Exhibit No.__(RJL-1T)

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-11_____

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. 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.

A table of contents for my testimony is as follows:

Q. Are you sponsoring any exhibits?

A. Yes. Exhibit No.__(RJL-2) includes Avista's 2009 Electric Integrated Resource Plan. Exhibit No. _(RJL-3) provides a forecast of Company load and resource positions from 2011 through 2020. Confidential Exhibit No.__(RJL-4C) includes Avista's Energy Resources Risk Policy.

II. RESOURCE PLANNING AND POWER OPERATIONS

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

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

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

Illustration No. 1: Avista's Generation

Avista-Owned Generation							
Hydroelectric Generation	**MW**		**Thermal Generation**	**MW**		**Natural Gas Peaking Generation**	**MW**
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						
Total Hydroelectric	**991**		**Total Base-Load Thermal**	**550**		**Total Peaking**	**236**
Total Owned Generation	**1,777 MW**						

In addition, the Company currently has long-term contractual rights for 134 aMW from Mid-Columbia hydroelectric projects in 2012, owned and operated by the Public Utility Districts of Chelan, Douglas and Grant counties. Avista also has a long-term power purchase agreement (PPA) in place 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.

Q. Would you please provide a summary of Avista's power supply operations and planning for 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. 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 are generally made in conjunction with the Integrated Resource Plan (IRP) and will typically include a Request for Proposals (RFP) or other market due diligence process.

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

A. Avista's 2009 electric Integrated Resource Plan (IRP) shows forecasted annual energy deficits beginning in 2018, and sustained annual capacity deficits beginning in 2019. [1] These capacity and energy load/resource positions are shown on pages 2-27 and 2-28, respectively of Exhibit No.__(RJL-2). However, our most recent load and resource projection, which is attached as Exhibit No. __ (RJL-3), indicates that the annual deficits have moved out another year. Therefore, Avista's current projection shows an annual energy deficit beginning in 2020 of about 19 aMW, and increasing to a 406 aMW deficit in 2031. The Company's January capacity resource position, based on an 18-hour peak event (6 hours per day and over 3 days), is currently projected to be surplus through 2021. Sustained annual capacity deficiencies, based on a January peak, begin at 148 MW in 2022 and increase to a 779 MW deficit in 2031. The Company's August capacity resource position, based on an 18-hour peak event, is currently projected to be surplus through 2018. Sustained annual capacity deficiencies, based on an August peak, begin at 56 MW in 2019 and increase to a 667 MW deficit in 2031.

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

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

A. The Company will be guided by its Preferred Resource Strategy. The current Preferred Resource Strategy is described in the 2009 Electric IRP, which is attached as Exhibit No.__(RJL-2). The IRP provides details about resource needs, specific resource costs, resource operating characteristics, and the scenarios used for evaluating the mix of resources for the Preferred Resource Strategy.

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

Avista's 2009 Preferred Resource Strategy includes 5 MWs of distribution efficiencies, 339 MWs of energy efficiency, 5 MWs of upgrades to existing hydroelectric plants, 750 MWs of gas-fired combined-cycle combustion turbine (CCCT), and 350 MWs of wind located in the Pacific Northwest. The timing of these resources as published in the 2009 IRP is shown in Illustration No. 2 below.

Illustration No. 2: 2009 Electric IRP Preferred Resource Strategy

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

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.

Avista plans to meet its RPS obligations in the near-term through a combination of qualified hydroelectric upgrades and the purchase of renewable energy credits (RECs). In March 2009 Avista purchased 5.7 aMW of credits (RECs) per year from 2012 through 2015 to satisfy the RPS requirement through 2015. Illustration No. 3 below shows Avista's projected REC position from 2012 through 2020. The RECs projected to be available to the Company as shown in Illustration No. 3 are predicated on the hydroelectric resource upgrades qualifying for the apprentice labor credit. There is still some uncertainty in the apprenticeship credit rules. If the ultimate rule is interpreted such that apprenticeship credits do not apply, then the amounts shown would be decreased.

Illustration No. 3: Washington Renewable Portfolio Standard Requirements

Year	Percentage of WA Load	Total Projected Need (RECs/aMW)	RECs Available* (RECs/aMW)	Surplus/ (Deficiency)** (RECs/aMW)
2012	3%	18.9	23.5	4.6
2013	3%	19.0	25.8	6.9
2014	3%	19.2	27.7	8.5
2015	3%	19.4	27.7	8.3
2016	9%	58.8	22.0	(36.8)
2017	9%	59.3	22.0	(37.4)
2018	9%	59.9	22.0	(37.9)
2019	9%	60.4	22.0	(38.4)
2020	15%	101.4	22.0	(79.4)

* Including current qualifying resources, planned hydro upgrades, and purchased RECs. This is predicated on the resources qualifying for apprentice credits.

** Does not include banking of qualified RECs from one year to the next.

Q. Can you provide some background information regarding how Avista developed it approach to meet its Washington renewable energy goals for the 2012 through 2015 time period?

A. Yes. The Company began studying the issue of how to best meet the goals of the Energy Independence Act (I-937) shortly after passage of the initiative. The primary objective of the Company's work was to determine how to best meet the initial 3% renewable portfolio standard obligation in light of our projected load and the long-term projected costs of meeting those goals. The amount of REC needs continued to evolve as we developed a better understanding of I-937 and participated in the rulemaking process. Based on the Company's analysis of I-937, it was determined that a relatively small amount of qualified renewable generation would be needed to satisfy obligations based on the Company's projections for a combination of qualified hydroelectric upgrades and apprentice labor benefits. The Company's

2007 IRP indicated energy and capacity needs beginning in 2011. A portion of those needs were going to be met with renewable generation. Over time, the Company's resource position needs changed so that the energy and capacity needs moved out further. This eventually led to a decision in October 2008 to purchase 50,000 RECs per year (about 5.7 aMW) to meet short-term I-937 goals from 2012 through 2015.

Q. What process did the Company use to determine the amount of RECs to purchase?

A. Following a 2008 decision to postpone the acquisition of additional renewable generation beginning in 2012, estimates of the amount of RECs needed to satisfy I-937 goals were developed. It was estimated at the time that approximately 5.7 aMW or 50,000 RECs would be needed to meet the I-937 goal. The overall amount of REC needs included planning margins to account for hydroelectric and load variability. The goal was to secure a competitive REC price for the 2012 through 2015 period. Analysis indicated that the acquisition of the small amount of additional RECs needed to cover the 2012 – 2015 time period would be a reasonable and cost-effective approach to meeting the Company's I-937 renewable energy requirements given the cost and availability of RECs at that time. It was expected that the Company's long-term REC needs, which increase to 9% of load in 2016, would be met with the addition of qualified renewable generation to the Company's resource mix. More details about the Company's long-term REC needs can be found in our Integrated Resource Plan.

Q. How did the Company go about purchasing the RECs?

A. Integral to the 2008 assessment of alternatives to meet I-937 requirements, market inquiries were made concerning the cost and availability of I-937 qualified RECs for the 2012 through 2015 period. The Company began making inquiries about RECs through several brokers in September 2008, since there was, and still is, no liquid REC market in the Pacific Northwest. Brokers indicated that I-937 qualified RECs were available at that time period in the $12 to $17 per REC range. They further indicated that the renewable requirements in California may increase the market price of these RECs over to $20 per REC in the time period being considered.

From mid-October through November 2008, the Company discussed potential REC purchases and pricing with a number of counterparties and brokers. By late November, it became clear that realistic market opportunities for RECs meeting the Company's criteria were generally not available below a price of approximately $15 per REC. All REC offers had been received by December 2008 and the winning proposal selected for negotiation was from an entity with I-937 qualified surplus RECs from the Stateline Wind Project. Contract negotiations for the REC purchase began in December 2008 and a contract for 50,000 RECs per year from 2012 through 2015 was executed in March 2009.

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

A. Yes. Avista has continued to monitor renewable resource market conditions, particularly with respect to projects bid into its 2009 renewable resource RFP. Avista was recently made aware of a significant drop in prospective project costs associated with construction of new wind generation facilities that are still in position to take advantage of currently available near-term tax incentives for projects brought on-line prior to December 31, 2012. The material drop in project cost, combined with the Commission's recent Report And Policy Statement Concerning Acquisition Of Renewable Resources By Investor-Owned Utilities (Docket No. UE-100849), were factors considered in the Company's decision to issue a request for proposals (RFP) for up to 35 aMW of renewable energy in February 2011. The 2011 renewable resource RFP seeks qualifying projects or project output for the 2012 – 2032 time period. Avista stated in the RFP that the Company expected that bids should not exceed $62/MWh and that Avista would not submit a self-build option. While the Company does not have a need for renewable energy until 2016, the combination of the significant drop in project cost and the substantial tax incentives available today for projects completed by December 31, 2012 point toward long-term benefits for customers compared to the alternative of waiting to a date closer to 2016 when renewable requirements are set to increase and, at that later time, tax incentives, attractive project pricing, and particular attractive wind project sites may no longer be available to Avista.

Q. What is the status of the 2011 renewable resource request for proposals?

A. The Company has completed the first two rounds of screening and is in the final rounds of negotiations, with a decision expected before the end of June.

Q. What is the status of the Reardan wind project?

A. Avista continues to study the Reardan wind project site in preparation for later development. The Company expects to issue an RFP at a later date to meet additional future resource needs, and expects that the Reardan project would be considered in that later process. The Company chose not to introduce a Reardan project option into the 2011 renewable resource RFP primarily because of the short time frame available to secure competitive bids for turbines and balance of plant construction. When the Company decided in mid-February to initiate a 2011 renewable resource RFP, potential bidders had indicated that they would need a power purchase agreement executed by early to mid-May in order to be able to complete a project that would qualify for all of the available tax incentives, including the Washington state sales tax incentive that is scheduled to decrease on July 1, 2011 and end on June 30, 2013. Therefore, Avista sought projects that were ready to be built and required bids to be due by March 7, 2011.

The competitive bidding for turbines and balance of plant work necessary to prepare the Reardan project for evaluation did not fit into the short bidding window.

Q. Can you provide an update of the Company's evaluation of a direct connection of Avista transmission to the Bonneville Power Administration's Lancaster substation?

A. Yes. Avista is currently engaged in a process with the Bonneville Power Administration (BPA) to jointly study interconnecting Avista's transmission lines to the BPA Lancaster substation, where the Lancaster plant is currently interconnected. The proposed project would interconnect the transmission systems of BPA and Avista at the BPA Lancaster substation. An Avista transmission interconnection to the BPA substation, however, would continue to utilize the BPA Lancaster substation. The costs associated with continued use of the substation would be subject to negotiation between the Company and BPA.

Pursuant to Avista's Line and Load Interconnection request dated September 2, 2009, Bonneville completed its Line and Load Interconnection System Impact Study on August 20, 2010 and is in the process of finalizing its Line and Load Interconnection Facilities Study, currently expected to be completed in June of 2011. Upon completion of the Line and Load Interconnection Facilities Study, Bonneville will tender a Construction Agreement to Avista. Bonneville has communicated to Avista that its current engineering and construction schedule suggests that the Avista-Bonneville Lancaster 230kV interconnection may be constructed in 2013.

Construction of a stand-alone Avista interconnection (where the Lancaster project is disconnected from the Bonneville system and connected directly to the Avista system) would not provide the reliability benefits and additional import capacity that an Avista-Bonneville 230kV transmission interconnection provides, therefore, this form of a self-build option has not received any further consideration as part of the joint study work.

Q. What has been done to keep the Commission Staff informed about the proposed interconnection of Lancaster to Avista transmission, as requested on page 11 in Order 07 of Docket No. UE-100467?

A. A conference call was held on March 23, 2011 between Avista personal and Commission Staff to provide an update and answer questions about the interconnection of Lancaster to Avista transmission. The Company provided an overview of the BPA process, the progress to-date and next steps. BPA had completed a system impact study in August 2010 and at the time of the March 2011 update, Avista expected BPA to have completed the facility study by early April 2011. However, BPA has revised the schedule to reflect a June 2011 facility study completion. After completion of the facility study, BPA and Avista would expect to enter into a contract covering the construction of facilities and costs of the project.

III. RISK MANAGEMENT POLICY

Q. Can you 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 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 36 months), the short-term (monthly and quarterly periods up to approximately 36 months), and the immediate term (present month). A copy of the current Energy Resources Risk Policy is in Confidential Exhibit No.__(RJL-4C).

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. Several factors, including the variability associated with loads, hydroelectric generation, and electric power and natural gas prices, are considered in the decision-making process regarding procurement of electric power and natural gas for generation.

The Company aims to strategically develop or acquire long-term energy resources as suggested by the Company's Integrated Resource Plan acquisition targets, while taking advantage of competitive opportunities to satisfy electric resource supply needs in the long-term period. On the other end of the time spectrum, electric power and 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, 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 or a long position. A calendar quarter occurring at a future time is an example of such a forward period. A short position situation occurs when the Company has not yet purchased the fixed price fuel to generate power, nor, alternatively, has it purchased fixed price electric power from the market, in order to meet a projected average load for a forward time period. The amount of load that is in excess of the amount of fixed price power available for that forward time period represents an open short position. A long position situation occurs when the Company has fixed priced generation or fueled generation above its expected average load needs (e.g. hydroelectric generation during the May-June time period) and has not yet made a fixed price sale of that surplus power into the market in order to balance resources and loads. The amount of fixed priced generation that is in excess of the average load for that forward period represents an open long position.

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. Please describe the Electric Hedging Plan.

A. The Electric Hedging Plan is detailed in Exhibit 2 of the Risk Policy (Confidential Exhibit No. __(RJL-4C)). The use of the Electric Hedging Plan approach, as outlined in Exhibit 2 of the Risk Policy, describes what is essentially a layering strategy aimed to average-in purchases or sales of electric power and natural gas generation fuel over a period of time. This approach aims to smooth the impacts of price volatility in the energy markets.

The Electric Hedging Plan in the Risk Policy describes the basic analytic approach that the Company utilizes to guide hedging electric power positions over the short-term, prompt month, and through the next 34 to 36 month period. The plan guides management of financially open positions in increments of 25 aMW. Open financial positions that exceed 25 aMW are cured with a variety of transactions as permitted under the Risk Policy including fixed price physical power, fixed price physical natural gas, and combinations of financial fixed for floating swap transactions coupled with index physical transactions. The Company uses statistical price movement triggers, based on historic volatility in the forward power and natural gas markets, the entire short-term period and also uses triggers based on expiring time periods in the nearer-term period up to 18 months in the future to trigger transactions to cure open positions. The trigger indicators from the Hedge Scheduler statistical model are indicated on the daily position reports and provide guidance to management for prospective forward transactions. Additional details concerning the how the Hedge Scheduler works can be found in Exhibit 2 of the Energy Resources Risk Policy. (Confidential Exhibit No. __(RJL-4C)).

Q. What updates has the Company provided concerning the Electric Hedging Plan?

A. Company representatives met with Commission Staff in early February 2011 and, as part of a general update on resource matters, provided an overview and answered questions concerning the operation of the Electric Hedging Plan and the technical models that support it.

Q. Can you provide some additional background regarding how the near-term hedging plan operates?

A. Yes. The Electric Hedging Plan (sometimes referred to as the "Hedge Scheduler") operates somewhat differently between two separate time periods within the short-term 36-month window. The period beginning with the prompt month and up to approximately 18 months into the future, as determined by the monthly and quarterly tradable forward periods, focuses on mechanically layering in transactions, as well as taking advantage of price declines in electric energy or fuel prices. The period approximately 19 months to 36 months into the future, as determined by the number of quarterly tradable forward periods, primarily looks for declines in electric energy or fuel prices.

The Electric Hedging Plan is essentially a layering strategy designed to average-in purchases and sales of electric power and natural gas fuel over a period of time. This approach aims to smooth the impacts of price volatility in the energy markets over time. The Company's Electric Hedging Plan is more specifically described in an appendix of the Company's Energy Resources Risk Policy.

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

A. As discussed previously, power supply may have an open financial position that results from a difference between load requirements and electric resources that are fixed price in nature or for which fixed price fuel has been purchased. Surplus positions occur when resources exceed load requirements, and deficits occur when load requirements exceed resources. The power supply position considers all of the variables that affect short-term power supply. The dynamic nature of the power supply position is actively managed "by establishing processes for future load and obligation estimation, resource estimation, and management of the expected net surplus or deficit Short-Term position". (Confidential Exhibit No.__(RJL-4C) at p. 3) The power supply position is managed by the Director of Power Supply. Similar types of position issues are also addressed in regards to natural gas supplies and are managed by the Director of Gas Supply. Any changes to practices are communicated to the Risk Management Committee.

The Risk Management Committee (RMC) is comprised of Avista management, appointed by the Chief Executive Officer, who is not directly part of Energy Resources operations. The RMC provides an oversight and advisory role concerning energy resource management and wholesale energy market risk policies and adherence to those policies.

Electric loads and obligations are estimated "based on analysis of historic loads, adjusting for weather variability, expected additions or decreases in large customer loads, all known wholesale contract obligations, and adjustments as necessary based on analysis of prior estimating accuracy and other factors". (Confidential Exhibit No.__(RJL-4C) at p. 3) Electric resources are estimated based on expected output after consideration for variability in conditions such as streamflow, forced outages, maintenance, and environmental concerns.

Electric surplus and deficit positions are hedged using the Electric Hedging Plan as a guide and may be adjusted by management judgment depending upon the circumstances of a particular surplus or deficit situation. The short-term electric position report is distributed each business day.

IV. GENERATION CAPITAL PROJECTS

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

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

Illustration No. 4: Noxon Rapids Upgrades

Noxon Rapids Unit #	Schedule of Completion	Additional Capacity	Efficiency Improvement
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%

The Noxon Unit #1 work consisted of the replacement of the stator core, rewinding the stator, installing a new turbine and performing a complete mechanical overhaul. This upgrade increased the Unit's energy efficiency by 4.16%, and increased the unit rating by 7.5 MW. The upgrade also fixed several reliability concerns for the Unit including mechanical vibration and stator age. This work was completed in 2009. The costs and additional generation of this project were approved for recovery in Docket No. UE-090134.

The Noxon Unit #3 upgrade, completed in May 2010, increased energy efficiency by 4.15%, and boosted the unit rating by 7.5 MW. The costs and additional generation for Unit #3 were approved for recovery in Docket No. UE-100467.

Noxon Unit #2 is having a new turbine installed and complete mechanical overhaul which is being completed in May of this year. This upgrade is projected to increase the efficiency of Unit #2 by 2.42% and boost the unit rating by 7.5 MW.

The upgrade work at Noxon Unit #4 will involve the installation of a new turbine and a complete mechanical overhaul starting in August 2011 and ending in May 2012. The Unit #4 upgrade is projected to increase efficiency by 1.49% and increase the unit capacity rating by 7.5 MW.

The costs associated with Noxon Unit #2, which will be completed in May 2011, will total approximately $9.1 million (system), and Unit #4, planned for completion in May 2012, will cost approximately $8.8 million (system). Company witness Ms. Andrews incorporates the Washington share of these costs in her adjustments. The increased generating capability from these units is reflected in Mr. Kalich's $\text{AURORA}_{\text{XMP}}$ modeling of pro forma power supply costs.

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

A. Yes. The total 2011 generation projects included in the Company's case, as identified by Mr. DeFelice and described below, total $21.4 million on a system basis. The 2011

Noxon Unit #2 upgrade project discussed above is $9.1 million of this total. In addition, there are five other generation capital projects totaling $12.3 million (system), as discussed further below.

Thermal - Colstrip Capital Additions- $5,886,000
Colstrip capital additions in 2011 include major work on the ash storage ponds for Units 3 and 4. This project will increase the capacity of the ponds to their final permitted level and is necessary for continued plant operation. New Low Pressure Turbine Rotors are going to be installed on Unit #3. The rotor purchase and installation is a multi-year project which began last year and will be completed in June of this year. The Unit #3 generator is also scheduled to be re-wound during this year's outage in order to extend its life and improve reliability. We are also performing an overhaul of Unit #3 which will include a variety of capital projects to increase safety and reliability. A sampling of these projects include: overhaul intermediate pressure turbine, distributed control system upgrade work, circulating water pump and motor rebuild, steam sample line replacement, induced draft fan motor rewind, induced draft fan spare, scrubber mist eliminator replacement, soot blower retract replacement, coal mill hydraulic replacement, and boiler. The overhaul is part of the ongoing maintenance program to maintain plant reliability and performance.

Hydro – Cabinet Gorge Capital Project - $1,490,000
Capital projects being completed at Cabinet Gorge include the repair and replacement of the discharge ring, replacement of the governor on Unit #1, and the replacement of the intake gate controls. The governor on Unit #1 is being replaced because of reliability issues. We have experienced several problems with the governor system and the particular model in place is no longer being supported by the manufacturer. We do have a limited number of spare parts for the governor system, but there are components that could pose a significant challenge to find replacements to return the unit to service in a timely manner if those components failed. The intake gate controls date back to the original commissioning of the project. The contactors and control switches are no longer dependable and their functionality has become increasingly intermittent. The gate control work involves the replacement of the original motor controls and switches with an automated control scheme.

Hydro – Post Falls Capital Project - $1,240,000
This project consists of the replacement of the intake gates. The rack and pinion system to raise and lower the intake gates has aged to the point where they are experiencing an increasing number of problems and occasional failures. The gate drive system presents a personnel hazard which can be designed away with a new system. The wood timber gates also need to be replaced because of age. A new fabricated steel vertical lift gate system will be installed in its place.

Hydro – Clark Fork Implementation PM&E Agreement - $1,468,000
The Clark Fork Implementation PM&E agreement capital expenditures include the acquisition of property rights for recreational improvements or habitat restoration. Three major acquisitions currently being pursued include the fee title acquisition of the Cabinet Gorge RV Park to meet

future recreation needs; fee title acquisition of riparian habitat on a tributary in Idaho to protect bull trout spawning and rearing habitat; and acquisition of a conservation easement to protect riparian habitat on the Bull River in Montana. Numerous ongoing recreation site improvements include the replacement of boat ramps, docks, and restrooms. upgrading electrical and septic systems, and trail development and improvements. Habitat enhancement projects include improvement and maintenance of existing wetlands on the Noxon Rapids and Cabinet Gorge reservoirs, tributary habitat enhancements such as culvert replacement, stream bed reconstruction and riparian re-vegetation and protection to improve passage, spawning and rearing for native salmonids.

Hydro – Spokane River Implementation (PM&E) - $2,243,000

The Spokane River Project capital projects fulfill FERC's license requirements for aesthetic spill channel modifications at Upper Falls, and numerous recreation site improvements at Nine Mile and Lake Spokane (the Long Lake Dam reservoir). The aesthetic spill channel modification is a mandatory condition, which was included in the License as part of the Washington 401 Water Quality Certification, whereas the recreation projects are FERC's own License requirements. This year we are modeling a number of potential total dissolved gas remedies for Long Lake Dam, and monitoring low dissolved oxygen in the tailrace to determine if the improvements we installed last year will sufficiently meet the State's water quality standards. We are currently working on the channel modifications at Upper Falls, and the required Nine Mile and Lake Spokane recreation projects.

Ms. Andrews incorporates Washington's share of these capital project additions in her adjustments.

Q. Please provide a summary of the generation capital expenditures in this case?

A. Illustration No. 5 is a table of the generation capital projects included in this case.

<u>Illustration No. 5: Generation Capital Projects Summary</u>

Project Name	**Capital Costs (000's) (System)**
Noxon Rapids Unit #2	$9,110
Noxon Rapids Unit #4	$8,757
Colstrip Capital Additions	$5,886
Cabinet Gorge Capital Project	$1,490
Post Falls Capital Project	$1,240
Clark Fork Implementation	$1,468
Spokane River Implementation	$2,243

V. HYDRO RELICENSING

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

A. Yes. Avista received a new 45-year FERC operating license for its Cabinet Gorge and Noxon Rapids hydroelectric generating facilities on 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 2,620 acres of bull trout, wetlands, uplands, and riparian habitat. More than 35 individual stream habitat restoration projects have occurred on 25 different tributaries within our project area. Avista has collected data on nearly 12,000 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 313 adult bull trout, with over 150 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 both a permanent upstream adult fishway for Cabinet Gorge and a permanent tributary trap for Graves Creek (an important bull trout spawning tributary).

Recreation facility improvements have been made to over 23 sites along the reservoirs. Avista also owns and manages over 100 miles of shoreline that includes 3,500 acres of property to meet FERC requirements to meet our 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 streamflows 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 work continues. Implementation of the addendum is expected to be significantly less costly than the Tunnels Project Plan.

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 filed applications with FERC in July 2005 to relicense five of its six hydroelectric generation facilities located on the Spokane River. The Spokane River Project includes the Long Lake, Nine Mile, Upper Falls, Monroe Street, and Post Falls facilities. Little Falls, the Company's sixth facility on the Spokane River, is not under FERC jurisdiction, but operates under separate Congressional authority. In June 2009, FERC issued a new 50-year license for the Spokane River Project, incorporating key agreements with the Department of Interior and other key parties. Implementation of the new license began immediately. Over 40 work plans were 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 of other mandatory conditions issued by the U.S. Department of Interior. In 2010, Avista began implementing a number of water quality, fisheries, recreation, cultural, wetland, aquatic weed management, aesthetic, operational and related conditions (PM&E measures) across all five hydro developments. In 2011, we will continue to implement approved work plans and will begin implementing the few remaining outstanding ones, once they are approved by FERC.

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 the Long Lake facility and dissolved oxygen in Lake Spokane, the reservoir created by the Long Lake facility. 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 dissolved oxygen in Lake Spokane. These estimates will be further refined as the relevant evaluations and studies are completed.

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

A. Yes it does.