Exhibit No.__(SJK-1T)

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-14____________

DIRECT TESTIMONY OF

SCOTT J. KINNEY

REPRESENTING AVISTA CORPORATION

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 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. The information included within my testimony, related to increased costs associated with hydroelectric and thermal project upgrades, is provided for informational purposes only. As explained by Company witness Ms. Andrews, the Company is basing its electric revenue increase requested in this case based on its electric Attrition Studies. However, as a "cross check" to the Company's request based on the electric Attrition Study, Ms. Andrews has also prepared an electric Pro Forma Cross Check Study, which incorporate Washington's share of the capital additions described further in my testimony.[1]

A table of contents for my testimony is as follows:

Q. Are you sponsoring any exhibits?

A. Yes. Exhibit No.___(SJK-2) includes Avista's 2013 Electric Integrated Resource Plan and Appendices, Exhibit No.___(SJK-3) provides a forecast of the Company's load and resource positions from 2014 through 2033. Confidential Exhibit No.___(SJK-4C) includes Avista's Energy Resources Risk Policy.

[1] However, as noted later in my testimony at Section IV. Hydro Relicensing, the Company is seeking a prudence finding of the costs related to the improvement of dissolved oxygen levels in Lake Spokane, and amortization of these costs over a three-year period beginning in 2015. As discussed by Company witness Ms. Andrews, since the amortization of these costs start in 2015, they represent activity which was not included in the June 2013 normalized commission basis results used as the starting point of the Company's Attrition Study analysis. Ms. Andrews, therefore, includes the Lake Spokane three-year amortization as an "After Attrition Adjustment" in both her Attrition and Pro Forma Cross Check Studies in determination of the Company's final revenue requirement requested in this case.

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 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 summarize present net capability of Avista's hydroelectric and thermal owned-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 generation contracts?

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

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 provides details about the Mid-Columbia hydroelectric contracts. The current Rocky Reach and Rock Island contracts with Chelan PUD end in December 2014, but the Company will pursue new contracts with these plants through the auction process described in witness Mr. Johnson's testimony. Illustration No. 4 provides details about other contracts. Avista also has a long-term power purchase agreement (PPA) in place through 2026 entitling the Company to dispatch, purchase fuel for and receive the power output from the 275 MW Lancaster combined-cycle combustion turbine project located in Rathdrum, Idaho. In 2011, the Company executed a 20-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.

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

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	3.0	7/2011	12/2014	34.5	21.0
Chelan PUD – Rock Island	3.0	7/2011	12/2014	13.9	10.7
Douglas PUD - Wells	3.3	2/1965	8/2018	27.9	14.7
Canadian Entitlement				**-8.1**	**-4.6**
2014 Total Net Contracted Capacity and Energy				**127.4**	**76.4**
2015 Total Net Contracted Capacity and Energy				**81.9**	**46.3**

Illustration No. 4: Other Contractual Rights and Obligations

Contract	Type	Fuel Source	End Date	Winter Capacity (MW)	Summer Capacity (MW)	Annual Energy (aMW)
Stateline	Purchase	Wind	3/2014	0	0	9
Sacramento Municipal Utility District	Sale	System	12/2014	-50	-50	-50
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	50.5	50.5	30.5
Total				**217.7**	**94.7**	**289.7**

Q. Has the interconnection with the Lancaster Substation been completed?

A. Yes. Avista entered into a process with the Bonneville Power Administration (BPA) through a Line and Load Interconnection request on September 2, 2009, to perform a joint study concerning the interconnection of Avista's 230 kV transmission lines to the BPA Lancaster Substation. The BPA completed its Line and Load Interconnection System Impact Study on August 20, 2010 and completed its Line and Load Interconnection Facilities Study on November 8, 2011. An environmental impact study was performed and a construction agreement was entered into with the BPA. The interconnection between Avista's 230 kV line and the Lancaster Substation was completed on December 13, 2013. Avista gave the required two-year notice to the BPA to terminate 150 MW of transmission service on August 31, 2012. The BPA accepted the request to terminate the 150 MW of transmission service effective August 31, 2014. Please refer to witness Ms. Rosentrater for additional details about this interconnection.

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 current 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 Exhibit No.___(SJK-2). Exhibit No.___(SJK-3) shows our most recent 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 August peak, begin at 2 MW in 2024 and increase to a 361 MW deficit in 2033.

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

A. The Company will be guided by the 2013 Preferred Resource Strategy (PRS). The current PRS is described in the 2013 Electric IRP, which is attached as Exhibit No.___(SJK-2). 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 Company's 2013 Electric IRP was submitted to the Commission

[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.

on August 30, 2013, following the completion of a public process involving six Technical Advisory Committee meetings from May 23, 2012 through June 19, 2013. The Commission is reviewing the 2013 Electric IRP in Docket No. UE-121421. The IRP represents the preferred plan at a point in time; however, Avista continues evaluating different resource options to meet future load requirements and will file its next IRP in August 2015.

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.

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 Exhibit No.___(SJK-4C), 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, and electric power and natural gas prices in the decision-making process regarding procurement of electric power and natural gas for generation.

Avista aims to develop or acquire long-term energy resources based on the Integrated Resource Plan's Preferred Resource Strategy, 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.

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

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

Avista plans to meet its RPS obligations with qualified hydroelectric upgrades, purchased RECs, wind generation, and qualifying biomass generation starting in 2016. Illustration No. 6 shows Avista's projected net REC position from 2014 through 2020 before applying the rollover provision. RECs associated with the Palouse Wind project include the apprenticeship credit. The Washington State Apprenticeship and Training Council approved the apprenticeship credit certification on October 23, 2013. The sale of excess RECs is addressed in witness Mr. Johnson's testimony.

Illustration No. 6: Washington Renewable Portfolio Standard Requirements (aMW)

Year	Percentage of Washington Load	Total Projected Need	REC Position in Excess of Need
2014	3%	18.9	47.9
2015	3%	19.1	53.6
2016	9%	57.9	45.3
2017	9%	58.3	44.4
2018	9%	58.9	43.7
2019	9%	59.5	43.7
2020	15%	100.0	3.1

III. GENERATION CAPITAL PROJECTS

Q. Would you please provide a brief description of the generation-related capital projects that occurred in the last half of 2013 and are planned for in 2014 and 2015?

A. Yes. As shown in Illustration No. 7, the total 2013, 2014 and 2015 generation capital projects to be completed, as discussed by Mr. DeFelice, total $15.216 million, $52.641 million and $98.677 million, respectively on a system basis. Details about the 26 generation capital projects totaling $167 million are discussed below.

Illustration No. 7: 2013 – 2015 Generation Capital Projects Summary

$ (000's)			
Generation / Production (System):	**Jul-Dec 2013**	**2014**	**2015**
Hydro - Base Load Hydro	$ 903	$ 1,000	$ 1,000
Hydro - Clark Fork Settlement Agreement	1,719	10,830	7,081
Hydro - Generation Battery Replacement	112	100	183
Hydro - Hydro Safety Minor Blanket	50	65	70
Hydro - Little Falls Plant Upgrade	27	9,000	6,500
Hydro - Nine Mile Rehab	990	9,208	47,044
Hydro - Regulating Hydro	3,292	2,500	3,000
Hydro - Spokane River License Implementation	1,860	4,815	462
Thermal - Base Load Thermal Plant	4,135	2,200	2,200
Thermal - Peaking Generation	1,000	500	500
Hydro - Post Falls Intake Gate	1	-	-
Other - Coyote Springs LTSA	179	-	-
Other - Rathdrum CT Upgrade Unit	45	-	-
Hydro - Long Lake Replace Field Windings	-	800	2,430
Hydro - Noxon Spare Coils	-	1,350	-
Other - CS2 Inlet Air Sys	-	500	-
Thermal - Colstrip Thermal Capital	-	8,004	3,177
Thermal - Kettle Falls Water Supply	-	1,615	
Hydro - Post Falls South Channel Replacement	-	-	11,008
Hydro - Cabinet Gorge Unit 1 Refurbishment	-	-	11,400
Thermal - KFGS Ash Collector	-	-	1,907
	$ 14,312	**$ 52,488**	**$ 97,962**

Base Load Hydro: $2,903,000 ($903,000 in 2013, $1,000,000 in 2014 and $1,000,000 in 2015)

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 about 100 years old. There is also $1,075,000 in projected capital costs for 2016.

Base Load Thermal Plant: $8,535,000 ($4,135,000 in 2013, $2,200,000 in 2014 and $2,200,000 in 2015)

This program is necessary to sustain or improve the existing operating costs of base load thermal generating stations, including Coyote Springs 2, Colstrip, and Kettle Falls. 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 derates of these facilities will decrease to a level one standard deviation less than the current average resulting in more economic benefits of the project. There is also $2,205,000 in projected capital costs in 2016.

Cabinet Gorge HED Unit #1 Refurbishment: $11,400,000 (All in 2015)

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 associated with the integration of intermittent renewable resources. 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 critical unit. New protective relays will be installed and new controls will be integrated with the project to replace the failing Bailey NET90 system. Rehabilitation of this unit will also allow flexibility around minimum flow for fish habitat.

Colstrip Capital Additions: $11,595,168 ($0 in 2013, $8,004,285 in 2014 and $3,176,850 in 2015)

This program includes ongoing capital expenditures associated with normal outage activities on Units 3 & 4 at Colstrip. Every 2 out of 3 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% share of Unit's 3 & 4 and its approximate 10% share of common facilities to approve or disapprove of the budget proposed by PPLM on behalf of all the owners. Individual projects are reviewed for appropriate rates of return and necessity. There is also $5,836,350 in projected capital costs in 2016.

Coyote Springs 2 LTSA Cash Accrual: $179,000 (All in 2013)
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.

Coyote Springs 2 Inlet Air System $500,000 (All in 2014)
This project replaces the present air filters with a new system that is more effective at particulate removal than the current system. Cursory studies indicate that these new filters would reduce the number of water washes required to maintain unrestricted airflow, and reduce the particles going through the turbine, which in turn reduces erosion on the blades and buckets. O&M savings of $20,587 are estimated for 2014 due to avoiding performance level decreases experienced over time if the system is not replaced.

Rathdrum CT Upgrade Unit 1 to Mark VI Control: $45,000 (All in 2013)
In 2007, the Mark V controller on Rathdrum Unit 2 failed, taking the unit out of service for several months. A new Mark VI controller was installed in its place. This project replaces the old Mark V controller in Unit 1 with a Mark VI controller to match Unit 2. The Mark V technology is at the end of its life and is minimally supported by the manufacturer.

Generation Battery Replacement: $395,000 ($112,000 in 2013, $100,000 in 2014, and $183,000 in 2015)
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. There is also $115,000 in projected capital costs in 2016.

Kettle Falls Develop New River Wells: $1,615,000 (All in 2014)
The Kettle Falls Generating Station receives its water from the City of Kettle Falls through an agreement that dates to the construction of the plant in the early 1980's. That agreement expires next year and future water rates with the City of Kettle Falls will be higher, directly impacting the operating costs of the plant. The necessary new water rights have been procured and this project includes the construction of the water supply system to the plant that will be controlled and operated by the Company. O&M savings of $18,750 are expected in 2015 related to the reduction in the amount paid for water expense.

Kettle Falls Generation Station Ash Collector: $1,907,000 (All in 2015)
This project is to replace the mechanical ash collector at the Kettle Falls Generating Station. The current unit is the original plant equipment and requires frequent repair of metal surfaces due to ash abrasion, requiring plant outages. O&M savings are estimated to be $75,000 in 2015 due to the reduction of maintenance costs associated with ash abrasion.

Little Falls Powerhouse Redevelopment: $15,527,000 ($27,000 in 2013, $9,000,000 in 2014, and $6,500,000 in 2015)

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. There is also $9,000,000 in capital costs projected in 2016. An O&M Offset was included in the O&M Offset Adjustment in the amount of $5,000 ($3,250 WA). After revenue requirement was finalized, it was determined that no offsets exist for this business case as the associated savings are due to employee labor that will be redistributed to other projects.

Long Lake HED Replace Field Windings: $3,230,000 ($800,000 in 2014 and $2,430,000 in 2015)

Over the past 10 years, there has been a continuing decline in the insulation level on the generators at Long Lake. This decline is measured using Megger test instruments. Long Lake has experienced an increasing amount of forced outages and down time due to the condition of these units. There is also $170,000 in capital costs projected in 2016.

Nine Mile Redevelopment: $57,241,997 ($990,000 in 2013, $9,208,122 in 2014, and $47,043,875 in 2015)

This capital program is 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. Once operational in 2016, the new units will add 1.4 aMW of energy beyond the original configuration and 6.4 MW of capacity above current generation levels. 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
- other improvements will be made.

The fall 2013 Unit 4 overhaul includes new turbine runners, thrust bearings, and operating system. There is $13,800,983 in capital costs expected in 2016.

Peaking Generation: $2,000,000 ($1,000,000 in 2013, $500,000 in 2014, and $500,000 in 2015)

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). There is also $500,000 in capital costs expected in 2016.

Post Falls Intake Gate Replacement: $1,000 (All in 2013)

This project is essentially complete and involved replacing the wooden timbered head gates at Post Falls with new steel gates and modifying the structure to include a hoist system. Provisions for the gates were made to pull the gates out for easy maintenance purposes. This work also included installation of new controls and appropriate emergency power systems.

Post Falls South Channel Gate Replacement: $11,008,000 (All in 2015)

Avista has planned to maintain the south channel gates to comply with FERC Dam Safety directives. A pre-construction underwater investigation revealed that the condition of the concrete structure was very poor and would not handle the planned work. This resulted in an effort to evaluate options. This capital item includes preliminary engineering of different replacement options and project estimates. 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. An O&M Offset was included in the O&M Offset Adjustment in the amount of $5,000 ($3,250 WA). After the revenue requirement was finalized, it was determined that no offsets exist for this business case as the associated savings are due to employee labor that will be redistributed to other projects.

Regulating Hydro: $8,792,000 ($ 3,292,000 in 2013, $2,500,000 in 2014, and $3,000,000 in 2015)

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. There is also $3,000,000 in capital costs expected in 2016.

Clark Fork Settlement Agreement: $19,630,000 ($1,719,000 in 2013, $10,830,000 in 2014, and $7,081,000 in 2015)

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. There is also $21,846,280 in capital costs expected in 2016.

Spokane River Implementation PM&E: $7,137,000 ($1,860,000 in 2013, $4,815,000 in 2014, and $462,000 in 2015)

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. There is also $16,222,000 in capital costs expected in 2016.

Hydro Safety Minor Blanket: $185,000 ($50,000 in 2013, $65,000 in 2014, and $70,000 in 2015)

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. There is also $75,000 in capital costs expected in 2016.

Q. Would you please provide an update on the Colstrip Unit #4 outage?

A. Yes. Colstrip Unit #4 experienced an unplanned outage on July 1, 2013 resulting from damage caused by a ground fault on the "B" phase stator of the main generator. This damage required a rebuild of the Unit #4 generator. The unit was started under test conditions on January 23, 2014 and released for full operation on January 25, 2014.

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 3000 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 over 17,000 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 438 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 key 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 was initiated. 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 24 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.

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 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 design continue on two of the alternatives. 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 are required to address cavitations issues. Modification of the spillway crest prototype and retesting is anticipated in 2014.

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 (PM&E measures) across all five hydro developments. 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 are waiting for approval by the US Department of Interior, Bureau of Indian Affairs to continue implementing the plans. We completed a multi-year wetland mitigation project for 124 acres of property along the St. Joe River in 2013 and will be responsible for maintaining approximately half of it, which lies on Avista's property, for the License term. We also completed over one mile of erosion control along the same stretch of river in 2013, with approximately half being on Avista property.

We 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 boat launch improvements along the Coeur d'Alene and St. Maries Rivers. In Washington we completed the designs for ten boat-in-only campsites on Lake Spokane that will be developed in 2014, and completed other improvements at our overlooks and interpretive areas on Lake Spokane and in Nine Mile Falls. We purchased 109 acres of wetlands along the Little Spokane River and are currently developing a management plan for it, in order to fulfill required conditions.

In 2014, we will continue to develop and implement local, state, and federally required work plans to fulfill License conditions.

A number of the approved work plans require 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, which we began modeling in 2011. Avista is now in the process of having spillway modifications designed for construction to begin as early as 2015. The Company completed the proposed dissolved oxygen (DO) measure in the tailrace below Long Lake Dam and is continuing to evaluate potential measures to improve DO in Lake Spokane, the reservoir created by the Long Lake Dam. Initial estimates for measures to address TDG range between $7.0 and $17.0 million, and between $2.5 and $8.0 million to address DO in Lake Spokane. These estimates will be further refined as the relevant evaluations and studies are completed.

Q. Please describe further the work completed by the Company to study the total dissolved gas downstream of Long Lake Dam.

A. This was the subject of a deferred accounting order allowing the Company to seek recovery of costs in this rate case. The Long Lake development is one of five Avista hydroelectric developments that are a part of Avista's Spokane River Project. The Spokane River Project consists of five hydroelectric developments between Coeur d'Alene Lake in Idaho and Long Lake Dam in Washington (Post Falls, Upper Falls, Monroe Street, Nine Mile and Long Lake). The Spokane River Project is the subject of Federal Energy Regulatory Commission ("FERC") Project License 2545, a 50-year license issued by FERC on June 18, 2009.

Simultaneous to Avista's work on its Spokane River relicensing process (2002-2009), the Washington Department of Ecology ("Ecology") undertook a Dissolved Oxygen Total Maximum Daily Load ("TMDL") process to address impaired water quality in the Spokane River due to low dissolved oxygen levels. A TMDL is a requirement under the State of Washington's Clean Water Act obligations. One of the areas listed as "impaired" for low dissolved oxygen under the Clean Water Act includes Lake Spokane.

The TMDL, which is essentially a water quality cleanup plan, was a multi-year process that involved public and private entities that discharge wastewater into the Spokane River[3], and many stakeholders, including Ecology, the United States Environmental

[3] While Avista does not discharge into the Spokane River, Ecology, EPA, and others believe that the presence of the Long Lake Hydroelectric Facility increases the opportunity for algae growth. Algae absorbs oxygen when it decomposes.

Protection Agency ("EPA"), Washington Department of Fish and Wildlife, Idaho Department of Environmental Quality, Native American tribes and other parties. The TMDL process was ongoing when FERC issued the Project License in 2009 for the Spokane River Project.

The 2009 FERC Project License incorporated in its Appendix B the conditions of Washington State's Water Quality Section 401 Certification ("401 Certification") as mandatory conditions under the authority of the Clean Water Act, consistent with the Federal Power Act. Condition 5.6C relates to dissolved oxygen in Lake Spokane. The 401 Certification and FERC License require Avista to develop a Water Quality Attainment Plan ("Attainment Plan") to "improve oxygen conditions in Lake Spokane….sufficient to address its proportional level of responsibility, based on its contribution to the dissolved oxygen problem in the Lake." Condition 5.6C requires that the Attainment Plan be implemented over a 10-year period, with the potential of "alternative action[s]" being required should the Plan's results be insufficient after the initial 10-year period.

At the time the 401 Certification and FERC License were issued, the TMDL process was still ongoing, so Condition 5.6C served essentially as a placeholder until such time as the TMDL was completed.

The TMDL process continued subsequent to the issuance of the FERC License for Avista's Spokane River projects. In the TMDL discussions and negotiations, many stakeholders, including Department of Ecology staff, sought to require Avista to oxygenate or aerate Lake Spokane as a means to address low dissolved oxygen levels. Avista, for its part, was actively engaged in the TMDL process both to ensure that the determination of Avista's proportionate responsibility for the impairment issue was not overstated, as well as to promote alternatives to the oxygenation or aeration capital project. The suggested alternatives would serve to provide for long-term benefits to the Spokane River and Lake Spokane at a lower cost to the Company and its customers.

In early 2012, Ecology issued the final TMDL. As the TMDL was now complete, Condition 5.6C of the Section 401 Certification was amended, as was the 2009 FERC license. The issuance of the TMDL and FERC License amendment also started Avista's timeline for developing and submitting the Attainment Plan to Ecology. Avista developed the Attainment Plan in consultation with Ecology and, after Ecology's approval, submitted it to FERC for approval in October 2012. FERC subsequently approved the Attainment Plan.

As was discussed earlier, Avista actively participated in the TMDL process. In the final TMDL, the methodology for how Avista should address the low dissolved oxygen levels in Lake Spokane was left open for exploration in the Attainment Plan (i.e, it was not prescriptive in how Avista must address the issue). One of the methodologies to address this problem was to aerate or oxygenate the Lake. Such a facility would have either used trucked in liquid oxygen or ambient air, bubbled or pressurized respectively, through an extensive distribution system installed through much of the 23-mile long lake. Avista had estimated this project could have cost up to $8.0 million dollars to model, design and construct (not including additional property rights that may have been required), plus an additional $200,000 to $300,000 per year in ongoing operations and maintenance, including liquid oxygen delivery and use.

Through extensive modeling efforts, and through ongoing negotiation over a period of several years through the TMDL process, Avista was able to avoid the construction of an aeration facility. While Avista could have chosen to move forward with the more expensive capital project to address oxygen levels, the Company's additional efforts in evaluating alternatives resulted in the opportunity to choose a solution that is much less expensive for customers. Alternatively, Avista developed a 10-year implementation plan under which Avista is undertaking a number of smaller-scale efforts, including such items as removing non-native carp, removing non-native aquatic vegetation, educating shoreline landowners on proper vegetation management, and a number of other elements.

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. Washington's share of these costs was approximately $871,000.[4] As described by witness 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 three-year period beginning in 2015.

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

A. Yes it does.

[4] In Docket No. UE-131576 the Company sought, and received approval of (see Order No. 0l), an Accounting Order to defer the costs related to the improvement of dissolved oxygen levels in Lake Spokane. Order No. 01 authorized the Company to defer and transfer Washington's share of these costs (approximately $871,000) to FERC account 182.3. The Order also approved Avista's proposal for recovery and prudence of these costs to be determined in its next general rate case or in a separate filing.