

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-12\_\_\_\_\_

DIRECT TESTIMONY OF

ROBERT J. LAFFERTY

REPRESENTING AVISTA CORPORATION

**I. INTRODUCTION**

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

A. My name is Robert J. Lafferty. I am employed as the Director of Power Supply at Avista Corporation, located at 1411 East Mission Avenue, Spokane, Washington.

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

A. Yes. I received a Bachelor of Arts degree in Business Administration and a Bachelor of Science degree in Electrical Engineering from Washington State University, both in 1974. I began working as a distribution engineer for Avista in 1974 and held several different engineering positions with the Company. In 1979, I passed the Professional Engineering License examination in the state of Washington. I have held management positions in engineering, marketing, demand-side-management and energy resources. I began work in the Energy Resources Department in March 1996, and have held various positions involving the planning, acquisition and optimization of energy resources. I became the Director of Power Supply in March 2008, where 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 provides an overview of Avista's resource planning and power supply operations. This includes summaries of the Company's generation resources, the current and future load and resource position, future resource plans, and an update on the Company's plans regarding the acquisition of new renewable resources, including the power purchase agreement with Palouse Wind, LLC. As part of an overview of the Company's

1 risk management policy, I will provide an update on the Company's hedging practices. I  
 2 will address hydroelectric and thermal project upgrades, followed by an update on recent  
 3 developments regarding hydro licensing.

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

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

14 A. Yes. Exhibit No.\_\_\_\_(RJL-2) includes Avista's 2011 Electric Integrated  
 15 Resource Plan and Appendices, Exhibit No.\_\_\_\_(RJL-3) provides a forecast of Company  
 16 load and resource positions from 2013 through 2032. Confidential Exhibit No.\_\_\_\_(RJL-4C)  
 17 includes Avista's Energy Resources Risk Policy. Exhibit No.\_\_\_\_(RJL-5) is a Map of the  
 18 Palouse Wind Project. Exhibit No.\_\_\_\_(RJL-6) contains Avista's 2009 Electric Integrated  
 19 Resource Plan and Appendices. Confidential Exhibit No.\_\_\_\_(RJL-7C) includes the Palouse  
 20 Wind Board Involvement Documentation. Confidential Exhibit No.\_\_\_\_(RJL-8C) is the 2011  
 21 Renewables Request for Proposal Process and Results, and Confidential Exhibit  
 22 No.\_\_\_\_(RJL-9C) is the Palouse Wind Power Purchase Agreement.

23

24 **II. RESOURCE PLANNING AND POWER OPERATIONS**

25 **Q. Would you please provide a brief overview of Avista's owned-generating**  
 26 **resources?**

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

7           Illustration No. 1 below summarizes the present net capability of Avista’s owned-  
 8 generation resources:

9

10

**Illustration No. 1: Avista’s Owned-Generation**

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

11

12           **Q.     Would you please provide a brief overview of Avista’s major generation**  
 13 **contracts?**



1

**Illustration No. 3: Energy Contracts**

<b>Contract</b>	<b>Contract Type</b>	<b>End Date</b>	<b>Winter Capacity (MW)</b>	<b>Summer Capacity (MW)</b>	<b>2012 Annual Energy (aMW)</b>
<b>Clearwater</b>	PURPA	6/2013	75	75	52
<b>Douglas Settlement</b>	Purchase	9/2018	2	3	3
<b>Lancaster</b>	Purchase	10/2026	290	249	222
<b>Palouse Wind</b>	Purchase	12/2042	0	0	42
<b>Small Power</b>	PURPA	Varies	2	1	2
<b>Stateline</b>	Purchase	3/2014	0	0	9
<b>Stimson Lumber</b>	Purchase	11/2016	4	5	4
<b>Upriver (net load)</b>	Purchase	12/2011	8	-1	6
<b>Spokane Waste to Energy</b>	Purchase	12/2016	16	16	15
<b>WNP-3</b>	Purchase	6/2019	82	0	42
<b>Total</b>			<b>479</b>	<b>348</b>	<b>397</b>

2

3 **Q. Would you please provide a summary of Avista's power supply**  
4 **operations and acquisition of new resources?**

5 A. Yes. Avista uses a combination of owned and contracted-for resources to  
6 serve its load requirements. The Power Supply Department is responsible for dispatch  
7 decisions related to those resources for which the Company has dispatch rights. The  
8 Department monitors and routinely studies capacity and energy resource needs. Short- and  
9 medium-term wholesale transactions are used to economically balance resources with load  
10 requirements. Longer-term resource decisions such as the acquisition of new generation  
11 resources, upgrades to existing resources, demand-side management (DSM), and long-term  
12 contract purchases are generally guided by the Integrated Resource Plan (IRP) and will  
13 typically include a Request for Proposals (RFP) and/or other market due diligence process.

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

1           A.     Avista’s 2011 electric Integrated Resource Plan (IRP) shows forecasted  
2     annual energy deficits beginning in 2019, and sustained annual capacity deficits beginning  
3     in 2020.<sup>1</sup> These capacity and energy load/resource positions are shown on pages 2-27 and 2-  
4     29, respectively of Exhibit No.\_\_\_\_(RJL-2). Exhibit No.\_\_\_\_ (RJL-3) shows our most recent  
5     load and resource projection. Avista’s current projection shows an annual energy deficit  
6     beginning in 2019 of about 9 aMW, and increasing to a 467 aMW deficit in 2032. The  
7     Company’s January capacity resource position, based on an 18-hour peak event (6 hours per  
8     day and over 3 days), is currently projected to be surplus through 2022. Sustained annual  
9     capacity deficiencies, based on a January peak, begin at 76 MW in 2022 and increase to a  
10    656 MW deficit in 2032. The Company’s August capacity resource position, based on an  
11    18-hour peak event, is currently projected to be surplus through 2018. Sustained annual  
12    capacity deficiencies, based on an August peak, begin at 43 MW in 2019 and increase to a  
13    669 MW deficit in 2032.

14           **Q.     How does the Company plan to meet future energy and capacity needs**  
15    **beginning in 2020?**

16           A.     The Company will be guided by the 2011 Preferred Resource Strategy. The  
17    current Preferred Resource Strategy is described in the 2011 Electric IRP, which is attached  
18    as Exhibit No.\_\_\_\_(RJL-2). The IRP provides details about resource needs, specific resource  
19    costs, resource operating characteristics, and the scenarios used for evaluating the mix of  
20    resources for the Preferred Resource Strategy.

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<sup>1</sup> 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 2020.

1           The Company's 2011 Electric IRP was submitted to the Commission on August 26,  
2 2011, following the completion of a public process involving six Technical Advisory  
3 Committee meetings from May 27, 2010 through June 23, 2011. The Commission  
4 acknowledged the 2011 Electric IRP on January 12, 2012 in Docket No. UE-101482. The  
5 IRP represents the preferred plan at a point in time, however, the Company continues  
6 evaluating resource options to meet future load requirements, including, but not limited to,  
7 medium-term market purchases, participation in hydroelectric capacity auctions, generation  
8 ownership, hydroelectric upgrades, renewable resources, distribution efficiencies,  
9 conservation measures, long-term contracts, and generation lease or tolling arrangements in  
10 between IRPs. As stated earlier, longer-term resource decisions are generally made in  
11 conjunction with the Company's IRP and RFP processes, although the Company may  
12 acquire some resources outside of formal RFP processes.

13           Avista's 2011 Preferred Resource Strategy includes 28 MWs of distribution  
14 efficiencies, 419 MWs of cumulative energy efficiency, 4 MWs of upgrades to existing  
15 thermal plants, 752 MWs of natural gas fired plants (212 MWs of simple cycle and 540  
16 MWs of combined-cycle combustion turbine (CCCT)), and 240 MWs of nameplate wind  
17 located in the Pacific Northwest. The timing of these resources as published in the 2011 IRP  
18 is in Illustration No. 4 below.



1

**Illustration No. 4: 2011 Electric IRP Preferred Resource Strategy**

<b>Resource Type</b>	<b>By the End of Year</b>	<b>Nameplate (MW)</b>	<b>Energy (aMW)</b>
<b>Northwest Wind</b>	2012	120	35
<b>SCCT</b>	2018	83	75
<b>Thermal Upgrades</b>	2019	4	3
<b>Northwest Wind</b>	2019-2020	120	35
<b>SCCT</b>	2020	83	75
<b>CCCT</b>	2023	270	237
<b>CCCT</b>	2026	270	237
<b>SCCT</b>	2029	46	42
<b>Total</b>		996	739
<b>Efficiency Improvements</b>			
<b>Efficiency Improvements</b>	<b>By the End of Year</b>	<b>Peak Reduction (MW)</b>	<b>Energy (aMW)</b>
<b>Distribution Efficiencies</b>	2012-2031	28	13
<b>Energy Efficiency</b>	2012-2031	419	310
<b>Total Efficiency</b>		447	323

2

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

5 A. Yes. Avista Utilities uses several techniques to manage the risks associated  
6 with serving load and managing Company-owned and controlled resources. The Energy  
7 Resources Risk Policy provides general guidance to manage the Company's energy risk  
8 exposure relating to electric power and natural gas resources over the long-term (more than  
9 41 months), the short-term (monthly and quarterly periods up to approximately 41 months),  
10 and the immediate term (present month).

11 The Energy Resources Risk Policy is not a specific procurement plan for buying or  
12 selling power or natural gas at any particular time, but is a guideline used by management  
13 when making procurement decisions for electric power and natural gas fuel for generation.  
14 Several factors, including the variability associated with loads, hydroelectric generation, and

1 electric power and natural gas prices, are considered in the decision-making process  
2 regarding procurement of electric power and natural gas for generation.

3 The Company aims to strategically develop or acquire long-term energy resources as  
4 suggested by the Company's Integrated Resource Plan acquisition targets, while taking  
5 advantage of competitive opportunities to satisfy electric resource supply needs in the long-  
6 term period. On the other end of the time spectrum, electric power and fuel transactions in  
7 the immediate term are driven by a combination of factors that incorporate both economics  
8 and operations, including near-term market conditions (price and liquidity), generation  
9 economics, project license requirements, load and generation variability, reliability  
10 considerations, and other near-term operational factors.

11 For the short-term timeframe, which falls between the long-term and immediate term  
12 periods, the Company's Energy Resources Risk Policy guides its approach to hedging  
13 financially open forward positions. A financially open forward period position may be the  
14 result of either a short position situation, for which the Company has not yet purchased the  
15 fixed price fuel to generate, or alternatively purchased fixed price electric power from the  
16 market, to meet projected average load for the forward period or a long position, for which  
17 the Company has generation above its expected average load needs and has not yet made a  
18 fixed price sale of that surplus to the market in order to balance resources and loads.

19 The Company employs an Electric Hedging Plan to guide power supply position  
20 management in the short-term period. The Risk Policy Electric Hedging Plan is essentially a  
21 price diversification approach employing a layering strategy for forward purchases and sales  
22 of either natural gas fuel for generation or electric power in order to approach a generally  
23 balanced position against expected load as forward periods draw nearer.

1           **Q.     What is the status of Avista’s plans to meet the renewable portfolio**  
2 **standard (RPS) in Washington beginning in 2012?**

3           A.     The Energy Independence Act, RCW Chapter 19.285, resulting from  
4 Initiative 937, requires utilities with more than 25,000 customers to comply with a  
5 renewable portfolio standard by meeting 3% of their load by 2012, 9% by 2016, and 15% by  
6 2020 with qualified renewable energy generation or renewable energy credits.

7           Avista plans to meet its RPS obligations in the near-term with qualified hydroelectric  
8 upgrades, purchased RECs, wind generation, and qualifying biomass generation starting in  
9 2016. Illustration No. 5 below shows Avista’s projected net REC position from 2012  
10 through 2020 before applying the rollover provision. The RECs projected to be available to  
11 the Company as shown in Illustration No. 5 do not include the 20 percent apprenticeship  
12 credit for qualified hydroelectric upgrades. The Company is in the process of applying for  
13 certification of the apprenticeship credit for the upgrades at the Noxon Rapids Hydroelectric  
14 Project. The amount of projected RECs available will increase if the apprenticeship credit is  
15 approved for the qualified hydroelectric projects. RECs associated with the Palouse Wind  
16 project include the apprenticeship credit. The last column in Illustration No. 5 shows the  
17 Company’s net REC needs.

18  
19  
20  
21  
22  
23

1                   **Illustration No. 5: Washington Renewable Portfolio Standard Requirements in**  
 2                   **aMW of RECs before Banking**  
 3

<b>Year</b>	<b>Percentage of WA Load</b>	<b>Total Projected Need</b>	<b>Qualifying Hydro</b>	<b>Qualifying Resources and RECs</b>	<b>Surplus/ (Deficiency)</b>
<b>2012</b>	3%	19.0	21.3	4.0	6.3
<b>2013</b>	3%	19.4	21.9	47.9	50.4
<b>2014</b>	3%	19.7	22.0	47.9	55.8
<b>2015</b>	3%	19.8	22.0	53.6	44.7
<b>2016</b>	9%	60.0	25.7	79.0	46.4
<b>2017</b>	9%	60.7	25.7	81.4	46.4
<b>2018</b>	9%	61.4	25.7	79.9	44.2
<b>2019</b>	9%	62.0	25.7	80.4	44.1
<b>2020</b>	15%	104.3	25.7	81.4	2.8

4

5                   **Q. Has the Company made any adjustments to its REC portfolio as it looks**  
 6 **forward toward meeting its Energy Independence Act targets for renewable energy?**

7                   A. Yes, the Company sold the 5.7 aMW of qualifying RECs for years 2012  
 8 through 2014 in January 2012. 5.7 aMW of RECs were purchased in 2008 for the 2012 to  
 9 2015 period. The qualifying RECs purchased for 2015 have been retained because they  
 10 could be carried forward for the 2016 compliance year, in which REC requirements increase  
 11 from three to nine percent of Washington load. In 2011, the 2012-2014 RECs were  
 12 determined to be surplus based on a number of factors including decreased load projections,  
 13 the acquisition of the Palouse Wind Power Purchase Agreement, and recent decisions  
 14 concerning the determination of the amount of qualifying hydroelectric upgrades. The RPS  
 15 amounts reported in Avista's general rate case (Docket No. UE-110876) included an  
 16 allowance for bad hydroelectric years, which are no longer required, because the subsequent  
 17 determinations about the calculation of qualifying hydroelectric upgrades in the Renewable

1 Portfolio Standard Work Group (UE-110523) allow for the use of average streamflow in the  
2 calculations.

3

4 **III. PALOUSE WIND POWER PURCHASE AGREEMENT ACQUISITION**

5

6 **Q. Please explain the Palouse Wind Power Purchase Agreement and what**  
7 **was the need for that resource?**

8 A. The Palouse Wind Power Purchase Agreement (Palouse Wind PPA) is a 30-  
9 year agreement to purchase all of the generation output and all environmental benefits  
10 associated with the Palouse Wind, LLC wind power project. The agreement also includes a  
11 purchase option after year ten. Avista's 2009 Integrated Resource Plan (IRP) indicated an  
12 approximate need for 50 aMW of qualifying renewable energy credits prior to 2016 in order  
13 to meet Washington's renewable portfolio standard (RPS). In early 2011, the 2011 IRP was  
14 well into development and identified a slightly lower need level of 42 aMW of qualifying  
15 renewable energy credits. In February 2011, Avista decided to issue a request for proposals  
16 (RFP) that would meet the Company's 2016 need for qualifying renewable energy credits  
17 prior to the December 31, 2012 expiration of federal and state tax incentives and other  
18 benefits, and also take advantage of the low equipment and construction costs that appeared  
19 to be available at the time.

20 **Q. Please briefly describe the Palouse Wind Project.**

21 A. The Palouse Wind Project will consist of 58 Vestas 1.8 MW wind turbines  
22 that will be located between Oakesdale, Washington and State Route 195 and with a total  
23 capacity of approximately 105 MWs. The project will be directly connected to the Avista

1 electric system and is expected to begin commercial operation towards the end of 2012.  
2 Exhibit No.\_\_\_\_(RJL-5) contains a map showing the location of the project.

3 **Q. Can you provide a simplified timeline of events leading up to the**  
4 **execution of the Palouse Wind PPA?**

5 A. Yes. The following list is a timeline of the major events leading up to the  
6 execution of the Palouse Wind PPA:

7 **December 2010 to February 2012:** Received unsolicited indicative pricing  
8 proposals from wind developers with projects under development.

9 **February 22, 2011:** RFP [See Confidential Exhibit No.\_\_\_\_(RJL-8C), Appendix 1].

10 **March 7, 2011:** Proposals to the 2011 RFP were opened. [See Confidential Exhibit  
11 No.\_\_\_\_(RJL-8C)].

12 **March 11, 2011:** WUTC Staff updated on preliminary RFP results. [See  
13 Confidential Exhibit No.\_\_\_\_(RJL-8C), Appendix 4].

14 **March 14, 2011:** Internal presentation of preliminary RFP results. [See Confidential  
15 Exhibit No.\_\_\_\_(RJL-8C), Appendix 4].

16 **March 17, 2011:** IPUC Staff updated on preliminary RFP results. [See Confidential  
17 Exhibit No.\_\_\_\_(RJL-8C), Appendix 4].

18 **May 12, 2011:** RFP Update Presentation to the Board Finance Committee. [See  
19 Confidential Exhibit No.\_\_\_\_(RJL-7C)].

20 **May 13, 2011:** RFP Update Presentation to Board about RFP. Received Board  
21 authorization to enter into negotiations with Palouse Wind for a PPA. [See  
22 Confidential Exhibit No.\_\_\_\_(RJL-7C)]

1           **June 28, 2011:** Authorization from Board Finance Committee. [See Confidential  
2           Exhibit No.\_\_\_\_(RJL-9C)]. Execution of Palouse Wind Power Purchase Agreement.

3           [See Confidential Exhibit No.\_\_\_\_(RJL-9C)]

4           **August 18, 2011:** First Amendment to the Palouse Wind PPA. [See Confidential  
5           Exhibit No.\_\_\_\_(RJL-9C)]

6           **November 14, 2011:** Second Amendment to the Palouse Wind PPA. [See  
7           Confidential Exhibit No.\_\_\_\_(RJL-9C)]

8           **December 19, 2011:** Third Amendment to the Palouse Wind PPA. [See  
9           Confidential Exhibit No.\_\_\_\_(RJL-9C)]

10          **Q. Can you provide some background regarding why the Company**  
11          **initiated an RFP for renewable resources in 2011.**

12          A. Yes. The Company had a need for RPS qualified renewable energy  
13          beginning in 2016. Avista had continued to monitor renewable resource market conditions,  
14          particularly with respect to projects bid into its 2009 renewable resource RFP after the  
15          Company decided not to select a resource out of that process. In late 2010 and early 2011,  
16          Avista was made aware of a significant drop in prospective project costs associated with  
17          construction of new wind generation facilities that were still in position to be constructed  
18          soon and also take advantage of available near-term tax incentives for projects brought on-  
19          line prior to December 31, 2012. The material drop in project cost, the availability of  
20          significant known tax advantages for renewable resource projects constructed prior to  
21          December 31, 2012, and the Report And Policy Statement Concerning Acquisition Of  
22          Renewable Resources By Investor-Owned Utilities (Docket No. UE-100849), were factors  
23          considered in the Company’s decision to issue a new request for proposals (RFP) for up to

1 35 aMW of renewable energy in February 2011. The 2011 renewable resource RFP sought  
2 qualifying projects or project output for the 2012 – 2032 time period. Avista stated in the  
3 RFP that Avista would not submit a self-build option. Analysis indicated that the  
4 combination of the significant drop in project cost and the substantial tax incentives  
5 available for renewable projects completed by December 31, 2012 yielded long-term  
6 benefits for customers compared to waiting until 2016 when RPS goals increase, tax  
7 incentives, attractive project pricing, and particular attractive wind project sites may no  
8 longer be available to Avista.

9 **Q. What are the prudence standards applied by this Commission related to**  
10 **the acquisition of a resource?**

11 A. The Commission articulated in PacifiCorp’s rate proceeding (Docket No.  
12 UE-090205) the four main questions that must be answered in order to support the  
13 acquisition of a generation resource as “prudent and used and useful in providing service to  
14 customers in Washington” (see Order No. 09, p. 23):

15  
16 When examining the acquisition of new facilities, we consider whether: (1)  
17 the new resources are necessary; (2) the Company evaluated and considered  
18 alternatives; (3) the acquisition decision involved the Board of Directors; and  
19 (4) whether the Company’s analysis and decision-making process is  
20 adequately documented. In addition, new power resources must comply with  
21 all state laws including the RCW 80.80 Greenhouse Gas Emissions  
22 Performance Standard.  
23

24 The four main considerations regarding prudence are discussed in order below.

25

26 **1. Resource Necessity**

27



1           **Q.    At the time of the 2011 RFP, please explain how the Company**  
 2 **determined that a new resource was necessary.**

3           A.    The need for the type and size of resource provided by the Palouse Wind  
 4 PPA was demonstrated in the 2009 Integrated Resource Planning process. (See Exhibit  
 5 No.\_\_\_\_(RJL-6)) The need was also confirmed in the 2011 IRP, which was nearing  
 6 completion when the Palouse Wind PPA was executed. (See Exhibit No.\_\_\_\_(RJL-2)) The  
 7 Company's 2009 IRP, developed in conjunction with the Technical Advisory Committee,  
 8 showed that Avista's first annual energy needs would occur in 2018 and sustained capacity  
 9 need in 2019. The first projected annual REC need of 48.1 aMW identified in the 2009 IRP  
 10 occurred in 2016. Illustration No. 6 shows Avista's projected energy needs, capacity needs,  
 11 and REC needs presented in the 2009 IRP.

12

13

**Illustration No. 6: 2009 IRP Load, Resource, and REC Tabulations**

<b>Net Position</b>	<b>2010</b>	<b>2011</b>	<b>2012</b>	<b>2013</b>	<b>2014</b>	<b>2015</b>	<b>2016</b>	<b>2017</b>	<b>2018</b>	<b>2019</b>
<b>Energy (aMW)</b>	309	185	123	110	93	59	38	31	(27)	(35)
<b>Capacity (MW)</b>	293	124	53	31	0	(45)	(74)	45	11	(46)
<b>REC Need (aMW)</b>	19.0	19.9	0.3	2.2	2.0	1.7	(48.1)	(49.1)	(50.3)	(51.6)

14

15           **Q.    How did the Company determine the amount and type of resource**  
 16 **needed?**

17           A.    The Company's energy, capacity and REC needs were used as inputs to the  
 18 development of the Preferred Resource Strategy (PRS). The PRS is developed using a

1 proprietary linear programming model called PRiSM. The PRiSM model helps select the  
2 PRS and uses:

- 3 1. load deficits (energy and capacity);
- 4 2. RPS requirements;
- 5 3. Avista's existing portfolio's costs (loads and resources) and operating  
6 margins (resources);
- 7 4. Fixed operating costs, return on capital, interest and taxes for each resource  
8 option;
- 9 5. Generation levels for existing resources and new resource options; and
- 10 6. Carbon emissions levels for existing resources and new resource options.

11 Additional details about the development of the PRS and the PRiSM model can be found in  
12 Chapter 8 of the 2009 IRP (Exhibit No.\_\_\_\_(RJL-6)). The 2011 IRP used a similar  
13 methodology and an updated version of the PRiSM model to develop the 2011 PRS can be  
14 found in Exhibit No.\_\_\_\_(RJL-2).

15 **Q. Is this resource consistent with the 2009 Preferred Resource Strategy?**

16 A. Yes. The 2009 PRS indicated a need for 48.0 aMW of energy/qualifying  
17 RECs in 2012 represented by 150 MW of nameplate wind capacity. At the time of the 2011  
18 RFP, work was also well underway in the 2011 IRP. The PRS in the Company's 2011 IRP  
19 reaffirmed the need for qualifying renewable resources in 2012 with requirements for 35.0  
20 aMW of qualifying renewable energy obtained through 120 MW of nameplate wind  
21 capacity located in the Northwest. A somewhat lower need for qualifying RECS in the form  
22 of wind generation in the 2011 IRP was indicated based on a lower load forecast as

1 compared to the 2009 IRP and a change in planning margin criteria. A higher expected  
2 capacity factor reduced further the equivalent nameplate wind capacity required.

3 **Q. Were there other circumstances that influenced the timing of the 2011**  
4 **renewable resource RFP?**

5 A. Yes. Avista's 2009 Electric Integrated Resource Plan (IRP) indicated a need  
6 for 48.1 aMW of qualifying renewable energy credits prior to 2016 to meet Washington's  
7 renewable portfolio standard (RPS) under the Energy Independence Act (19.285 RCW).  
8 After the 2009 IRP was completed, Avista issued a renewable request for proposal (RFP) in  
9 the third quarter of 2009 to acquire projects to meet these renewable energy requirements  
10 before 2016 and to take advantage of certain tax credits and other near-term benefits. In  
11 early 2010, the Company decided not to move forward with acquiring a resource from the  
12 2009 RFP process because the uncertain long-term benefits of early acquisition of a  
13 renewable resource did not outweigh the near-term cost impacts to customers given the  
14 information available at that time.

15 Subsequently, in early 2011, the draft 2011 IRP indicated a reduced REC need in  
16 2016 because of load reductions and a change in planning margin criteria. The projected  
17 new level of renewable energy credit need was estimated to be 42 aMW. Furthermore,  
18 information from the wind development market indicated that the price of wind turbines has  
19 declined. Following the termination of the 2009 RFP process, the Company continued to  
20 receive project and cost updates from some of the RFP bid developers and from other  
21 projects. In early 2011, indications were that wind turbine prices and project construction  
22 costs were declining significantly. Avista made the decision to move forward with an RFP  
23 to help meet the Company's 2016 need and to take advantage of the substantially reduced

1 equipment and construction costs prior to the December 31, 2012 expiration of federal and  
2 state tax incentives and other benefits.

3

4 **2. Evaluation and Consideration of Alternatives**

5

6 **Q. How did Avista evaluate and consider alternatives to the Palouse Wind**  
7 **PPA?**

8 A. The Company issued an RFP in February 2011, for 35 aMW of Washington  
9 RPS qualified renewable energy to be online by the end of 2012. (See Confidential Exhibit  
10 No.\_\_(RJL-8C)). The Company indicated in the RFP that a self-build option would not be  
11 included in the RFP process. The fast-track nature of the 2011 RFP did not allow for  
12 sufficient time for the Company to secure equipment and construction bids for a project at  
13 the Company-owned Reardan site that would fit into the RFP timeline and meet the  
14 December 31, 2012 federal tax credit deadline.

15 On March 7, 2011, the Company received eleven proposals totaling 774 MW in  
16 response to the RFP. The proposals included 769 MW of wind and 5 MW of landfill gas.  
17 The Company evaluated potential projects both quantitatively and qualitatively against one  
18 another based on predetermined criteria that had been vetted with the Idaho and Washington  
19 Commission Staffs. Analysis demonstrated that the highest ranked bid was the Palouse  
20 Wind Project. The Palouse Wind proposal was for an approximately 100 MW project  
21 located near Avista's Transmission System (30 miles south of Spokane, Washington) and  
22 with an expected 39.5 percent capacity factor (estimated to be about 38.4 aMW to 39 aMW  
23 depending upon final turbine selection and configuration). The project committed to reach

1 commercial operation by the end of 2012 to qualify for federal tax benefits. The project  
2 developer indicated they would also make best efforts to qualify for the 20 percent  
3 apprenticeship credit. The project was estimated to produce approximately 46 aMW of  
4 Washington-qualifying RECs, when including the apprenticeship credits.

5 The RFP evaluation process included two screening levels which resulted in a short list  
6 of four bidders. After completion of due diligence of the short-listed projects, the Palouse  
7 Wind Project was the highest overall ranked resource.

8 **Q. How was transmission considered in this decision?**

9 A. The Palouse Wind Project will be directly interconnected to Avista's system,  
10 so no third-party transmission is required for this project to serve our customers. At the time  
11 of the RFP, Palouse Wind had made an interconnection request, and received project scope  
12 and cost information from Avista transmission. Subsequently, Palouse Wind has signed a  
13 contract for the construction of Avista transmission required for interconnection. The  
14 evaluation process included the transmission interconnection cost in the case of projects  
15 with proposed direct interconnection with the Avista transmission system or transmission  
16 and losses for projects proposed to interconnect to third party transmission systems and  
17 wheeling power to the Avista system.

18

19

### **3. Board of Directors Involvement**

20 **Q. Was Avista's Board of Directors involved with the acquisition of the**  
21 **Palouse Wind PPA by Avista Utilities?**

22 A. Yes. The Company's Board of Directors was apprised of the 2011  
23 Renewables RFP and the evaluation process that was used to compare project bids from

1 which the Palouse Wind PPA was selected. Documentation of Board involvement regarding  
2 the Palouse Wind PPA is provided in Confidential Exhibit No.\_\_(RJL-7C). This  
3 Confidential Exhibit includes presentations made to the Board of Directors regarding the  
4 Palouse Wind PPA, relevant excerpts of Board minutes, as well as the Palouse Wind RFP  
5 Board Resolution.

6

7

**4. Documentation of Analysis and the Decision-Making Process**

8 **Q. What documentation for the analysis and decision-making process has**  
9 **the Company provided regarding the decision to enter into a contract for the Palouse**  
10 **Wind Project?**

11 A. The documentation provided concerning the analysis and decision-making  
12 process regarding the decision to execute a contract for the Palouse Wind Project are  
13 included in the following: Exhibit No.\_\_(RJL-2) includes Avista’s 2011 Electric  
14 Integrated Resource Plan and Appendices; Exhibit No. \_\_\_\_(RJL-5) is a map of the location  
15 of the Palouse Wind Project; Exhibit No.\_\_(RJL-6) is Avista’s 2009 Electric Integrated  
16 Resource Plan and Appendices; Confidential Exhibit No.\_\_(RJL-7C) provides the Palouse  
17 Wind Board documentation; Confidential Exhibit No.\_\_(RJL-8C) provides details about  
18 the 2011 Renewables Request for Proposal process and results; and Confidential Exhibit  
19 No.\_\_(RJL-9C) contains the Palouse Wind Power Purchase Agreement.

20 **Q. Does the Company believe that it has met the criteria and provided the**  
21 **requisite information to show that the Palouse Wind PPA was a prudent acquisition?**

22 A. Yes. My testimony and exhibits provide the documentation necessary to  
23 demonstrate the long-term need for the Palouse Wind PPA and provide specific supportive

1 details regarding the Company’s analysis. The Palouse Wind PPA is necessary to serve  
2 customer loads and meet Washington’s renewable portfolio standard, and is consistent with  
3 the Preferred Resource Strategy in the Company’s 2011 Electric IRP, which is discussed  
4 earlier in my testimony. The Board of Directors agreed with the recommendation to issue  
5 the RFP for 35 aMW of RPS-qualified renewable energy in 2011 and then subsequently  
6 approved the recommendation to negotiate a PPA with Palouse Wind, LLC under terms and  
7 conditions consistent with their bid proposal. The Company has provided and explained all  
8 of the analytical work that was completed related to this acquisition.

9 **Q. Is the Palouse Wind Power Purchase Agreement subject to the**  
10 **Greenhouse Gases Emissions Performance Standard detailed in RCW 80.80 and WAC**  
11 **480-100-415?**

12 A. No, the Company does not believe that the Palouse Wind PPA is subject to  
13 Washington’s Greenhouse Gas Emissions Performance Standard. Even though the PPA is a  
14 new long-term contract greater than five years for Avista Utilities, the PPA does not meet  
15 the standard of being a baseload electric generation facility under RCW 80.80.010 (4) since  
16 the facility is not projected or intended to operate at an annual capacity factor of at least 60  
17 percent. The annual capacity factor of Palouse Wind is approximately 40 percent. Even if  
18 the Palouse Wind Project were operated as a baseload facility (i.e., and annual capacity  
19 factor of 60 percent or greater), it would, nevertheless, be “... deemed to be in compliance  
20 with the greenhouse gas emissions performance standard ...” under RCW 80.80.040 (4)  
21 since wind generation is classified as a renewable resource under RCW 19.280.020, and  
22 therefore not subject to the Emissions Performance Standard.

23

1 **IV. GENERATION CAPITAL PROJECTS**

2 **Q. Please describe the upgrade projects for the Noxon Rapids generating**  
3 **units.**

4 A. The Company is at the final stage of a multi-year program to upgrade the  
5 Noxon Rapids generating units from 1950's era technology. Once completed, the upgrades  
6 on these four units are expected to improve reliability and increase efficiency, by adding 30  
7 MW of additional capacity and approximately 6 aMW of energy to the Noxon Rapids  
8 project. Illustration No. 7 summarizes the upgrade schedule, additional capacity and  
9 efficiency gains of these upgrades by unit.

10  
11 **Illustration No. 7: Noxon Rapids Upgrades**

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

12  
13 The Noxon Unit #1 work consisted of the replacement of the stator core, rewinding  
14 the stator, installing a new turbine and performing a complete mechanical overhaul. This  
15 upgrade increased the Unit's energy efficiency by 4.16%, and increased the unit rating by  
16 7.5 MW. The upgrade also fixed several reliability concerns for the Unit including  
17 mechanical vibration and stator age. This work was completed in 2009. The costs and  
18 additional generation of this project were approved for recovery in Docket No. UE-080416.



1           The Noxon Unit #3 upgrade, completed in May 2010, increased energy efficiency by  
2 4.15%, and improved the unit rating by 7.5 MW. The costs and additional generation for  
3 Unit #3 were approved for recovery in Docket No. UE-090134.

4           The Noxon Unit #2 upgrade, completed in May 2011, included a new turbine and  
5 complete mechanical overhaul. This upgrade increased the efficiency of Unit #2 by 2.42%  
6 and increased the unit rating by 7.5 MW. The costs and additional generation for Unit #2  
7 were approved for recovery in Docket No. UE-100467.

8           The Noxon Unit #4 upgrade is scheduled for completion in May 2012. The Unit #4  
9 upgrade will cost approximately \$8.3 million (system). The increased generating capability  
10 from these units is reflected in Mr. Kalich's AURORA<sub>XMP</sub> modeling of pro forma power  
11 supply costs for the test period.

12           The upgrade work at Noxon Unit #4, which is the final project in the Noxon  
13 upgrades, involves the installation of a new turbine, a complete mechanical overhaul, and  
14 GSU upgrades. The project started in August 2011 and is scheduled for completion in May  
15 2012. The Unit #4 upgrade is projected to increase efficiency by 1.49 percent and increased  
16 the unit capacity rating by 7.5 MW. The costs and additional generation for Unit #4 were  
17 included in the Company's 2011 general rate case (Docket No. UE-110876).

18           **Q.     Would you please provide a brief description of the capital projects at**  
19 **Coyote Springs 2?**

20           A.     Yes. There are four main capital projects planned for at Coyote Springs 2  
21 (CS2) which total \$3,804,000 (system). The first project involves the installation of a  
22 hydrogen generator. The electrical generators for both the Gas Turbine and the Steam  
23 Turbine are cooled by hydrogen gas. Even though this is a closed system, some hydrogen

1 gas does escape the system and make-up gas must be added so the generator operates  
2 properly. An evaluation was performed and it was determined that it would be cost-  
3 effective to install a hydrogen gas generator at the plant to create the necessary make-up gas  
4 for generator cooling purposes, instead of purchasing hydrogen gas.

5 The second capital project at Coyote Springs 2 replaces the Steam Turbine Generator  
6 Exciter. The existing excitation system was provided as original equipment from Alstom,  
7 who no longer supports this system. The only service providers available to provide  
8 assistance are located in Europe. This project will replace the Alstom unit with a GE unit  
9 that is compatible with the other excitation system in the plant, which will minimize spare  
10 parts requirements and capitalize on staff expertise.

11 The third capital project is the Gas Turbine Compressor Upgrade. The GE 7EA  
12 turbine compressor series currently installed at CS2 has exhibited an embedded risk due to  
13 failure of a section of the compressor blades. This project will install a set of GE supplied  
14 compressor blades to address this concern. All three of these capital projects at CS2 are  
15 expected to be in service by July of 2012.

16 The last CS2 capital project is the major overhaul on the steam and gas turbines  
17 being performed by GE under the long term service agreement (LTSA). This part of the  
18 capital projects at CS2 will be \$8,945,000, and the project is expected to be completed in  
19 June of 2012.

20 **Q. Would you please provide a brief description of the other generation-**  
21 **related capital projects that are planned for in 2012 and 2013?**

22 A. Yes. As shown in Illustration No. 8, the total 2012 and 2013 generation  
23 projects to be completed, as discussed by Mr. DeFelice, total \$47.2 million and \$21.8

1 million, respectively on a system basis. The 2012 Noxon Unit #4 upgrade project discussed  
 2 above is \$8.3 million of this total and the capital projects at Coyote Springs 2 are \$12.7  
 3 million. In addition, there are 11 other generation capital projects totaling \$48 million as  
 4 discussed further below.

5

6

**Illustration No. 8: Generation Capital Projects Summary**

<b>Project Name</b>	<b>2012 Capital Costs (000's)</b>	<b>2013 Capital Costs (000's)</b>
<b>Noxon Rapids Unit #4 Upgrade</b>	\$8,300	\$0
<b>Coyote Springs 2 Capital Projects</b>	\$3,804	\$0
<b>Coyote Springs 2 LTSA</b>	\$8,945	\$0
<b>Colstrip</b>	\$2,900	\$9,740
<b>Rathdrum CT</b>	\$0	\$917
<b>Base Hydro</b>	\$1,427	\$800
<b>Regulating Hydro Program</b>	\$2,908	\$1,900
<b>Kettle Falls Capital Projects</b>	\$3,622	\$960
<b>Little Falls Powerhouse Redevelopment</b>	\$3,300	\$767
<b>Post Falls Intake Gate Replacement</b>	\$4,600	\$0
<b>Nine Mile Redevelopment</b>	\$0	\$2,800
<b>Clark Fork Implementation PM&amp;E Agreement</b>	\$3,883	\$3,453
<b>Spokane River Implementation (PM&amp;E)</b>	\$3,260	\$240
<b>Other Small Capital Projects</b>	\$294	\$240
<b>Totals</b>	<b>\$47,243</b>	<b>\$21,817</b>

7

8 **Thermal – Colstrip Capital Additions: \$12,640,000 (\$2,900,000 in 2012 and \$9,740,000**  
 9 **in 2013)**

10 Capital work projects at Colstrip includes bushing and blower replacement, rewind spare  
 11 rotor, prototype scrubber polishing system to improve particulate removal, raise the ash  
 12 storage pond dam walls, materials for waterwall replacement, materials for final superheat  
 13 replacement, and miscellaneous small projects.

14

15 **Thermal – Rathdrum CT: \$917,000 in 2013**

16 In 2007, the Mark V controller on Rathdrum Unit 2 failed, taking the unit out of service for  
 17 several months. A new Mark VI controller was installed in its place. This project replaces  
 18 the old Mark V controller in Unit 1 with a Mark VI controller to match Unit 2. The Mark V  
 19 technology in Unit 1 is at the end of its life, is minimally supported by the manufacturer, and  
 20 is a better solution for our operations.

1  
2 **Hydro – Base Hydro Capital Project: \$2,227,000 (\$1,427,000 in 2012 and \$800,000 in**  
3 **2013)**

4  
5 **Generation Control Center Remodel:** The present generation control center  
6 utilizes technology that is more than 15 years old to display, control, and monitor all  
7 of Avista’s generation facilities. This includes controlling seven of the generating  
8 plants directly, while closely monitoring the six other plants. The new control room  
9 will provide for more efficient movement of operators for control of the plant, lay  
10 down space for drawings to assist with operation, local storage of manuals and other  
11 data, and an updated and more efficient HVAC system. This project is expected to  
12 be completed in July of 2012 at a cost of \$330,000.

13  
14 **Upper Falls HED Multi-Functional Landing:** Over time, the development of River  
15 Front Park and businesses along the Spokane River have reduced accessibility to the  
16 river for maintenance work for our Upper Falls Facilities. This includes the dam  
17 safety barrier, spillgates for Upper Falls (commonly referred to as the Control  
18 Works), and the emergency generator located near the spillgates for backup power  
19 purposes. This project is to construct a permanent landing near the Control Works  
20 that will allow barges and equipment to be set in the water to maintain these key  
21 facilities. Completion of this project is expected in April of 2012 at a cost of  
22 \$297,000.

23  
24 **Various Small Projects: \$800,000 in 2013**

25  
26 **Hydro – Regulating Hydro Program Capital Projects: \$4,808,000 (\$2,908,000 in 2012**  
27 **and \$1,900,000 in 2013)**

28  
29 **Install Rack and Forebay Monitoring at Long Lake HED:** This work is to install  
30 monitoring systems allowing operators to monitor forebay, tailwater, total dissolved  
31 gas, and dissolved oxygen levels. All of these systems involve installation of  
32 upstream or downstream instruments in common locations to monitor the water  
33 levels and quality. This project involves work required by the FERC license and to  
34 enhance dam safety. This project is expected to be completed in December of 2012  
35 at a cost of \$780,000.

36  
37 **Replace Powerhouse Lighting at Long Lake HED:** The current lighting system at  
38 the Long Lake powerhouse consists of 1,000 watt incandescent lamps, which are no  
39 longer commercially available and provide relatively poor quality lighting. This  
40 project will improve work lighting and put a more efficient lighting system in the  
41 powerhouse. The project should be completed in November of 2012 at a cost of  
42 \$228,000.

43  
44 **Sewage Disposal System at Cabinet Gorge HED:** The existing sewage disposal  
45 system at Cabinet Gorge is not able to maintain the effluent within permitted levels

1 and needs to be replaced with a system that will comply with all permits. This  
2 projected should be completed in November of 2012 at a cost of \$700,000.  
3

4 **Replace Station Air Compressors at Cabinet Gorge HED:** The existing three  
5 station air compressors at Cabinet Gorge are all original equipment. The air  
6 compressors have been overhauled and re-bored several times, but the bore wall  
7 thickness has been thinned to a point where another overhaul is not recommended.  
8 Due to the fragile condition of these compressors, blow down capabilities at Cabinet  
9 Gorge have been curtailed, reducing the amount of spinning reserve we can provide  
10 to serve our needs. This project is expected to be completed in June of 2013 at a cost  
11 of \$900,000.  
12

13 **Unit 5 Excitation System Replacement at Noxon Rapids HED:.** The existing  
14 exciter system from 1979 is obsolete. Parts are no longer available and we have had  
15 several forced outages on a variety of components over the past five to seven years.  
16 Further, the control scheme does not allow automatic control of the unit. This  
17 project will replace the system with a new bus-fed excitation system that meets  
18 NERC and operational expectations. This project is expected to be completed in  
19 November of 2013 at a cost of \$150,000.  
20

21 **Noxon Rapids Living Facility Additions:** With the ongoing work at Noxon Rapids  
22 and in the Clark Fork area to serve both the construction work at the plants and in  
23 support of the environmental office, additional living and meeting space is being  
24 planned for the Noxon Living Facility to support this ongoing work. The cost for the  
25 part of this project expected for completion in December of 2012 is \$800,000 and the  
26 cost for the part expected to be completed in December of 2013 is \$600,000.  
27

28 **Other Small Projects: \$650,000 (\$400,000 in 2012, \$250,000 in 2013)**  
29

30 **Thermal – Kettle Falls Capital Projects: \$4,582,000 (\$2,908,000 in 2012, \$960,000 in  
31 2013)**  
32

33 **Replace Turbine Controls:** The existing turbine control system (Distributed  
34 Control System or DCS) is part of the original plant equipment. Over the past  
35 decade, we have been replacing different parts of this original system and the turbine  
36 controls represent the last stage. The original control equipment is no longer  
37 supported by the supplier, third-party suppliers have limited controls on hand, and  
38 the operator interface system being used is not compatible with this older control  
39 system. A PLC system is being designed and deployed. As part of this effort, we  
40 are replacing the present operator interface with a new platform that will allow  
41 expansion of systems in the future. This project will retain plant reliability while  
42 reducing the chances of an extended forced outage due to a DCS component failure.  
43 This project is expected to be completed in July of 2012 at a cost of \$571,000.  
44

1           **Replace Monitor Control Centers:** The present Monitor Control Centers are  
2 original equipment. They are still functioning, but we have been experiencing some  
3 problems that have used up spare parts. The original manufacturer no longer exists  
4 and compatible units that would allow for continued operation of this old gear is no  
5 longer available. This project will replace the obsolete equipment to maintain plant  
6 reliability. This project is expected to be completed in October of 2012 at a cost of  
7 \$256,000.  
8

9           **Truck Dumper Dust Containment Building:** Hog fuel trucks can create dust  
10 plumes during unloading. These plumes have been identified by local air authorities  
11 as a concern that will need to be addressed. Attempts to abate the dust by installing  
12 hoods and other deflection elements have improved the dust situation, but there are  
13 still concerns about the overall particulate emissions associated with this process.  
14 This project includes construction of a building around the unloading area to contain  
15 the particulates. This project is expected to be completed in November of 2013 at a  
16 cost of \$680,000.  
17

18           **Replace Grate Drive System:** The current grate drive system at Kettle Falls utilizes  
19 a hydraulically operated ratchet system to move the traveling grate. The ratcheting  
20 action causes the connecting links to wear out. This capital project will replace the  
21 hydraulic ratchet with a variable drive system to provide constant tension on the  
22 grate to prevent the cyclic wear on the grate system. This project is expected to be  
23 completed in July of 2013 at a cost of \$280,000.  
24

25           **Install New Water Supply System:** Kettle Falls receives its water from the City of  
26 Kettle Falls through an agreement that dates back to the construction of the plant in  
27 the early 1980's. That agreement expires in 2012 and future water rates will be  
28 higher. This effort is to secure necessary water rights and a long-term water supply  
29 for the plant that is controlled by the Company. A new well, sufficient to provide for  
30 plant needs, was developed in 2011. This capital work is for the installation of the  
31 water supply piping and distribution system to the existing Kettle Falls plant from  
32 the new well. The project involves installing nearly 1,000 feet of water supply line  
33 and distribution manifold at the plant. In 2011, water rights were acquired and  
34 submitted to the Washington Department of Ecology. The Department of Ecology  
35 is investigating those water rights to assure they are unencumbered. This ruling is  
36 expected to come in 2012 at which time those would be transferred to Avista. This  
37 project is expected to be completed in December 2012 at a total cost of \$1,180,000.  
38

39           **Purchase D10TQ Caterpillar Tractor:** This project involves the replacement of the  
40 D10 Fuel Handler at Kettle Falls Generating Station. The existing unit is from 1991  
41 and is in poor mechanical condition. These large bulldozers (fuel handlers) are  
42 essential to the operation of the plant. One day of lost production due to inability to  
43 load fuel costs \$13,337 in comparison to buying power on the open market. Fuel  
44 savings of \$35k/yr, and new machine would have much lower emissions. The  
45 existing unit should be replaced in December of 2012 at a cost of \$1,215,000.

1  
2 **Hydro – Little Falls Powerhouse Redevelopment Capital Projects – \$4,067,000**  
3 **(\$3,300,000 in 2012, \$767,000 in 2013)**  
4

5 **Replace 4kV Switchgear:** We have experienced several major failures of the  
6 generator breakers within the past five years. Attempts to recondition this old  
7 equipment have been unsuccessful and we still experience major failures. This has  
8 created a hazardous area for operations personnel when the equipment is energized.  
9 This work will replace all of the existing switchgear with new units, removing this  
10 concern and hazard. This project is expected to be completed in December of 2012,  
11 at a cost of \$1,600,000.  
12

13 **Replace Excitation System:** The existing excitation equipment is 60 years old. The  
14 amplidyne technology is no longer supported by the manufacturer and very few  
15 people in the country have the expertise to fix or maintain this system. In the mid-  
16 1980's, a Bailey digital controller was fitted to this equipment to keep these systems  
17 minimally operable. These systems have failed several times in the past four years  
18 causing major generator damage that has been repairable. This project is to replace  
19 the amplidyne and rotating exciter systems with new bus fed systems. This project is  
20 expected to be completed in December of 2012 at a cost of \$1,700,000.  
21

22 **Install Warehouse:** Over the next 10 to 12 years, major rehabilitation work is being  
23 planned for the Long Lake and the Little Falls plants (Little Falls is six miles from  
24 Long Lake). Storage space for major equipment, minor materials, and a construction  
25 staging area needs to be built to facilitate these projects. This warehouse will fill this  
26 need. Work includes erecting a new warehouse in the Long Lake operator's village  
27 and installation of the 30-ton gantry crane from the Little Falls powerhouse into this  
28 new warehouse. This project is expected to be completed in October 2013 at a cost  
29 of \$767,000.  
30

31 **Hydro – Post Falls Intake Gate Replacement Capital Project: \$4,600,000 in 2012**

32 Due to the deteriorated condition of the Post Falls HED intake gates and associated hoist  
33 mechanisms, Avista has committed to FERC to replace all six head gates and hoisting  
34 equipment by the end of 2012. This project will replace the existing wooden timbered head  
35 gates with new steel gates and to modify the structure to include a hoist system. Provisions  
36 for the gates will be made to pull the gates out for easy maintenance purposes. This work  
37 also includes installation of new controls and appropriate emergency power systems. This  
38 project is expected to be completed in December of 2012 at a cost of \$4,600,000.  
39

40 **Hydro – Nine Mile Redevelopment: \$2,800,000 in 2013**

41 This project is to replace Nine Mile Units #1 and #2 which are more than 100 years old and  
42 are worn out. Unit #1 has been shut down since 2005 due to mechanical failure and only the  
43 downstream pair of runners on Unit #2 are currently allowing the plant to run at less than  
44 half output. We are losing 6 MW of generation because of these issues. This is the third  
45 year of a multi-year project. Work planned includes purchase of spare runners for Units #3

1 and #4 to address failures of those units as well as options for Units #1 and #2. Because of  
2 the failure of Unit #3, the Company decided to order a spare set of runners to assure  
3 minimum loss of output in the event either Unit #3 fails again or we see a similar failure on  
4 Unit #4. The Nine Mile Redevelopment Project is expected to be completed in September  
5 of 2013 at a cost of \$2,800,000.

6  
7 **Hydro – Clark Fork River Implementation PM&E: \$7,336,000 (\$3,883,000 in 2012 and**  
8 **\$3,453,000 in 2013)**

9 The Clark Fork Implementation PM&E agreement capital expenditures include recreation  
10 site improvements, design and construction of fish passage, total dissolved gas abatement  
11 facilities, and acquisition of property rights for habitat restoration. We are currently  
12 pursuing the acquisition of two separate conservation easements to protect riparian habitat  
13 on the Bull River in Montana. Numerous ongoing recreation site improvements include the  
14 replacement of boat ramps, docks, and restrooms; upgrading electrical and septic systems;  
15 and trail development and improvements. Habitat enhancement projects include  
16 improvement and maintenance of existing wetlands on the Noxon Rapids reservoir, tributary  
17 habitat enhancements, such as culvert replacement, stream bed reconstruction and riparian  
18 re-vegetation and protection to improve passage, spawning and rearing for native salmonids.

19  
20 **Hydro – Spokane River Implementation PM&E: \$3,500,000 (\$3,260,000 in 2012 and**  
21 **\$240,000 in 2013)**

22 The Spokane River Project capital projects fulfill FERC's license requirements related to  
23 wetlands, water quality, recreation, and land use improvements that will lead to  
24 improvements located at Nine Mile, and Lake Spokane (the Long Lake Dam reservoir). The  
25 water quality improvements and wetland acquisition and/or enhancements are mandatory  
26 conditions included in the License as part of the Washington and Idaho 401 Water Quality  
27 Certifications, whereas the recreation and land use projects are FERC's License  
28 requirements. This year we will continue modeling a number of potential total dissolved gas  
29 remedies for Long Lake Dam, and monitoring low dissolved oxygen (DO) in the tailrace  
30 below the dam to determine if the aeration equipment we installed last year will sufficiently  
31 meet the State's water quality standards. We are also installing additional aeration  
32 equipment in the Long Lake Powerhouse to further improve DO in the tailrace. We  
33 completed the channel modifications at Upper Falls last fall, which were approved by the  
34 Washington Department of Ecology. We will work to complete the required Nine Mile and  
35 Lake Spokane recreation projects during this year's construction season.

36  
37 **Other Small Capital Projects: \$541,000 (\$294,000 in 2012 and \$240,000 in 2013)**  
38  
39

40



**V. HYDRO RELICENSING**

1  
2 **Q. Would you please provide an update on work being done under the**  
3 **existing FERC operating license for the Company's Clark Fork River generation**  
4 **projects?**

5 A. Yes. Avista received a new 45-year FERC operating license for its Cabinet  
6 Gorge and Noxon Rapids hydroelectric generating facilities on the Clark Fork River on  
7 March 1, 2001. The Company has continued to work with the 27 Clark Fork Settlement  
8 Agreement signatories to meet the goals, terms, and conditions of the Protection, Mitigation  
9 and Enhancement (PM&E) measures under the license. The implementation program, in  
10 coordination with the Management Committee which oversees the collaborative effort, has  
11 resulted in the protection of approximately 2,694 acres of bull trout, wetlands, uplands, and  
12 riparian habitat. More than 37 individual stream habitat restoration projects have occurred  
13 on 23 different tributaries within our project area. Avista has collected data on nearly  
14 15,000 individual bull trout within the project area. The upstream fish passage program,  
15 using electrofishing, trapping and hook-and-line capture efforts, has reestablished bull trout  
16 connectivity between Lake Pend Oreille and the Clark Fork River tributaries above Cabinet  
17 Gorge and Noxon Rapids Dams through the upstream transport of 350 adult bull trout, with  
18 over 160 of these radio tagged and their movements studied. Avista has worked with the  
19 U.S. Fish and Wildlife Service to develop and test two experimental fish passage facilities.  
20 Avista, in consultation with key state and federal agencies, is currently developing designs  
21 for both a permanent upstream adult fishway for Cabinet Gorge, Noxon Rapids. Design is  
22 completed on a permanent tributary trap for Graves Creek (an important bull trout spawning  
23 tributary) with constructions scheduled for 2012.

1           Recreation facility improvements have been made to over 23 sites along the  
2 reservoirs. Avista also owns and manages over 100 miles of shoreline that includes 3,500  
3 acres of property to meet FERC requirements to meet our natural resource goals while  
4 allowing for public use of these lands where appropriate.

5           Finally, tribal members continue to monitor known cultural and historic resources  
6 located within the project boundary to ensure that these sites are appropriately protected.

7           **Q.     Would you please provide an update on the current status of managing**  
8 **total dissolved gas issues at Cabinet Gorge dam?**

9           A.     Yes. How best to deal with total dissolved gas (TDG) levels occurring  
10 during spill periods at Cabinet Gorge Dam was unresolved when the current Clark Fork  
11 license was received. The license provided time to study the actual biological impacts of  
12 dissolved gas and to subsequently develop a dissolved gas mitigation plan. Stakeholders,  
13 through the Management Committee, ultimately concluded that dissolved gas levels should  
14 be mitigated, in accordance with federal and state laws. A plan to reduce dissolved gas  
15 levels was developed with all stakeholders, including the Idaho Department of  
16 Environmental Quality. The original plan called for the modification of two existing  
17 diversion tunnels, which could redirect stream flows exceeding turbine capacity away from  
18 the spillway.

19           The 2006 Preliminary Design Development Report for the Cabinet Gorge Bypass  
20 Tunnels Project indicated that the preferred tunnel configuration did not meet the  
21 performance, cost and schedule criteria established in the approved Gas Supersaturation  
22 Control Plan (GSCP). This led the Gas Supersaturation Subcommittee to determine that the  
23 Cabinet Gorge Bypass Tunnels Project was not a viable alternative to meet the GSCP. The

1 subcommittee then developed an addendum to the original GSCP to evaluate alternative  
2 approaches to the Tunnel Project.

3 In September 2009, the Management Committee agreed with the proposed  
4 addendum, which replaces the Tunnel Project with a series of smaller TDG reduction  
5 efforts, combined with mitigation efforts during the time design and construction of  
6 abatement solutions take place.

7 FERC approved the GSCP addendum in February 2010 and in April 2010 the Gas  
8 Supersaturation Subcommittee (a subcommittee of the MC) chose five TDG abatement  
9 alternatives for feasibility studies. Feasibility studies and design continue on two of the  
10 alternatives. Final design and initiation of construction of the spillway crest modification  
11 prototype is anticipated in 2012.

12 **Q. Would you please give a brief update on the status of the work being**  
13 **done under the new Spokane River Hydroelectric Project's license?**

14 A. Yes. The Company received a new 50-year license for the Spokane River  
15 Project on June 18, 2009. The License incorporated key agreements with the Department of  
16 Interior and other key parties in both Idaho and Washington. Implementation of the new  
17 license began immediately, with the development of over 40 work plans prepared, reviewed  
18 and approved, as required, by the Idaho Department of Environmental Quality, Washington  
19 Department of Ecology, the U.S. Department of Interior, and FERC. The work plans pertain  
20 not only to license requirements, but also to meeting requirements under Clean Water Act  
21 401 certifications by both Idaho and Washington and of other mandatory conditions issued  
22 by the U.S. Department of Interior.

1           In 2011, Avista continued implementing a water quality, fisheries, recreation,  
2 cultural, wetland, aquatic weed management, aesthetic, operational and related conditions  
3 (PM&E measures) across all five hydro developments. The majority of the PM&E  
4 measures are on-going in nature, however a number are one-time improvements, such as the  
5 Upper Falls aesthetic spill project located in downtown Spokane. Over 340 acres of wetland  
6 mitigation properties were acquired in 2011 on Upper Hangman Creek in Idaho for the  
7 Coeur d'Alene Tribe through the Coeur d'Alene Reservation Trust Resources Restoration  
8 Fund that Avista established in 2009. We will now begin developing restoration plans for  
9 the properties.

10           Last year, we also developed wetland mitigation plans for our property along the St.  
11 Joe River and will begin restoring the wetlands in 2012. In 2012 we are continuing work  
12 with the various local, state, and federal agencies to complete the required recreation  
13 projects in Idaho, and will develop up to ten boat-in-only campsites on Lake Spokane, as  
14 well as other numerous improvements at boat launches, overlooks and interpretive areas on  
15 Lake Spokane and Nine Mile. We are currently assessing potential wetland mitigation  
16 properties in the Lake Spokane and Nine Mile areas in order to fulfill the required  
17 conditions. In 2012, we will continue to implement approved work plans that have been  
18 approved by FERC.

19           A number of the approved work plans require the Company to conduct extensive  
20 studies to determine appropriate measures to mitigate resource impacts. The more  
21 significant studies and mitigation measures include those for total dissolved gas (TDG)  
22 downstream of Long Lake Dam, which we began modeling in 2011 and will continue in  
23 2012, and dissolved oxygen in the tailrace below Long Lake Dam and in Lake Spokane, the

1 reservoir created by the Long Lake Dam. Initial estimates for measures to address TDG  
2 range between \$7.0 and \$17.0 million, and between \$2.5 and \$8.0 million to address  
3 dissolved oxygen in Lake Spokane. These estimates will be further refined as the relevant  
4 evaluations and studies are completed.

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

6 A. Yes it does.