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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	CASE NO. AVU-E-15-05
OF AVISTA CORPORATION FOR THE	)	
AUTHORITY TO INCREASE ITS RATES	)	
AND CHARGES FOR ELECTRIC AND	)	
NATURAL GAS SERVICE TO ELECTRIC	)	DIRECT TESTIMONY
AND NATURAL GAS CUSTOMERS IN THE	)	OF
STATE OF IDAHO	)	SCOTT J. KINNEY
	)	

FOR AVISTA CORPORATION

(ELECTRIC ONLY)

I. INTRODUCTION

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

A. My name is Scott J. Kinney. 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 graduated from Gonzaga University in 1991 with a B.S. in Electrical Engineering and I am a licensed Professional Engineer in the State of Washington. I joined the Company in 1999 after spending eight years with the Bonneville Power Administration. I have held several different positions at Avista in the Transmission Department, beginning as a Senior Transmission Planning Engineer. In 2002, I moved to the System Operations Department as a Supervisor and Support Engineer. In 2004, I was appointed as the Chief Engineer, System Operations and as the Director of Transmission Operations in June 2008. I became the Director of Power Supply in January 2013, where my primary responsibilities involve management and oversight of short- and long-term planning and acquisition of power resources.

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, and future resource plans. As part of an overview of the Company's risk management policy, I will provide an update on the Company's hedging practices. I will address hydroelectric and thermal project upgrades, followed by an update on recent developments regarding hydro licensing.

Company witness Ms. Andrews incorporated Idaho's share of the capital additions (2015 through 2017) described in my testimony.

A table of contents for my testimony is as follows:

Q. Are you sponsoring any Exhibits?

A. Yes. I am sponsoring Exhibit 4, Schedules 1 through 3. Schedule 1 includes Avista's 2013 Electric Integrated Resource Plan and Appendices, and Schedule 2 provides the 2013 IRP forecast of the Company's load and resource positions from 2014 through 2033. Confidential Schedule 3C includes Avista's Energy Resources Risk Policy.

II. RESOURCE PLANNING AND POWER OPERATIONS

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

A. Yes. Avista's owned generating resource portfolio includes hydroelectric generation projects, base-load coal and base-load natural gas-fired thermal generation facilities, waste wood-fired generation, and natural gas-fired peaking generation. Avista-owned generation facilities have a total capability of 1,851 MW, which includes 58% hydroelectric and 42% thermal resources.

Illustration Nos. 1 and 2 below summarize the present net capability of Avista's hydroelectric and thermal generation resources:

Illustration No. 1: Avista-Owned Hydroelectric Generation

Project Name	River System	Nameplate Capacity (MW)	Maximum Capability (MW)	Expected Energy (aMW)
Monroe Street	Spokane	14.8	15.0	11.6
Post Falls	Spokane	14.8	18.0	10.0
Nine Mile	Spokane	26.0	17.5	12.5
Little Falls	Spokane	32.0	35.2	22.1
Long Lake	Spokane	81.6	89.0	53.4
Upper Falls	Spokane	10.0	10.2	7.5
Cabinet Gorge	Clark Fork	265.2	270.5	124.8
Noxon Rapids	Clark Fork	518.0	610.0	198.3
Total Hydroelectric		**962.4**	**1,065.4**	**440.2**

Illustration No. 2: Avista-Owned Thermal Generation

Project Name	Fuel Type	Start Date	Winter Maximum Capacity (MW)	Sumer Maximum Capacity (MW)	Nameplate Capacity (MW)
Colstrip 3 (15%)	Coal	1984	111.0	111.0	123.5
Colstrip 4 (15%)	Coal	1986	111.0	111.0	123.5
Rathdrum	Gas	1995	178.0	126.0	166.5
Northeast	Gas	1978	68.0	42.0	61.2
Boulder Park	Gas	2002	24.6	24.6	24.6
Coyote Springs 2	Gas	2003	312.0	251.0	290.0
Kettle Falls	Wood	1983	47.0	47.0	50.7
Kettle Falls CT	Gas	2002	11.0	8.0	7.5
Total			**862.6**	**720.6**	**847.5**

Q. Would you please provide a brief overview of Avista's major power supply contracts?

A. Yes. Avista's contracted-for generation resource portfolio consists of Mid-Columbia hydroelectric, PURPA, a tolling agreement for a natural gas-fired combined cycle generator, and a contract with a wind generation facility.

The Company currently has long-term contractual rights for resources owned and operated by the Public Utility Districts of Chelan, Douglas and Grant counties. Illustration No. 3 below provides details about the Mid-Columbia hydroelectric contracts. The Rocky Reach and Rock Island contracts with Chelan PUD expired in December 2014, but the Company signed a one year agreement for 4 percent of Chelan PUD’s Rocky Reach and Rock Island hydroelectric output in 2015. The Company was also recently awarded a 5 percent slice of Chelan PUD’s Rocky Reach and Rock Island hydro output for 2016 though 2020 through a competitive bidding process. Additional details are provided in witness Mr. Johnson’s testimony. Illustration No. 4 provides details about other contracts currently in place.

Avista also has a long-term power purchase agreement (PPA) in place through October 2026 entitling the Company to dispatch, purchase fuel for, and receive the power output from, the Lancaster combined-cycle combustion turbine project located in Rathdrum, Idaho. In 2011, the Company executed a 30-year power purchase agreement to purchase the output (105 MW peak) and all environmental attributes from the Palouse Wind, LLC wind generation project that began commercial operation in December 2012. The Company's contract with the Stateline Wind facility terminated in March 2014, and the contract to sell energy and associated environmental attributes with the Sacramento Municipal Utility District ended in December 2014.

Illustration No. 3: Mid-Columbia Hydroelectric Capacity and Energy Contracts[1]

Counter Party – Hydroelectric Project	Share (%)	Start Date	End Date	Estimated On-Peak Capability (MW)	Annual Energy (aMW)
Grant PUD – Priest Rapids	3.7	12/2001	12/2052	28.2	16.7
Grant PUD – Wanapum	3.7	12/2001	12/2052	31.0	17.9
Chelan PUD – Rocky Reach	4.0	1/2015	12/2015	46.5	14.7
Chelan PUD – Rock Island	4.0	1/2015	12/2015	16.1	20.5
Douglas PUD - Wells	3.3	2/1965	8/2018	27.9	14.7
Canadian Entitlement[1]				**-8.1**	**-4.6**
2015 Total Net Contracted Capacity and Energy				**141.6**	**79.9**

[1] Under the Columbia River Treaty signed in 1961 and the Pacific Northwest Coordination Agreement (PNCA) signed in 1964, Canada receives return energy (Canadian Entitlement) related to storage water in upstream reservoirs for coordinated flood control and power generation optimization.

Illustration No. 4: Other Contractual Rights and Obligations Through 2015

Contract	Type	Fuel Source	End Date	Winter Capacity (MW)	Summer Capacity (MW)	Annual Energy (aMW)
Energy America, LLC *	Sale	Various	12/2019	-35	-50	-42.5
PGE Capacity Exchange	Exchange	System	12/2016	-150	-150	0
Douglas Settlement	Purchase	Hydro	9/2018	2	2	3
WNP-3	Purchase	System	6/2019	82	0	42
Lancaster	Purchase	Gas	10/2026	290	249	222
Palouse Wind	Purchase	Wind	12/2042	0	0	40
Nichols Pumping	Sale	System	10/2018	-6.8	-6.8	-6.8
PURPA Contracts	Purchase	Varies	Varies	47.6	47.6	28.8
Total				**229.8**	**91.8**	**286.5**

*Energy America contracts start July 1, 2015 and includes 42.5 aMW energy plus REC's, 2016-2018 includes 50 aMW energy plus REC's and 2019 includes 20 aMW energy plus REC's.

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

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

Q. Please summarize Avista's load and resource position.

A. Avista's 2013 IRP shows forecasted annual energy deficits beginning in 2026, and sustained annual capacity deficits beginning in 2020.[2] These capacity and energy load/resource positions are shown on pages 2-39 through 2-41 of Schedule 1. Schedule 2 shows the 2013 IRP load and resource projection. Avista's IRP projection shows an annual energy deficit beginning in 2026 of about 19 aMW, and increasing to a 284 aMW deficit in 2033. The Company's January capacity resource position, based on an 18-hour peak event (6 hours per day and over 3 days), is projected to be surplus through 2019. Sustained annual capacity deficiencies, based on a January peak, begin at 42 MW in 2020 and increase to a 551 MW deficit in 2033. The Company's August capacity resource position, based on an 18-hour peak event, is projected to be surplus through 2023. Sustained annual capacity deficiencies, based on an

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[2] The Company has a 150 MW capacity exchange agreement with Portland General Electric that ends in December 2016 and Avista has short-term annual capacity deficits in 2015 and 2016. Sustained annual capacity deficits begin in 2020.

August peak, begin at 2 MW in 2024 and increase to a 361 MW deficit in 2033.

The Company's updated load and resource position will be included with the submission of the 2015 Electric IRP in August 2015.

Q. How does Avista plan to meet future energy and capacity needs?

A. The Company is currently guided by the 2013 Preferred Resource Strategy (PRS). The current PRS is described in the 2013 Electric IRP, which is attached as Schedule 1 of Exhibit No. 4. The IRP provides details about future resource needs, specific resource costs, resource-operating characteristics, and the scenarios used for evaluating the mix of resources for the PRS. The Commission acknowledged the 2013 Electric IRP in Case No. AVU-E-13-07 on March 20, 2014 in Order No. 32997. The IRP represents the preferred plan at a point in time; however, Avista continues evaluating resource options to meet future load requirements and is currently working on its next IRP, which will be filed in August 2015. The Company has held five of six scheduled TAC meetings and is currently finalizing the PRS and completing scenario analysis.

Avista's 2013 PRS includes less than one MW of distribution efficiencies, 221 MWs of cumulative energy efficiency, 19 MWs of demand response, 6 MWs of upgrades to existing thermal plants, and 569 MWs of natural gas-fired plants (299 MWs of simple cycle combustion turbines (SCCT) and 270 MWs of combined-cycle combustion turbine (CCCT)). The timing and type of these resources as published in the 2013 IRP is provided in Illustration No. 5. The Company's draft 2015 PRS does not deviate significantly from the 2013 PRS.

Illustration No. 5: 2013 Electric IRP Preferred Resource Strategy

Resource Type	By the End of Year	Nameplate (MW)	Energy (aMW)
SCCT	2019	83	76
SCCT	2023	83	76
CCCT	2026	270	248
SCCT	2027	83	76
Rathdrum CT Upgrade	2028	6	5
SCCT	2032	50	46
Total		575	529
Efficiency Improvements	**By the End of Year**	**Peak Reduction (MW)**	**Energy (aMW)**
Energy Efficiency	2014-2033	221	164
Demand Response	2022-2027	19	0
Distribution Efficiencies	2014-2017	<1	<1
Total Efficiency		240	164

Q. Would you please provide a high-level summary of Avista's risk management program for energy resources?

A. Yes. Avista Utilities uses several techniques to manage the risks associated with serving load and managing Company-owned and controlled resources. The

Energy Resources Risk Policy, which is attached as Confidential Schedule 3C of Exhibit No. 4, provides general guidance to manage the Company's energy risk exposure relating to electric power and natural gas resources over the long-term (more than 41 months), the short-term (monthly and quarterly periods up to approximately 41 months), and the immediate term (present month).

The Energy Resources Risk Policy is not a specific procurement plan for buying or selling power or natural gas at any particular time, but is a guideline used by management when making procurement decisions for electric power and natural gas fuel for generation. The policy considers several factors, including the variability associated with loads, hydroelectric generation, planned outages, and electric power and natural gas prices in the decision-making process.

Avista aims to develop or acquire long-term energy resources based on the IRP's PRS, while taking advantage of competitive opportunities to satisfy electric resource supply needs in the long-term period. Electric power and natural gas fuel transactions in the immediate term are driven by a combination of factors that incorporate both economics and operations, including near-term market conditions (price and liquidity), generation economics, project license requirements, load and generation variability, reliability considerations, and other near-term operational factors.

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

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

III. GENERATION CAPITAL PROJECTS

Q. Would you please provide a brief description of the generation-related capital projects planned for 2015, 2016 and 2017?

A. Yes. As shown in Table No. 1 below, the total 2015, 2016 and 2017 generation capital projects to be completed total $122.9 million, $45.5 million, and $83.7 million, respectively, on a system basis. Details about the generation-related capital projects totaling $252.2 million are discussed below.

TABLE NO. 1 Generation / Production Capital Projects (System)			
Business Case Name	2015 $ (000's)	2016 $ (000's)	2017 $ (000's)
Hydro - Base Load Hydro	$ 1,974	$ 1,149	$ 1,149
Hydro - Clark Fork Settlement Agreement	13,988	6,054	22,836
Hydro - Generation Battery Replacement	434	250	250
Hydro - Hydro Safety Minor Blanket	151	75	80
Hydro - Little Falls Plant Upgrade	14,300	9,000	10,000
Hydro - Nine Mile Rehab	56,567	9,871	858
Hydro - Regulating Hydro	5,186	3,533	3,533
Hydro - Spokane River License Implementation	1,266	397	17,018
Other - Base Load Thermal Plant	2,200	2,200	2,201
Other - Peaking Generation	501	500	500
Thermal - Kettle Falls Water Supply	1,529	-	-
Thermal - Colstrip Thermal Capital	2,497	10,480	9,617
Other - Coyote Springs LTSA	-	2,000	730
Hydro - Noxon Spare Coils	1,350	-	-
Hydro - Post Falls South Channel Replacement	9,309	-	-
Hydro - Cabinet Gorge Unit 1 Refurbishment	11,687	-	-
Cabinet Gorge Automation Replacement	-	-	2,842
Kettle Falls Stator Rewind	-	-	7,930
Long Lake Replace Field Windings	-	-	4,172
	$ 122,939	**$ 45,509**	**$ 83,716**

Base Load Hydro: 2015: $1,974,000; 2016: $1,149,000; 2017: $1,149,000

This program covers the capital maintenance expenditures required to keep Avista's Upper Spokane River hydroelectric plants operating within 90% of their current performance, assuming some degradation of performance over time. The plants covered in this program include Post Falls, Upper Falls, Monroe Street, and Nine Mile. The program focuses on ways to maintain compliance and reduce overall operations and maintenance expenses while maintaining a reasonable unit availability through a programmatic approach, rather than reacting to problems as they develop. The historical availability for the base load hydro plants has been declining over the past decade due to deteriorating equipment and a need to replace some equipment and systems that are as much as 100 years old.

Clark Fork Settlement Agreement – 2015: $13,988,000; 2016: $6,054,000; 2017: $22,836,000

These capital costs are required for the facilitation of the Clark Fork Protection, Mitigation and Enhancement (PM&E) measures. The implementation of programs is done through the License issued to Avista Corporation for a period of 45 years, effective March 1, 2001, to operate and maintain the Clark Fork Project No. 2058. The License includes hundreds of specific legal requirements, many of which are reflected in License Articles 404-430. These Articles derived from a comprehensive settlement agreement between Avista and 27 other parties, including the States of Idaho and Montana, various federal agencies, five Native American tribes, and numerous Non Governmental Organizations. Avista is required to develop, in consultation with the Management Committee, a yearly work plan and report, addressing all PM&E measures of the License. In addition, implementation of these measures is intended to address ongoing compliance with Montana and Idaho Clean Water Act requirements, the Endangered Species Act (fish passage), and state, federal and tribal water quality standards as applicable. License articles also describe our operational requirements for items such as minimum flows, ramping rates and reservoir levels, as well as dam safety and public safety requirements.

Generation Battery Replacement – 2015: $434,000; 2016: $250,000; 2017: $250,000

This program is based on an asset management plan for the station batteries in all generating stations. This item will also have some minor fluctuations as the number and size of batteries in any particular year can change.

Hydro Safety Minor Blanket – 2015: $151,000; 2016: $75,000; 2017: $80,000

This item funds periodic capital purchases and projects to ensure public safety at hydro facilities, on and off water, in the context of FERC regulatory and license requirements.

Little Falls Plant Upgrade– 2015: $14,300,000; 2016: $9,000,000; 2017: $10,000,000

The existing Little Falls equipment ranges in age from 60 to more than 100 years old. Forced outages at Little Falls because of equipment failures have significantly increased over the past six years, from about 20 hours in 2004 to several hundred hours in the past three to four years. This project will replace nearly all of the older, unreliable equipment with new equipment. This project includes replacing two of the turbines, all four generators, all generator breakers, three of the four governors, all of the automatic voltage regulators, removing all four generator exciters, replacing the unit controls, changing the switchyard configuration, replacing the unit protection system, and replacing and modernizing the station service.

Nine Mile Rehabilitation – 2015: $56,567,000; 2016: $9,871,000; 2017: $858,000

This capital program is necessary to rehabilitate and modernize the four unit Nine Mile HED. The program includes projects to replace the existing 3 MW Units 1 and 2, which are more than 100 years old and worn out, with two new 8 MW generators/turbines. The new units will add 1.4 aMW of energy beyond the original configuration and 6.4 MW of capacity above current generation levels.[3] In addition to these capacity upgrades, the Nine Mile facility will receive upgrades to the following:

- hydraulic governors;
- static excitation system;
- switchgear;
- station service;
- control and protection packages;
- ventilation upgrades;
- rehabilitation of intake gates and sediment bypass system;
- a new warehouse will be constructed;
- new tail race gate system will be added;
- new grounding and communications will be added;
- a barge landing will be added;
- a cottage will be removed and another remodeled;
- a new panel room will be added;
- Units 3 and 4 will be overhauled and modernized;
- the powerhouse will be restored;
- new access gates and controls will be added; and

[3] The additional output above the current generation has been included in the AURORAXMP power cost model reflecting the benefit of this project.

- other improvements will be made.

Regulating Hydro – 2015: $5,186,000; 2016: $3,533,000; 2017: $3,533,000

This program covers the capital maintenance expenditures required to keep the Long Lake, Little Falls, Noxon Rapids and Cabinet Gorge plants operating at their current performance levels. The program will work to improve the reliability of these plants so that their value can be maximized in both the energy and ancillary markets.

Spokane River Implementation PM&E – 2015: $1,266,000; 2016: $397,000; 2017: $17,018,000

This category covers the implementation of Protection, Mitigation and Enhancement (PM&E) programs related to the FERC License for the Spokane River. This includes items enforceable by FERC, mandatory conditioning agencies, and through settlement agreements. Additional details concerning the PM&E measures for the Spokane River license are included in the hydro relicensing section that follows.

Base Load Thermal Plant – 2015: $2,200,000; 2016: $2,200,000; 2017: $2,201,000

This program is necessary to sustain or improve the existing operating costs of base load thermal generating stations, including Coyote Springs 2, Colstrip, Kettle Falls, and Lancaster. Capital projects include replacement of items identified through asset management decisions and programs necessary to maintain reliable and low operating costs of these plants. As this program proceeds, it is expected that forced outage rates and forced deratings of these facilities will decrease to a level one standard deviation less than the current average, resulting in more economic benefits of the project.

Peaking Generation – 2015: $501,000; 2016: $500,000; 2017: $500,000

This program covers the capital maintenance expenditures required to keep the natural gas-fired peaking units (Boulder Park, Rathdrum CT, and Northeast CT) operating at or above their current performance levels. The program focuses on maximizing the ability of these units to start and run when demanded (starting reliability).

Kettle Falls Water Supply– 2015: $1,529,000

The Kettle Falls Generation Plant receives its water from the City of Kettle Falls from an agreement that dates back to the construction of the plant in the early 1980s. This effort is to secure necessary water rights and a long term water supply for the plant that is controlled by the company.

Colstrip Thermal Capital – 2015: $2,497,000; 2016: $10,480,000; 2017: $9,617,000

This program includes ongoing capital expenditures associated with normal outage activities on Units 3 & 4 at Colstrip. Every two out of three years, there are planned outages at Colstrip with higher capital program activities. For non-outage years, the program activities are reduced. Avista votes its 15 percent share of Units 3 & 4 and its approximate 10 percent share of common facilities to approve or disapprove of the budget proposed by Pacific Pennsylvania Light Montana (PPLM) on behalf of all the owners.

Coyote Springs 2 LTSA Capital Addition – 2016: $2,000,000; 2017: $730,000

This program covers the capital accruals required to execute our Long Term Service Agreement (LTSA) with General Electric for Coyote Springs Unit 2. This program will have fluctuations to account for the variable operating hours and operating conditions that feed into the LTSA formula.

Noxon Spare Coils – 2015: $1,350,000

This project is to replace the spare coils that were used in the Spring of 2013 to repair the stator winding that failed for Unit 4. This item will procure 100 spare coils. These spares cover Units 1 through 4 (Unit 5 uses different coils). Because Avista had spares available, Unit 4 was able to return to normal service within 11 weeks. Without these spares, the unit would have been out for nine months or more. Prices for coils supplied under emergency conditions would likely carry a 30 percent cost premium. This project does not include any installation, only the replacement of previously held stock.

Post Falls South Channel Gate Replacement – 2015: $9,309,000

Avista is in the process of refurbishing the south channel gates to comply with FERC Dam Safety directives. The project entails removing most of the existing concrete structure and replacing it with a new concrete structure, new spillway gates, and new hoist systems to automate gate operation.

Cabinet Gorge Unit 1 Refurbishment – 2015: $11,687,000
This is the capital portion of a major overhaul project planned for Cabinet Gorge Unit #1. The runner hub has significant mechanical issues and needs to be replaced to allow for frequent cycling for load following. The present automatic voltage regulator provides a relatively slow response due to its hybrid design and has no limiters for generator protection. A new system will provide faster response and add limiters. The machine monitoring is to allow for better analysis of machine condition for this important unit. Rehabilitation of this unit will also allow flexibility around minimum flow for fish habitat.

Cabinet Gorge Automation Replacement – 2017: $2,842,000
This project is to replace the unit and station service control equipment at Cabinet Gorge with a system compatible with Avista's current standards. The Bailey Net 90 equipment that is installed currently is obsolete because replacement of the system can only be done through secondary and salvage markets. In addition, the current system does not provide enough inputs and outputs that allow implementation of standard unit control and monitoring schemes. This work will replace the existing panel and control systems with a new system. The scope of work has expanded to include replacement governors, voltage regulators, and protective relays.

Kettle Falls Stator Rewind – 2017: $7,930,000
The Kettle Falls generator is over 32 years old and is at the end of its expected life. This project consists of monitoring the existing machine, developing rewind contract, manufacturing replacement coils, disassembly, coil removal, new coil installation, reassembly, startup, testing and commissioning. Consequences of failure include an unscheduled outage with lost generation, loss of renewable energy credits, long term interruption of fuel supply, collateral damage to core and hydrogen cooling with resulting safety hazards.

Long Lake Replace Field Windings – 2017: $4,172,000
Over the past 10 years, the Company has observed a continuing decline in the insulation level on the

generators at Long Lake as measured using Megger test instruments. Long Lake has experienced an increasing amount of forced outages and down time due to the deteriorating condition of these units.

IV. HYDRO RELICENSING

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

A. Yes. Avista received a new 45-year FERC operating license for its Cabinet Gorge and Noxon Rapids hydroelectric generating facilities on the Clark Fork River on March 1, 2001. The Company has continued to work with the 27 Clark Fork Settlement Agreement signatories to meet the goals, terms, and conditions of the Protection, Mitigation and Enhancement (PM&E) measures under the license. The implementation program, in coordination with the Management Committee which oversees the collaborative effort, has resulted in the protection of approximately 80,000 acres of bull trout, wetlands, uplands, and riparian habitat. More than 37 individual stream habitat restoration projects have occurred on 23 different tributaries within our project area. Avista has collected data on almost 19,000 individual bull trout within the project area. The upstream fish passage program, using electrofishing, trapping and hook-and-line capture efforts, has reestablished bull trout connectivity between Lake Pend Oreille and the Clark Fork River tributaries above Cabinet Gorge and Noxon Rapids Dams through the upstream transport of 498 adult bull trout, with over 160 of these radio tagged and their movements studied. Avista has worked with the U.S. Fish and Wildlife Service to develop and test two experimental fish passage facilities. Avista, in consultation with certain state and federal agencies, is currently developing designs for a permanent upstream adult fishway for Cabinet Gorge and Noxon Rapids. In 2013, designs for the Cabinet Gorge Fishway Fish Handling and Holding Facility were completed and construction began in 2013. A permanent tributary trap on Graves Creek (an important bull trout spawning tributary) was constructed in 2012 and testing began 2013. A three-year evaluation process is ongoing to determine if future permanent tributary traps are warranted.

Recreation facility improvements have been made to over 28 sites along the reservoirs. Avista also owns and manages over 100 miles of shoreline that includes 3,500 acres of property to meet FERC required natural resource goals, while allowing for public use of these lands where appropriate.

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

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

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

The 2006 Preliminary Design Development Report for the Cabinet Gorge Bypass Tunnels Project indicated that the preferred tunnel configuration did not meet the performance, cost and schedule criteria established in the approved Gas Supersaturation Control Plan (GSCP). This led the Gas Supersaturation Subcommittee to determine that the Cabinet Gorge Bypass Tunnels Project was not a viable alternative to meet the GSCP. The subcommittee then developed an addendum to the original GSCP to evaluate alternative approaches to the Tunnel Project.

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

FERC approved the GSCP addendum in February 2010 and in April 2010 the Gas Supersaturation Subcommittee (a subcommittee of the MC) chose five TDG abatement alternatives for feasibility studies. Feasibility studies and preliminary design were completed on two of the alternatives in 2012. Final design, construction, and testing of the spillway crest modification prototype was completed in 2013. Test results indicated over all TDG performance was positive, however, additional modifications were required to address cavitation issues. Modification of the spillway crest prototype and retesting were completed in 2014. It is anticipated that up to seven additional spillway crests will be modified by 2018.

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

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

Since 2011, Avista has implemented water quality, fisheries, recreation, cultural, erosion, wetland, aquatic weed management, aesthetic, operational and related conditions across all five hydro developments under the Protection Mitigation and Enhancement (PM&E) measures. The majority of the PM&E measures are on-going in nature, however, a number are one-time improvements, such as the Upper Falls aesthetic spill project located in downtown Spokane. Six hundred and fifty six acres of wetland mitigation properties were acquired in 2011 and 2012 on Upper Hangman Creek in Idaho for the Coeur d'Alene Tribe through the Coeur d'Alene Reservation Trust Resources Restoration Fund that Avista established in 2009. The Company developed wetland restoration plans for approximately 500 of the required 1,368 replacement acres of wetland and riparian habitat and is waiting for approval by the U.S. Department of Interior, Bureau of Indian Affairs to continue implementing the plans. The U.S. Department of Interior, Bureau of Indian Affairs and FERC approved revisions, requested by the Coeur d'Alene Tribe, to the Coeur d'Alene Reservation Erosion Control Implementation Plan. The revisions allow Avista and the Tribe to acquire, restore, manage, and monitor 56 acres of land consistent with the requirements of the Wetland and Riparian Habitat Plan, mentioned above, in lieu of implementing shoreline stabilization along 63,130 feet of the Lower St. Joe River. The new total for all replacement lands is now 1,424 acres. In 2014, the Company monitored the vegetation on the recently completed 124-acre wetland mitigation project along the St. Joe River and will be responsible for maintaining approximately half of it, which lies on Avista's property, for the License term.

Avista continued work with the various local, state, and federal agencies to complete more of the required recreation projects in Idaho, such as trail and interpretive sign improvements in Post Falls, and public recreation improvements along the St. Maries River. In Washington, the Company completed the ten boat-in-only campsites on Lake Spokane, and a new carry-in-only boat launch at Nine Mile Falls. The Company developed and is implementing the management plan for the recently purchased 109 acre Sacheen Springs Wetland Complex located along the Little Spokane River. In 2015, Avista will continue to develop and implement local, state, and federally required work plans to fulfill License conditions.

A number of the approved work plans required the Company to conduct extensive studies to determine appropriate measures to mitigate resource impacts. The more significant studies and mitigation measures include those for total dissolved gas (TDG) downstream of Long

Lake Dam. Avista modeled several different types of spillway modifications between 2011 and 2013 and completed the design for the desired deflector configurations in 2014. Following the design, Avista requested a one-year setback in the construction schedule to allow completing of the construction process in 2016-2017 instead of 2015-2016. The new schedule will allow the Company to complete work on the dam's spillway gate seals and the rigorous permitting processes prior to constructing the new deflectors. The Company completed the proposed dissolved oxygen (DO) measure in the tailrace below Long Lake Dam and is continuing to monitor its effectiveness in addressing low DO in the river below the dam. Avista is also continuing to evaluate potential measures to improve DO in Lake Spokane, the reservoir created by the Long Lake Dam. Cost estimates to construct the TDG spillway deflectors range between $8.0 and $10.0 million, and between $2.5 and $8.0 million to address DO in Lake Spokane. These estimates will be refined as the evaluations and studies are completed.

Q. Please explain the costs incurred by the Company to study the total dissolved gas downstream of Long Lake Dam, and the Company's proposal for recovering these costs.

A. Through December 31, 2012, the Company had incurred $1.340 million of system costs related to meeting certain regulatory requirements to improve the dissolved oxygen levels in Lake Spokane, as described above. Idaho’s share of these costs was approximately $473,000. As described by Ms. Andrews, through this general rate case filing, the Company is seeking a prudence finding related to these costs, and amortization of the TDG costs for Lake Spokane over a two-year period beginning in 2016[4].

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

A. Yes it does.

[4] As explained by Ms. Andrews, the Company was authorized in Case No. AVU-E-13-06 (see Order No. 32917) to defer these costs in FERC Account 182.3 without a carrying charge, with a prudency review to occur in the Company’s next general rate case or other proceeding.