	50
Total Base-Load Thermal Generation	550
Northeast CT	56
Kettle Falls CT	7
Boulder Park	24
Rathdrum CT	149
Total Natural Gas Peaking Generation	236
Total Avista-Owned Generation	1,777

2
3 The Company currently has long-term contractual
4 rights for 128 MW of capability from Mid-Columbia
5 hydroelectric projects, owned and operated by the Public
6 Utility Districts of Chelan, Douglas and Grant Counties.
7 The Company has a contract for 35 MW of wind generation
8 capability from the Stateline Wind Project through March
9 2012, and also receives 100 aMW of energy from other firm
10 contracts through 2010. Avista has a long-term power

1 purchase agreement (PPA) in place entitling the Company to
2 dispatch, purchase fuel for and receive the power output
3 from the 275 MW Lancaster combined-cycle combustion
4 turbine project located in Rathdrum, Idaho.

5 **Q. Would you please provide a summary of Avista's**
6 **resource planning and power supply operations?**

7 A. Yes. Avista uses owned and contracted-for
8 resources to serve its load requirements. The Power
9 Supply section of the Energy Resources Department is
10 responsible for dispatch decisions related to those
11 resources with dispatch rights. The Department monitors
12 and routinely studies capacity and energy resource needs.
13 Short and medium-term wholesale transactions are used to
14 economically balance resources with load requirements.
15 Longer-term resource decisions such as new generation
16 resources, upgrades to existing resources, demand-side
17 management (DSM), and long-term contract purchases are
18 generally made in conjunction with the Integrated Resource
19 Plan (IRP) and Request for Proposals (RFP) processes.

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

22 A. With the recent addition of the 275 MW Lancaster
23 PPA to the Company's resource mix, Avista's 2009 electric

1 Integrated Resource Plan (IRP) shows forecasted annual
2 energy deficits beginning in 2018, and sustained annual
3 capacity deficits beginning in 2019.¹

4 These capacity and energy load/resource positions are
5 shown on pages 2-27 and 2-28, respectively of Exhibit No.
6 4, Schedule 2. However, our most recent energy load and
7 resource projection, which is attached as Exhibit No. 5,
8 Schedule 1 to Mr. Kalich's testimony, has pushed the
9 annual deficits out another year. Therefore, Avista's
10 current projection shows an annual energy deficit in 2019
11 of about 40 aMW, and the deficiency increases to 481 aMW
12 in 2029. The Company's capacity resource position is
13 currently projected to be surplus through 2019. Sustained
14 annual capacity deficiencies begin at 110 MW in 2020 and
15 increase to 732 MW in 2029.

16 **Q. How does the Company plan to meet future energy**
17 **and capacity needs beginning in 2019 and 2020,**
18 **respectively?**

19 A. The Company will pursue the Preferred Resource
20 Strategy described in the 2009 Electric IRP, which is
21 attached as Exhibit No. 4, Schedule 2. The IRP provides

¹ The Company has a 150 MW capacity exchange agreement with Portland General Electric that ends in December 2016 which results in short-term annual capacity deficits in 2015 and 2016. Sustained annual capacity deficits begin in 2019.

1 details about resource needs, specific cost and operating
2 characteristics of the resources evaluated for the
3 Preferred Resource Strategy, and the scenarios used for
4 resource evaluations.

5 The Company's 2009 Electric IRP was submitted to the
6 Commission in August 2009 following the completion of a
7 public process involving six Technical Advisory Committee
8 meetings. The IRP represents the preferred plan at a
9 point in time, however the Company will continue
10 evaluating resource options to meet future load
11 requirements, including medium-term market purchases,
12 generation ownership, hydroelectric upgrades, renewable
13 resources, distribution efficiencies, conservation
14 measures, long-term contracts, and generation lease or
15 tolling arrangements. As stated earlier, longer-term
16 resource decisions are generally made in conjunction with
17 the Company's IRP and RFP processes, although the Company
18 may acquire some resources outside of formal RFP
19 processes.

20 Avista's 2009 Preferred Resource Strategy includes 5
21 MWS of distribution efficiencies, 339 MWS of DSM, 5 MW of
22 upgrades to existing hydroelectric plants, 750 MWS of gas-
23 fired CCCT, and 350 MWS of wind located in the Pacific

1 Northwest. The timing of these resources as published in
 2 the 2009 IRP is shown in Illustration No. 2 below. The
 3 Company has recently decided to postpone the acquisition
 4 of Northwest Wind included in Illustration 2. I will
 5 explain this decision later in my testimony.

6 **Illustration No. 2:**

7 **2009 Electric IRP Preferred Resource Strategy**

Resource Type	By the End of	Nameplate (MW)	Energy (aMW)
Northwest Wind	2012	150.0	48.0
Distribution Efficiencies	2010 – 2015	5.0	2.7
Little Falls Upgrades	2013 – 2016	3.0	0.9
Northwest Wind	2019	150.0	50.0
CCCT	2019	250.0	225.0
Upper Falls Upgrade	2020	2.0	1.0
Northwest Wind	2022	50.0	17.0
CCCT	2024	250.0	225.0
CCCT	2027	250.0	225.0
Conservation	All Years	339.0	226.0
Total		1,449.0	1,020.6

8

9 **Q. What is the status of Avista's plans to meet the**
 10 **renewable portfolio standard (RPS) in Washington beginning**
 11 **in 2012?**

12 **A. The Energy Independence Act, RCW Chapter 19.285,**
 13 **resulting from Initiative 937 in the State of Washington,**
 14 **requires utilities with more than 25,000 customers to**
 15 **adhere to a renewable portfolio standard by meeting 3% of**

1 their load by 2012, 9% by 2016, and 15% by 2020 with
2 qualified renewable energy.

3 Avista plans to meet its RPS obligations in the near-
4 term through a combination of qualified hydroelectric
5 upgrades, and the purchase of renewable energy credits
6 (RECs). In March 2009 Avista purchased 5.7 aMW of credits
7 (RECs) per year from 2012 through 2015 to satisfy the RPS
8 requirement through 2015.

9 **Q. You mentioned earlier that Avista has postponed**
10 **the acquisition of wind generation in 2012. Why did the**
11 **Company choose to delay the addition of wind generation?**

12 A. The Company will need to add approximately 50 aMW
13 of additional qualifying renewable resources to meet the
14 nine percent (9%) RPS requirement at the beginning of 2016.
15 As Mr. Morris explained in his testimony, while there were
16 reasons to acquire additional renewable resources now, we
17 concluded that the near-term cost impacts to our customers
18 did not outweigh the uncertain long-term benefits of
19 acquiring it now.

20 If we were to acquire additional renewable resources
21 prior to the end of 2012 we could take advantage of a 30%
22 investment tax credit under the Federal Stimulus Package,
23 and also benefit from a Washington State sales tax credit of

1 7.7%. We issued a request for proposals on September 23,
2 2009 for up to 35 aMW of Washington RPS qualified renewable
3 energy. The RFP was intended to assess the opportunity to
4 take advantage of these state and federal tax incentives
5 that are currently available in the 2010 - 2012 timeframe.

6 Avista's proposed Reardan wind project is very
7 attractive compared with the proposals received through
8 the RFP process. The Company purchased the rights to
9 develop the wind project located near Reardan, Washington
10 from Energy Northwest in May 2008, and has added
11 additional leases with local landowners since that time.
12 The Reardan project site has permits and leases in place
13 and has been verified as a viable wind site through
14 several studies based on wind data collected at the site.
15 Current design plans call for a project capability of
16 approximately 90 MW.

17 On the other hand, as the law in Washington State
18 stands now, we do not need additional renewable energy
19 credits until 2016, and we do not need new energy
20 resources until 2019. And even with the tax credits, the
21 cost of power from the Reardan project would be 9 to 10
22 cents per kWh, which would have resulted in a rate
23 increase for our customers. The cost of the Project would

1 be over \$200 million, which is sizable in relation to our
2 current electric rate base of approximately \$1.6 billion.
3 So even though the Project is "on sale" now because of the
4 available tax credits, we concluded that the Company and
5 our customers simply cannot afford it at this time.

6 **Q. Will the Reardan Project still be available for**
7 **development after 2012?**

8 A. Yes. The Reardan site, including permits and
9 leases, is available and positioned to be constructed and
10 on line in the 2014 - 2015 timeframe. In addition, the
11 Company continues to place met towers at other locations
12 within its service territory to collect wind data and
13 explore other sites for potential development. The
14 Company anticipates that renewable resources necessary to
15 meet 2016 RPS requirements may come from a variety of
16 alternatives including those projects described above,
17 and/or from qualifying renewable third-party projects.
18 Other renewable energy options, including qualified plant
19 upgrades and REC purchases will also be considered.

20 **Q. Can you provide a high level summary of Avista's**
21 **risk management program for energy resources?**

22 A. Yes. Avista Utilities uses several techniques
23 to manage the risks associated with serving load and

1 managing Company-owned and controlled resources. The
2 Company's risk management approach uses price
3 diversification using a layering strategy for forward
4 purchases and sales. The Energy Resources Risk Policy
5 provides general guidance to manage the Company's energy
6 risk exposure relating to electric power and natural gas
7 resources over the long term (more than 36 months), the
8 short term (monthly and quarterly periods out to 36
9 months), and the immediate term (present month). The
10 period up to 18 months focuses on mechanically layering-in
11 purchases, as well as making advantageous purchases due to
12 declines in energy prices. The 18 to 36 month period
13 primarily looks for advantageous declines in price
14 movements based on models utilizing historic price
15 variability.

16 The Risk Policy is not a specific procurement plan
17 for buying or selling power or natural gas for generation
18 at any particular time, but is a guideline used by
19 management when making procurement decisions for electric
20 power and natural gas for generation. Several factors,
21 including the variability associated with loads,
22 hydroelectric generation, and electric power and natural
23 gas prices, are considered in the decision-making process

1 regarding procurement of electric power and natural gas
2 for generation. A copy of the current Energy Resources
3 Risk Policy is in Confidential Exhibit No. 4, Schedule 1C.

4 The use of the hedge scheduler approach, as outlined
5 in an appendix in the Risk Policy, describes what is
6 essentially a layering strategy aimed to average-in
7 purchases or sales of electric power and natural gas
8 generation fuel over a period of time. This approach aims
9 to smooth the impacts of price volatility in the energy
10 markets.

11

12

III. GENERATION CAPITAL PROJECTS

13 **Q. Please describe the upgrade projects for the**
14 **Noxon Rapids generating units.**

15 A. The Company is in the middle of a multi-year
16 program to upgrade the Noxon Rapids generating units which
17 are currently using 1950's era technology. The upgrades
18 on these four units are expected to improve efficiency by
19 adding an additional 30 MW of capacity and approximately 6
20 aMW of energy to the Noxon Rapids project, as well as
21 improve reliability. Illustration No. 4 below summarizes
22 the timing and additional capacity and efficiency gains of
23 these upgrades.

1

Illustration No. 4: Noxon Rapids Upgrades

Noxon Rapids Unit #	Schedule of Completion	Additional Capacity	Additional Efficiency
1	April 2009	7.5 MW	4.16%
3	April 2010	7.5 MW	4.15%
2	April 2011	7.5 MW	2.42%
4	April 2012	7.5 MW	1.49%

2

3 The Unit #1 work consisted of the replacement of the
4 stator core, rewinding the stator, installing a new
5 turbine and performing a complete mechanical overhaul.
6 This upgrade increased the Unit's energy efficiency by
7 4.16%, and increased the unit rating by 7.5 MW. The
8 upgrade also fixed several reliability concerns for the
9 Unit including mechanical vibration and stator age. This
10 work was completed in 2009. The costs and additional
11 generation of this project were pro formed, and approved
12 for recovery, in Case No.AVU-09-01.

13 The upgrade work on Units 3, 2 and 4 began in 2009
14 and will continue into 2012. The Unit #3 upgrade, planned
15 for completion in April 2010, is planned to increase
16 energy efficiency by 4.15%, and boost the unit rating 7.5
17 MW.

18 Unit #2 is scheduled to have a new turbine and
19 complete mechanical overhaul between August 2010 and April

1 2011. This upgrade is planned to increase Unit #2
2 efficiency 2.42% and boost the unit rating by 7.5 MW.

3 The upgrade work at Unit #4 involves the installation
4 of a new turbine and a complete mechanical overhaul from
5 August 2011 through April 2012. The Unit #4 upgrade is
6 planned to increase efficiency 1.49% and increase the unit
7 rating by 7.5 MW.

8 The costs associated with Unit #3, which will be
9 completed in April 2010, will total approximately \$9.3
10 million (system), and Unit #2, planned for completion in
11 April 2011, will cost approximately \$9.2 million (system),
12 as further described in Company witness Mr. DeFelice's
13 testimony. Company witness Ms. Andrews incorporates the
14 Idaho share of these costs in her adjustments. The costs
15 for the upgrade for Noxon Rapids Unit #4 has not been
16 included in this case, but will be included in future rate
17 proceedings.

18 **Q. Can you please provide a brief description of**
19 **the other generation-related capital projects that are**
20 **included in this case?**

21 A. Yes. The 2010 generation projects included in
22 the Company's case, as discussed by Mr. DeFelice, total
23 \$33.4 million (system). The 2010 Noxon Unit #3 upgrade

1 project discussed above makes up \$9.3 million of this
2 total. In addition, there are ten other areas of
3 generation capital projects totaling \$24.1 million as
4 discussed further below.

5 **Thermal - Kettle Falls Capital Projects - \$1,817,000**

6 The primary project at the Kettle Falls Generating Station
7 is replacement of the Air Heater. This will recover some
8 of the capacity that has been lost over the past several
9 years because of corrosion of air heater tubes and it will
10 reduce the overall load of the ID Fan Motor. Other
11 smaller projects at Kettle Falls include replacement of
12 the wood screw conveyors which feed wood into the hopper
13 and replacement of ash screws in the ash removal system.

14
15 **Thermal - Colstrip Capital Additions- \$2,275,000**

16 Colstrip capital additions in 2010 include a major waste
17 water treatment plant project for Units 3 and 4. This
18 project is an environmental requirement to reduce excess
19 water inventory in order to help reduce the water level in
20 the ponds, which will in turn help reduce the potential
21 for seepage and improve groundwater protection. A number
22 of other smaller capital projects will be performed,
23 including mercury control for Units 3 and 4 and the
24 replacement of an existing boiler retract with a new model
25 that has a more effective soot blower.

26
27 **Thermal - Other Small Projects - \$78,000**

28 Please refer to the workpapers of Mr. DeFelice for a
29 detailed listing of the projects included in this
30 category.

31
32 **Hydro - Nine Mile Upgrade - \$3,954,000**

33 This capital project entails the installation of a new
34 pneumatically operated spill gate on the Nine Mile
35 spillway section. This will improve operational
36 performance of the project by not requiring extended
37 operation at lower head as well as eliminate the annual
38 downstream risk associated with tripping wooden
39 flashboards. This project is a FERC license requirement.
40 This project will eliminate the need to install/remove the
41 flashboards on an annual basis, which creates savings of

1 approximately \$75,000 of O&M costs; these savings have
2 been reflected in the proposed revenue requirement.

3
4 **Hydro - Noxon Capital Project - \$7,551,000**

5 Replacements of the Generator Step up Transformers (GSU)
6 are needed to accommodate the additional capacity from the
7 turbine upgrades. These transformers are 50 years old and
8 were reaching the end of their useful life, without the
9 additional capacity requirements. The new GSU's will be
10 roughly 50% more efficient than the existing transformer,
11 saving a potential \$125,000 a year in loss reductions;
12 these savings have been reflected in the proposed revenue
13 requirement.

14
15 **Hydro - Clark Fork/Spokane Implement PM&E Agreements -**
16 **\$4,053,000**

17 Multiple projects on both river systems are planned for
18 2010 as part of the protection, mitigation and enhancement
19 (PM&E) plans. These projects were agreed to as part of
20 the Clark Fork settlement agreement and FERC license
21 received in 2001 and the Spokane settlement agreement and
22 FERC license received in 2009.

23
24 **Hydro - Other Small Projects - \$2,296,000**

25 There are a number of other small hydro project capital
26 improvements planned for 2010, including:

- 27 (1) Completing a system station sump control and
28 monitoring systems to facilitate anticipated license
29 conditions, and other small projects;
30 (2) Replacing a major component of the Cabinet Unit 1
31 Turbine (discharge ring);
32 (3) Replacing the roof at our Long Lake HED; and
33 (4) Completing the project to replace the old plant
34 controls and locate all new equipment from the Post
35 Street Substation to the Upper Falls plant. New
36 equipment will be installed to modernize the unit,
37 enhance the protection schemes, and to automate the plant
38 from the Generation Control Center. This will improve
39 the ability to control the plant and assist with river
40 flow requirements of the new Spokane FERC license.
41 Please refer to the workpapers of Mr. DeFelice for
42 detailed listing of these projects.

43
44 **Other - Coyote Springs 2 (CS2) Capital Projects -**
45 **\$1,197,000**

1 There are a number of project improvements planned for
2 2010, including the upgrade of the Attemperator valve,
3 which is part of the heat recovery steam generator, to
4 enhance steam temperature control and system reliability.
5 Other smaller projects planned for 2010 include the
6 replacement of heat exchangers, installation of ammonia
7 dilution heating equipment, battery replacement, and
8 several smaller PGE/Avista shared projects to improve
9 safety and reliability.

10

11 **Other - Boulder Park - \$410,000**

12 Generation capital projects at Boulder Park include the
13 replacement of the control network. The existing system
14 is obsolete and replacement parts are no longer available.

15

16 **Other Small Projects - \$493,000**

17 There are a number of project improvements planned for
18 2010. These projects include the upgrade of the control
19 system at the Northeast Combustion Turbine for standby
20 reserve. This project includes the construction of a new
21 building to house the control room and provide better
22 battery capacity for back up purposes. This project is
23 expected to improve the starting and running reliability
24 of this asset to better service our reserve requirements.
25 Please refer to the workpapers of Mr. DeFelice for
26 detailed listing of other projects in this category.

1 Ms. Andrews incorporates Idaho's share of these
2 capital project additions in her adjustments.

3 **IV. HYDRO RELICENSING**

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

7 A. Yes. Avista received a new 45-year FERC
8 operating license for its Cabinet Gorge and Noxon Rapids
9 hydroelectric generating facilities on the Clark Fork
10 River on March 1, 2001. The Company has continued to work
11 with the 27 signatories to the Clark Fork Settlement
12 Agreement to meet the goals, terms, and conditions of the
13 Protection, Mitigation and Enhancement (PM&E) measures
14 under the license. The implementation program, in
15 coordination with the Management Committee which oversees
16 the collaborative effort, has resulted in the protection
17 of approximately 2,620 acres of bull trout, wetlands,
18 uplands, and riparian habitat. The fish passage program,
19 using electrofishing and trapping with over 150 adults
20 radio tagged and their movements studied, has
21 reestablished bull trout connectivity between Lake Pend
22 Oreille and the Clark Fork River tributaries above Cabinet
23 Gorge Dam. Avista has worked with the U.S. Fish and

