BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-05____________

DIRECT TESTIMONY OF

RONALD R. PETERSON

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

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

A. My name is Ronald R. Peterson. I am employed as Vice President of Energy Resources by Avista Corporation at 1411 East Mission Avenue, Spokane, Washington.

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

A. I began my career at Avista Corp. in 1975 after graduating from Washington State University with a degree in business administration, majoring in accounting. I passed the Washington State CPA examination in 1976 and worked as a staff accountant in a variety of positions until 1987, when I became Supervisor of the Company's Corporate Accounting function. In 1991, I was selected Customer Service Manager, and in 1992 was elected Treasurer. I was elected Controller and assumed the Director of Information Services responsibilities in 1996. In 1998, I was elected Vice President and Treasurer. I served as both the Corporate Treasurer and Utility Controller beginning in August 2001. I was appointed to my current position in March 2003.

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

A. My testimony will provide an overview of Avista's resource planning and power operations. I will provide an update on the Company's hydro upgrades, a status report on the Company's FERC license commitments at the Clark Fork River hydroelectric projects, and the current re-licensing effort for the Spokane River hydroelectric projects. Next, I will discuss the Company's acquisition of the second half of Coyote Spring 2 (CS2). I will explain the Company's proposal to eliminate the deadband from the ERM calculations. Finally I will address the Company's proposed treatment of expenses related to two small generating units and the Company's proposed treatment of production tax credits related to its Kettle Falls wood-fired plant.

A table of contents for my testimony is as follows:

I am sponsoring Exhibit Nos.__(RRP-2) through __(RRP-14), which were prepared under my direction:

Exhibit No.	Description
RRP-2	Resource Planning and Operations
RRP-3	Photo – Cabinet Gorge Hydroelectric Project
RRP-4	Map – Spokane River Hydroelectric Projects
RRP-5	Location of Coyote Springs Plant Relative To Avista Utilities Service Area
RRP-6	Excerpts from 2000 Updated Integrated Resource Plan
RRP-7	Coyote Springs 2 – Letter of Intent
RRP-8	Coyote Springs 2 – Purchase and Sale Agreement
RRP-9	2003 Integrated Resource Plan Excerpts re: Preferred Resource Mix
RRP-1-	August/September 2004 Loads and Resources Position
RRP-11	May 2004 CS2 Analysis
RRP-12	September 2004 CS2 Analysis
RRP-13	Navigant Consulting CS2 Analysis and Valuation
RRP-14	Kettle Falls Production Tax Credit Calculation

II. AVISTA'S RESOURCE PLANNING AND POWER OPERATIONS

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

A. Yes. Avista's resource portfolio consists of a diverse mix of resources consisting of hydroelectric generation projects, base-load coal and natural gas fired thermal generation facilities, wood waste-fired renewable generation, natural gas-fired peaking generation projects, long-term contracts including wind generation and Mid-Columbia hydroelectric generation, and market power purchases and exchanges. For 2005, Avista-owned generation facilities have a total capability of approximately 1815 MW, of which 54% is hydroelectric and 46% thermal. The following table summarizes the present capability of Avista's[1] generation resources.

Company-Owned Projects	MW
Noxon Rapids	527
Cabinet Gorge	261
Post Falls	18
Upper Falls	10
Monroe Street	15
Nine Mile	25
Long Lake	88
Little Falls	36
Total Hydroelectric Generation	980
Colstrip Units 3 and 4	222
Coyote Springs 2	285
Kettle Falls	53
Total Base-Load Thermal Generation	560
Northeast CT	67
Kettle Falls CT	7
Boulder Park	25
Rathdrum CT	176
Total Natural Gas Peaking Generation	275
Total Generation	1,815

[1] All generation projects are owned by Avista with the exception of the Rathdrum CT which is leased from WP Funding LP, an entity that is included in Avista Corp.'s consolidated financial statements.

In addition to the above mix of owned and leased generation resources, the Company's resource portfolio also includes specific resources for which the Company has contractual rights for a portion of project output. The Company has long-term contractual rights for a total of 138 MW of capability from the Mid-Columbia generation projects that are owned and operated by the Public Utility Districts of Grant, Chelan and Douglas counties. The Company also has a 10-year contract in place for the purchase of 35 MW of wind generation capability from the Stateline Wind Project.

Q. Would you please provide a brief overview of Avista's resource planning and power supply operations?

A. Yes. As explained above, Company uses a combination of owned, leased and contracted-for resources to serve its retail and wholesale load requirements. Dispatch decisions related to these resources are made within the Energy Resources Department of Avista Utilities. The Department conducts studies on a regular basis to determine the need for capacity and energy resources on a short-term, medium-term and long-term basis. The Company enters into short-term and medium-term wholesale sales and purchase transactions to balance its resources with load requirements. Longer-term resource decisions related to building new resources, upgrades to existing resources, demand-side management (DSM) and long-term contract purchases are generally made in conjunction with the Company's Integrated Resource Plan (IRP) and RFP processes. The Company, however, also acquires resources outside of an RFP process. Exhibit No.__(RRP-2) provides additional details related to Avista's resource planning and power operations, as well as a tabulation of its projected loads and resources for the next ten years.

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

A. With the second half of CS2, the Company is currently in a balanced to surplus energy position for years 2006 through 2009 on an average annual basis. However, as I will explain later in my testimony, there are monthly and quarterly deficits and surpluses within the years. In general terms, the Company's annual energy net resource position becomes deficient in 2010 and increases substantially in 2011 and beyond. The average annual energy resource deficiency beginning in 2010 is 34 aMW and increases to 308 aMW in 2015. Similarly, the Company's capacity resource position is either surplus or nearly balanced through 2009. Capacity deficiencies begin in 2010 at 67 MW and increase to 481 MW in 2015.

Q. How will the Company plan to meet the future resource needs beginning in 2010?

A. The Company plans to continue to pursue the preferred resource strategy laid out in its 2003 IRP. The development of the Company's 2005 IRP is in progress. The report is scheduled for release in September of this year. The Company would expect to continue to evaluate a mix of options including medium-term market purchases, generation ownership options, hydroelectric upgrades, renewable resource options, demand-side management options, long-term contracts, and generation lease options or tolling[2] options. As stated earlier, longer-term resource decisions are generally made in conjunction with the Company's IRP and RFP processes. The Company, however, is not precluded from acquiring resources outside of an RFP process. The Company's preferred resource strategy includes a mix of combined cycle

[2] "Tolling" is an energy conversion service whereby a provider takes customer supplied natural gas and converts it to an amount of electric energy which is delivered to the customer as determined by a defined conversion ratio. The conversion ratio can be tied to the heat rate and variable operating costs of a generating plant. The fixed cost of the

combustion turbine, wind, coal-fired, and simple cycle natural gas combustion turbine generation.

In addition to the recent acquisition of the second half of CS2, the Company has added a variety of resources to its portfolio in recent years, including: a ten-year agreement for 35 MW of wind generation capability (estimated 8-10 aMW of annual energy); medium-term purchases of 100 MW for the period 2004 through 2010; purchase of approximately 7 aMW of small hydroelectric generation from the City of Spokane; hydroelectric upgrades at Cabinet Gorge, and a new purchase agreement signed with Grant County PUD for a share of the output from the Priest Rapids and Wanapum hydroelectric projects beginning in 2005. The Company has continued to evaluate and acquire demand side management (DSM). For example, Avista has acquired approximately 83 aMW of DSM over the past fifteen years. Avista continues to acquire cost-effective DSM and anticipates acquisition of an additional 25 aMW over the next five years.

Q. How does Avista manage risk in its short-term power systems operations?

A. Avista Utilities uses a variety of techniques to manage its business risks. The Risk Policy is one risk management tool. The overall purpose of the Risk Policy is to provide general guidance to the Energy Resources workgroup with regard to the management of the company's energy risk exposure, as it relates to electric power or natural gas resources.

The management of volumetric limits for the imbalance between projected loads and resources for an 18-month forward period is part of the Risk Policy guidance. The Risk Policy also provides structure for the appropriate management approvals for longer-term transactions depending on the term and time of delivery into the future.

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plant can be covered in fixed fees charged by the tolling service provider. Tolling service may be contingent on the

The purpose of the Risk Policy is not to develop a specific procurement strategy for buying or selling power or natural gas fuel for generation at any particular time. Rather, several factors, including the variability associated with loads, hydroelectric generation, and electric power and natural gas prices, are considered in the decision-making process with regard to procurement of electric power and natural gas fuel for generation under the Risk Policy.

III. HYDRO UPGRAGES AND HYDRO RELICENSING

Q. Please provide an update on generation upgrades on the Clark Fork River.

A. The Company completed an upgrade of the Cabinet Gorge Project Unit #2 in March 2004. This project consisted of removing the original 1952 propeller runner and replacing it with a modern design mixed-flow runner. Following the upgrade, the Company realized an increase in capacity from 55 MW to 72 MW and an increase in energy of approximately 3 aMW due to the increased efficiencies from the new design.

The Company completed a similar upgrade project in 2001 for the Cabinet Gorge Project Unit #3. The capacity of the unit was also increased from 55 MW up to 72 MW and an estimated 4.5 aMW of additional energy is produced as a result of the increased efficiency.

The Company is continuing to look for opportunities for additional efficiency upgrades, in conjunction with other maintenance work, on unit #4 at Cabinet Gorge and units #1, #2, and #3 at the Noxon Rapids Project.

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

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operation of a specific generation plant.

A. Yes. Avista received a new 45-year FERC operating license for its Cabinet and Noxon hydroelectric generating facilities on March 1, 2001. The Company has made significant progress toward meeting the goals, terms, and conditions of the Protection, Mitigation and Enhancement (PM&E) measures under the license. Specifically, the purchase of more than 1,100 acres of important bull trout, wetland, and associated upland habitat, will ensure protection of these resources. The fish passage program has reestablished bull trout connectivity between Lake Pend Oreille and the Clark Fork River tributaries above Cabinet Gorge Dam. Over the last four years, Avista has developed two experimental fish passage facilities, and has radio tagged and safely transported adult bull trout above Cabinet Gorge Dam. Once the fish are transported, implementation staff monitor their movement and spawning efforts. Juvenile bull trout on their downstream migration are collected in tributary streams and transported to the Clark Fork River downstream of Cabinet Gorge Dam.

In addition, recreation facility improvements have been made to 19 different sites along the reservoirs. These upgrades include better recreational access, and new signage, interpretation and education material. Finally, tribal members continue to monitor known cultural and historic resources located within the project boundary, to ensure that these sites are appropriately protected.

When the new Clark Fork license was received, the high levels of total dissolved gas occurring during spill periods at Cabinet Gorge Dam was an issue that remained unresolved. A plan to mitigate these gas levels has been developed with stakeholders including the Idaho Department of Environmental Quality. The plan calls for the modification of an existing diversion tunnel. The tunnel modification would be completed by 2010 at an estimated cost of

$37 million. If needed, the modification of a second tunnel would occur within 10 years of completion of the first tunnel. The second tunnel would be constructed only after an analysis of the performance of the first tunnel and an evaluation of the environmental benefits. A photograph of the Cabinet Gorge project and the existing tunnels is provided as Exhibit No.__(RRP-3).

The Company has not proposed an increase in rates in this filing related to these costs. The costs will be capitalized and their recovery will be addressed in a future proceding.

Q. Would you please give an update on the status of your efforts to relicense the Spokane River Hydroelectric Project?

A. Yes. The Company is in the process of preparing a relicensing application related to five of its six hydroelectric generation projects located on the Spokane River. These projects, which are all under one FERC license, include Long Lake, Nine Mile, Upper Falls, Monroe Street, and Post Falls. Little Falls, the Company's sixth project on the Spokane River, is not under FERC jurisdiction but instead operates under a separate Congressional authority. Exhibit No.__(RRP-4) includes a map of the Spokane River showing the location of the Company's six hydroelectric projects.

The five FERC jurisdictional projects have a total generating capacity of 156 MW, and average annual energy production of approximately 105 aMW. Our current license for these Spokane River projects expires in August 2007, and the Company is planning to file a new application with FERC in July 2005. We are developing that application using FERC's alternative licensing procedures. Since 2001, we have been working with numerous stakeholders to understand and resolve issues related to the Spokane River Project. That consultation has occurred within five technical work groups and a lead, or plenary group, and numerous subgroups. The Company issued a draft license application for 90-day public comment in February of this year. A comprehensive agreement has not been reached at this point and negotiations are continuing with the numerous interested parties.

The Company has not proposed an increase in rates in this filing related to the costs associated with these relicensing efforts. The Company plans to defer the costs and address recovery of them in a future rate filing.

V. HISTORY OF COYOTE SPRINGS 2 AND AVISTA'S ACQUISITION

Q. Please provide a brief description and history of Coyote Springs 2.

A. CS2 is a 280 MW natural gas-fired, combined-cycle combustion turbine project, located in Morrow County, Oregon. Page 1 of Exhibit No.__(RRP-5) shows the location of the plant in relation to Avista's electric service area. The plant is physically interconnected to the 500 kilovolt (kV) transmission system of the Bonneville Power Administration (BPA), and is approximately 18.5 miles west of the Pacific Gas Transmission (PGT) pipeline, near the Washington/Oregon border. Although the resource is located to the southwest of Avista's service area, electronic equipment has been installed at the plant so that the resource is electrically located within the control area operated by Avista Utilities.

The Coyote Springs site was originally developed by Portland General Electric (PGE), and was designed for two gas-fired combined-cycle units. Coyote Springs 1 (CS1), the first unit, was completed in 1995, and is owned and operated by PGE. With Avista's recent acquisition of Mirant's 50% share of CS2, Avista now owns 100% of the second unit. The CS1 and CS2 buildings are connected physically, as shown in the photograph on page 2 of Exhibit No.__(RRP-5). For efficiency purposes, CS2 was designed to be operated from the same control center as CS1, and Avista has an operating agreement with PGE for PGE to operate CS2 for Avista.

Q. How did Avista originally acquire Coyote Spring 2?

A. In 2000, 100% of the CS2 project was selected by Avista as the resource to meet Avista's long-term resource needs. Avista's update to the IRP in 2000 showed a long-term resource need for approximately 300 MW of capacity and energy, and the need for a base-load resource in 2004. Excerpts from the updated IRP in 2000 are attached as Exhibit No.__(RRP-6). In August 2000 Avista issued an "all-resource" RFP requesting offers for all resource types, including supply-side and demand-side resources. The RFP was developed with input from the Washington and Idaho Commission staffs, and other parties outside the Company.

Avista received 32 proposals from 23 bidders in response to the RFP, for a total of 2,700 MW of resources. The proposals included a variety of resources including energy efficiency and supply-side projects, including renewable resources.

Supply-side and demand-side resources were subjected to an evaluation and screening process developed in advance of opening the bids. The evaluation process included both price and non-price factors. Analyses and results of the evaluations were shared with Washington and Idaho Commission staffs.

Q. Was Avista's RFP process reviewed by an independent third party?

A. Yes. Avista retained R.W. Beck to conduct a third-party review and evaluation of the Company's dispatch and economic modeling analyses. The R.W. Beck report included the following assessment of the Company's analytical approach and methodology:

> Based on our review, R.W. Beck believes the approach taken by Avista in its analysis of the alternative resource proposals provides a fair comparison of the resource options includ[ed] in the bid proposals or the self-build option. We believe that comparing Avista's total system cost with and without each of the resource options, and the net project benefit of each proposed resource, is a reasonable way to determine which options are the most financially and economically viable for Avista.
>
> Avista has used an adequate level of care to include the necessary assumptions and methodology in both the Prosym™ modeling of the bids and in the economic analysis spreadsheets. R.W. Beck did not find any material deficiencies (such as miscalculation of formulas or omission of essential data) in either the input files or the electronic spread sheet analyses.

At the conclusion of the RFP process in December 2000, Avista selected 100% of the CS2 project as the preferred supply-side resource option. Construction of the CS2 project began in January 2001.

Q. Why did Avista subsequently sell 50% of CS2 to Mirant in the Fall of 2001?

A. During 2001 Avista experienced the worst hydroelectric generation conditions on record, coupled with unprecedented high wholesale market prices. The combination of low water conditions and high market prices caused the Company to incur significant expenditures for replacement power, which created serious financial challenges. Avista was not able to secure project financing for the CS2 project, and was unable to otherwise finance the project on its own under reasonable terms.

After considering and evaluating the available options, Avista entered into an agreement with the Mirant Corporation. The December 2001 agreement transferred half-ownership in the CS2 project to Mirant, in return for payment of one-half of the capital costs (both prior and prospective) of the plant.

Q. When did CS2 begin commercial operation?

A. Commercial operation of the CS2 project was originally scheduled for June 2002. The commercial operation of the project was ultimately delayed until July 1, 2003, because of the Enron bankruptcy, and problems with the generator step-up transformer.[3]

Excluding the period when CS2 was down with transformer problems, the Project has operated with a high equivalent availability factor of 94.3% through December 31, 2004 and a forced-outage rate of 1.667%. In addition, recent tests in December 2004 showed a favorable heat rate for the CS2 project of 6,814 Btu/kWh.

In addition, Avista purchased a spare generator step-up transformer from a different manufacturer. The spare transformer is at the CS2 site and is available for use.

Q. How did Avista come to re-acquire the second half of Coyote Springs 2?

A. In April 2004, financial difficulties faced by Mirant prompted it to offer to Avista the opportunity to reacquire the second half of CS2. On July 14, 2003, Mirant filed for Chapter 11 bankruptcy protection, citing in their press release "strain on our liquidity and [a lack of timely support by creditors] threatened the feasibility of our business plan ...[and with] uncertainty about the timing of the recovery in power prices and a slow economic recovery in the U.S. ...it became clear that a comprehensive financial reorganization was the best approach for our stakeholders."

In April 2004, representatives of Mirant-Oregon LLC approached Avista to indicate that its interest in the CS2 project was for sale.[4] On July 12, 2004 the Company and Mirant-Oregon

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[3] The circumstances and costs associated with the delay in the commercial operation of CS2 were addressed in detail in the Company's 2003 ERM filing in Docket No. UE-030751

[4] Mirant-Oregon, LLC, a subsidiary of Mirant, is the actual half-owner of CS2. As of this filing data, the Mirant-Oregon, LLC subsidiary of Mirant Corporation has not itself filed for bankruptcy protection.

LLC executed a non-binding Letter of Intent (LOI) for Avista to purchase the plant. A copy of the LOI is provided as Exhibit No.__(RRP-7). The Purchase & Sale Agreement for Avista to purchase the second half of the plant was signed on October 13, 2004. A copy of the Purchase & Sale Agreement is provided as Exhibit No.__(RRP-8). The cost of acquiring Mirant's share of CS2 was very attractive: Avista paid $62.5 million, which translates to $439/kW of installed capacity. The $62.5 million purchase price represents approximately 58% of the original investment for this portion of the CS2 project. Simply put, this provided a very attractive opportunity to acquire a needed resource at a very competitive price.

Q. What approvals were necessary in order for Avista to acquire Mirant's share of CS2?

A. A competitive auction process was included as one of the conditions in Mirant's bankruptcy proceedings. After completion of the auction process, the judge involved in Mirant's bankruptcy process approved Avista's $62.5 million bid on December 15, 2004.

The Company was also required to obtain approvals from the State of Oregon Energy Facility Siting Council (OEFSC). Avista received approval from the OEFSC on December 2, 2004. The Company's FERC Section 203 Request to Transfer Jurisdictional Asset was approved by FERC on December 30, 2004.

On January 19, 2005 Avista executed the final documents to purchase Mirant's 50% ownership interest in the Coyote Springs 2 generating plant. Avista assumed ownership and began operating the second half of CS2 at 12:01 a.m. January 20, 2005.

Q. Are customers currently benefiting from the second half of CS2?

A. Yes. On January 20, 2005, Avista took ownership of the second half of CS2, and is now owner of 100% of the project. Because of expected poor hydro conditions in 2005, the ERM deadband will be exceeded and 90% of the margins realized from operation of the second half of CS2 will be credited to customers through the ERM process currently in place in Washington. However, until the second half of CS2 is included in rate base, Avista incurs the costs associated with investment in the plant and its operation expenses; neither of which are recovered through the ERM mechanism. Therefore, a mismatch exists between those receiving the benefits vs. those incurring certain expenses associated with the second half of CS2 until the Commission approves the inclusion of the remaining share of CS2 in base rates.

V. ASSESSMENT OF RESOURCE NEED RELATED TO MIRANT'S SHARE OF CS2

Q. Is the acquisition of the second half of CS2 consistent with Avista's Integrated Resource Plan?

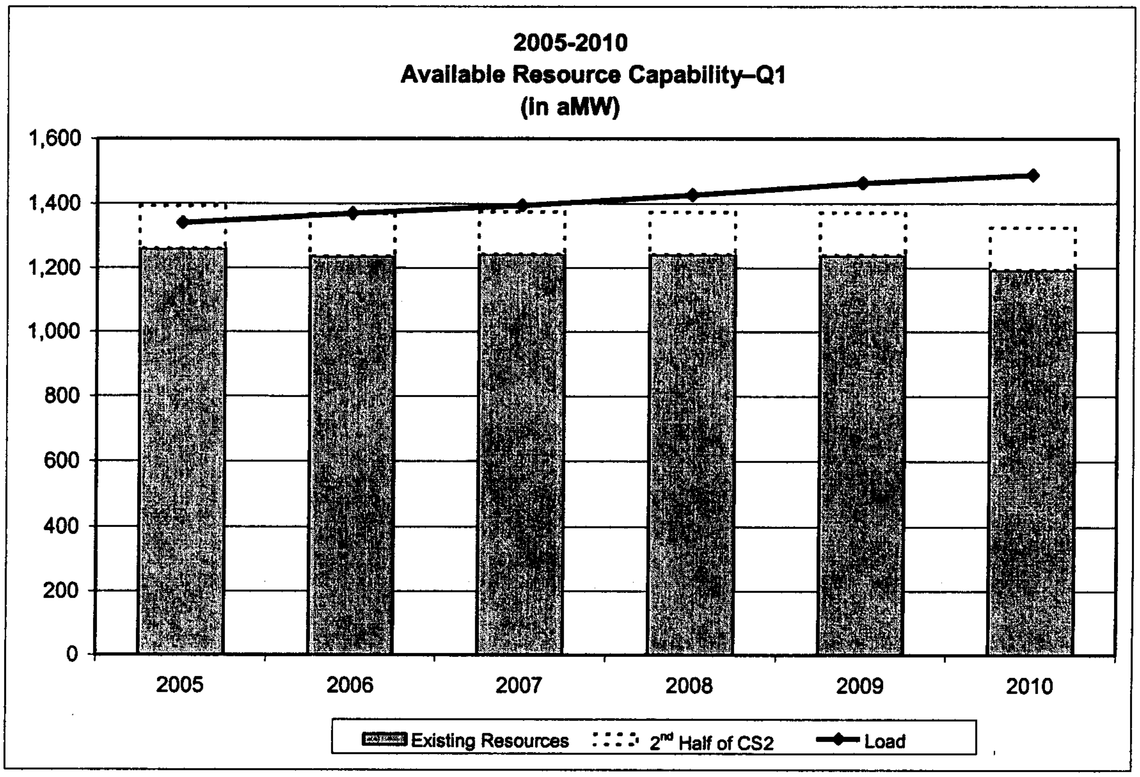
A. Yes. Avista's most recent IRP (April 2003) identified a Preferred Resource Strategy (Resource Strategy) including a mix of wind, coal, conservation, and natural gas-fired resources. The report focused on supply diversity and the need to reduce both future costs and price volatility. In total, the need for new resource additions through 2013 totaled more than 400 aMW. As explained earlier, in addition to the acquisition of the second half of CS2, Avista has added a variety of resources to its portfolio in recent years including 35 MW of wind capability, small generation contracts, market purchases, DSM, and hydroelectric upgrades.

The natural gas-fired combined-cycle component of the 2003 IRP Resource Strategy equaled 149 aMW. The opportunity to acquire the remaining half of CS2, at 140 MW, is consistent with the 2003 IRP long-term Resource Strategy. Excerpted pages from the 2003 IRP, which show the natural gas-fired combined cycle component of the Resource Strategy, are attached in Exhibit No.__(RRP-9). A complete copy of the 2003 IRP has been provided in the workpapers of this filing.

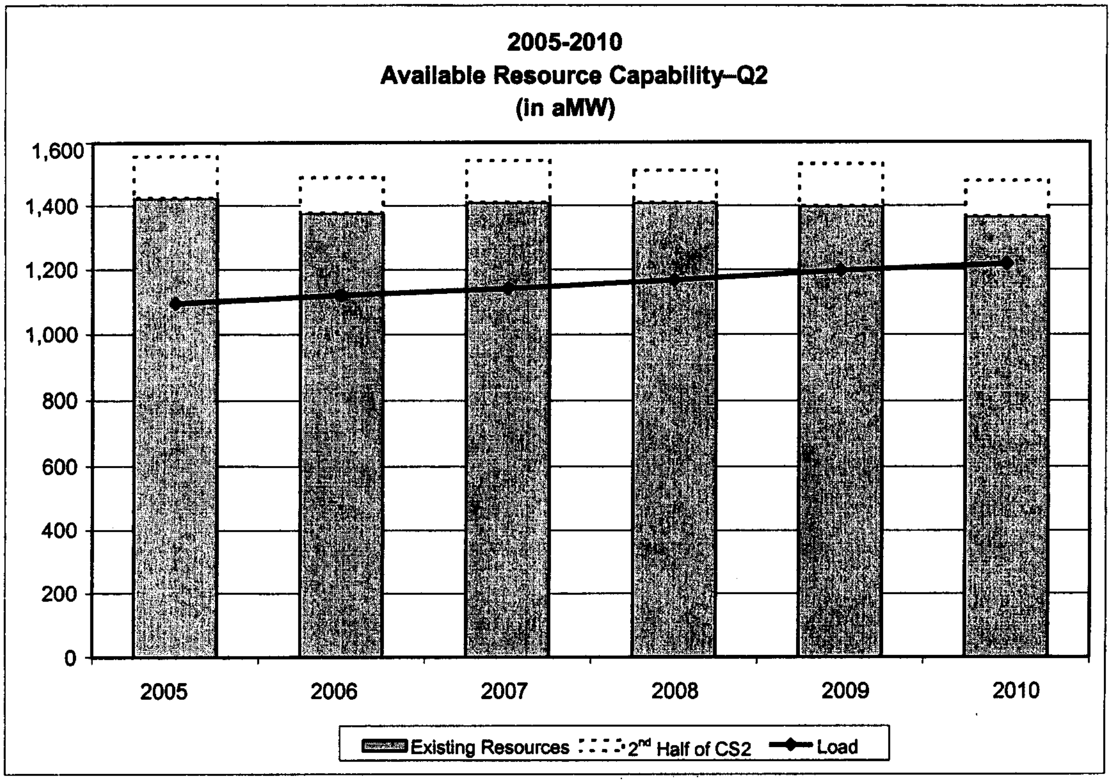
Q. Did Avista's load and resource position show a resource need at the time of the acquisition of the second half of CS2?

A. Yes. The Company's loads and resources (L&R) positions are updated periodically to reflect various resource additions, deletions, and modifications, as well as changes in Avista's load obligations. The Company's L&R at the time the Company entered into the agreement to acquire Mirant's share of CS2, showed energy resource deficiencies in the 1st, 3rd and 4th quarters of 2005 and future years, absent the second half of CS2. Excerpts from the Company's August/September 2004 loads and resources position are included in Exhibit No.__(RRP-10). (The entire reports have been included in workpapers.) Although the addition of the second half of CS2 adds to Avista's surplus energy during the 2nd quarter, under many operating conditions a natural gas-fired combined cycle project such as CS2 would be displaced by lower priced power during the spring runoff period in the 2nd quarter, and would not be running. The second half of CS2, however, is a needed addition to Avista's resource base by covering deficits in Q1, Q3, and Q4.

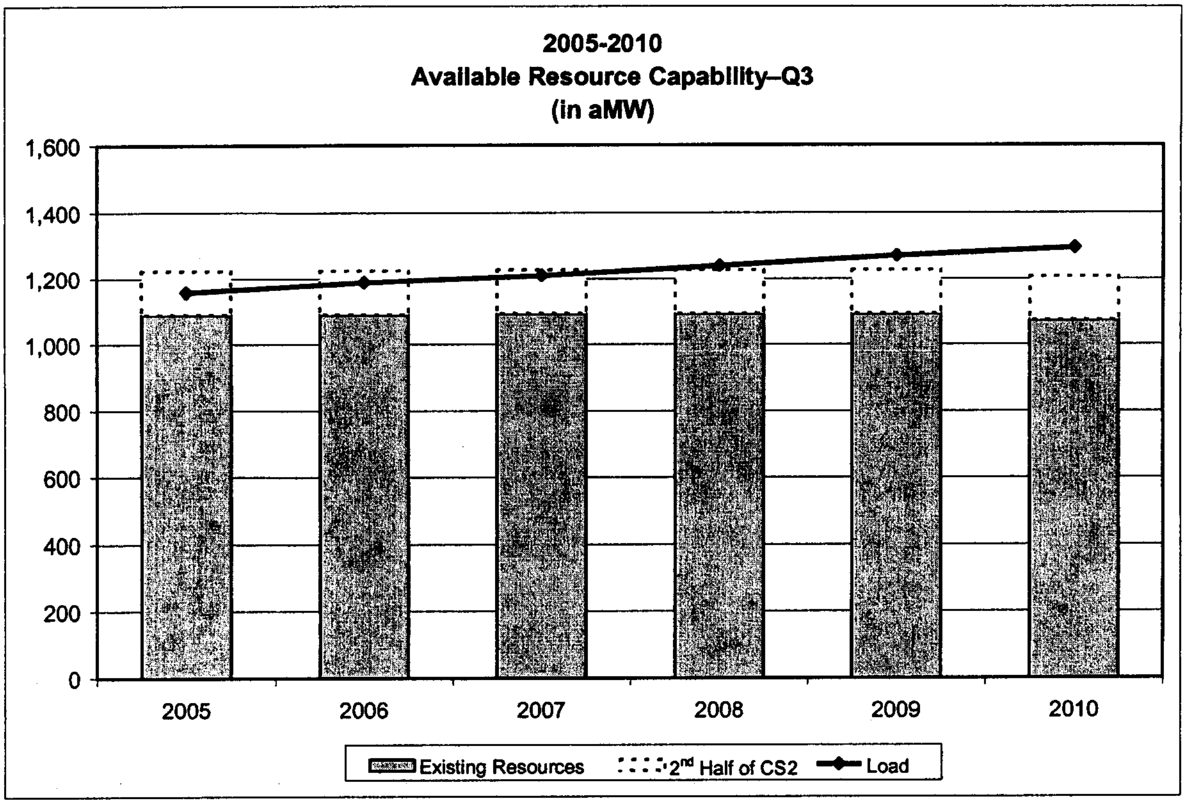
The following chart shows the Company's August/September L&R positions for the 1st quarter of each year from 2005 through 2010. The chart shows that Avista's existing resources for the 1st quarter of each year, for planning purposes, are not sufficient to cover the Company's load. As the loads continue to grow over time, they exceed available resources including the second half of CS2.

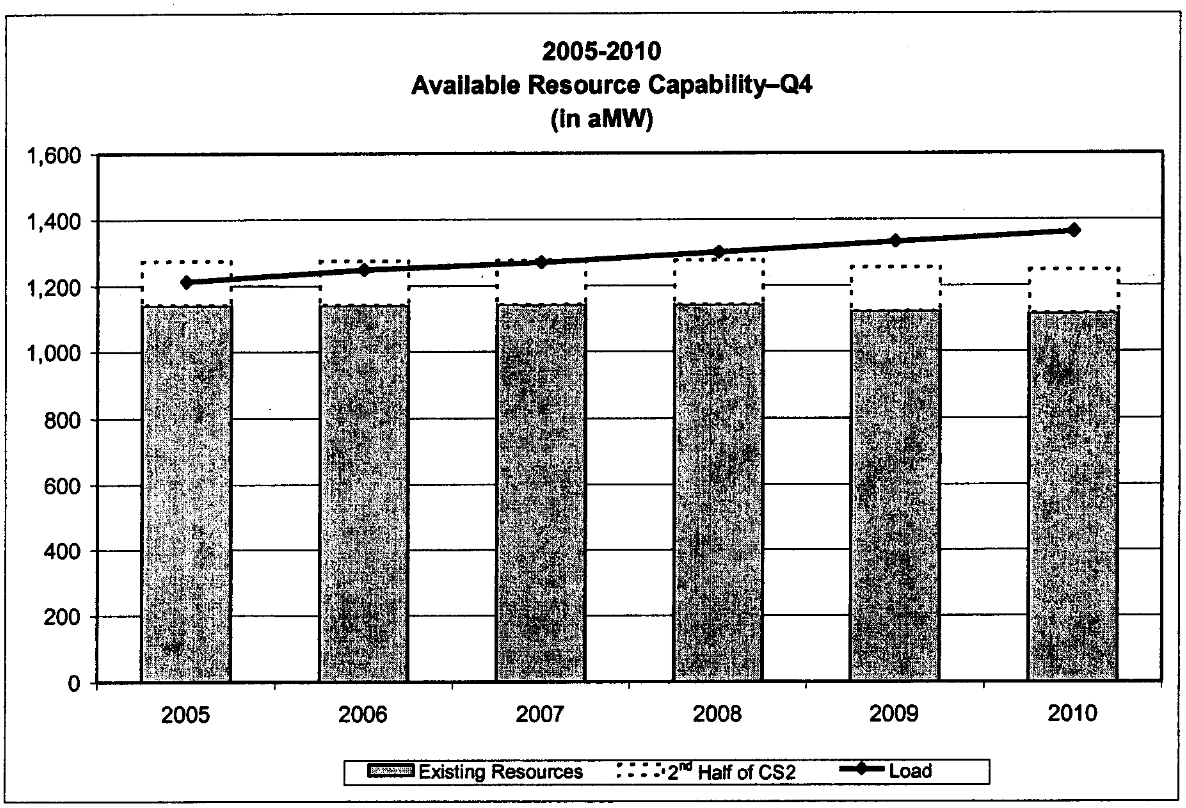


The next chart shows the Company's L&R positions for the 2nd quarter of each year from 2005 through 2010. The chart shows a surplus on Avista's system for the 2nd quarter, both with and without the second half of CS2. This is caused by the increased availability of hydroelectric generation in the 2nd quarter, as well as the fact that loads are generally lower given the relatively mild temperatures in the same period.

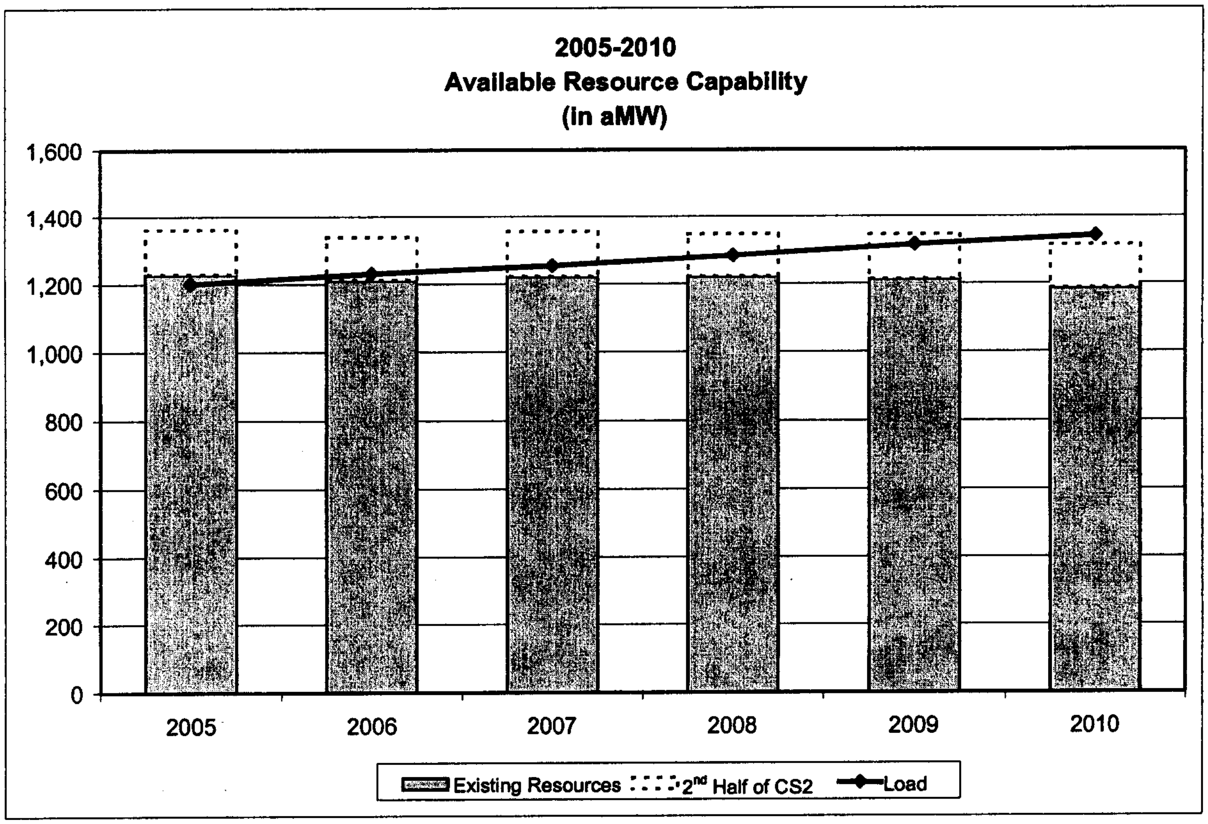


The following two charts show the Company's L&R positions for the 3rd and 4th quarters of each year from 2005 through 2010. The charts show that Avista's existing resources for the 3rd and 4th quarters of each year, for planning purposes, are not sufficient to cover the Company's load. Again, as the loads continue to grow over time, they exceed available resources including the second half of CS2.


2005-2010
Available Resource Capability–Q3
(in aMW)
1,600
1,400
1,200
1,000
800
600
400
200
0
2005
2006
2007
2008
2009
2010
Existing Resources
2nd Half of CS2
Load


2005-2010
Available Resource Capability–Q4
(in aMW)
1,600
1,400
1,200
1,000
800
600
400
200
0
2005
2006
2007
2008
2009
2010
Existing Resources
2nd Half of CS2
Load

The final chart below shows the Company's L&R positions for each calendar year 2005 through 2010. In developing this chart, the surpluses in the 2^{nd} quarter of each year are averaged with the deficiencies in the 1^{st}, 3^{rd} and 4^{th} quarters. The 2^{nd} quarter surpluses "mask" the deficiencies in the other three quarters.



These charts illustrate how the addition of the second half of CS2 will fit very well in Avista's resource base by covering deficiencies in the 1^{st}, 3^{rd} and 4^{th} quarters of each year. The addition of the second half of CS2 therefore meets important resource needs in three quarters of each year beginning in 2005.

VI. ECONOMIC ANALYSES AND PURCHASE PRICE FOR MIRANT'S SHARE OF CS2

Q. What economic analyses did the Company conduct prior to the purchase of the second half of CS2?

A. With regard to the economic analyses underlying the purchase price of $62.5 million, the Company performed two separate evaluations of Mirant's half of CS2: one in May 2004 and a second in September 2004. The first evaluation, completed on May 7, 2004, was comprised of eight scenarios. The eight scenarios came from four different forward analyses of the marketplace, combined with two transmission scenarios.[5] The transmission scenarios examined, first, the effect of the procurement of firm transmission on a year-around basis and, second, circumstances where the plant would be constrained during the second quarter due to transmission curtailments on the BPA system.[6]

Using the Aurora dispatch model, the Company performed the various scenarios to reflect the potential future value of CS2. The May 2004 Base Case scenario included a combination of forward market prices through 2008, followed by 2003 IRP prices through the end of the 20-year study period, and the assumption that the plant would not be available to serve load or sell into the wholesale marketplace in the second quarter due to transmission constraints as described above.

The Base Case value from the May analysis, which was used by Avista in its negotiations with Mirant, was <u>$68.0 million</u>. The remaining scenarios ranged from $43.1 to $116.9 million. The May Base Case analysis showed an expected net present value ratepayer savings of $7.5

[5] Mirant did not procure firm transmission for its share of CS2. Avista plans to "firm up" transmission for the plant, as explained later in this Testimony.

million over the study period based on the purchase price of $62.5 million. The May 2004 analysis is provided in Exhibit No.__(RRP-11).

Avista continued to perform analyses after signing the non-binding Letter of Intent (LOI) in July 2004. Transmission alternatives were also reviewed. Avista completed its second economic evaluation in September 2004. Six of the original scenarios were revisited, resulting in a Base Case valuation equal to <u>$66.7 million</u>, as compared to the original study estimate of $68.0 million. The September 2004 analysis is provided in Exhibit No.__(RRP-12).

Q. Are there other benefits related to the acquisition?

A. Yes. In addition to the economic value and ability to meet retail load requirements, full ownership of CS2 brings other benefits to the Company and its customers. Full ownership by Avista would improve the Company's ability to economically operate CS2. When Mirant was a partner in the CS2 project, it periodically chose to not run the plant when Avista wanted to. Although the joint operating agreement for CS2 allowed the entity interested in running the plant to take the entire output of CS2, this arrangement did not allow Avista to plan on a forward basis to meet load with the plant. If Avista was already in a balanced load and resource position at the pre-schedule time when Mirant made its decision to not operate, the Company would need to go to the pre-schedule market on a very short timeframe (1-2 hours) to purchase natural gas fuel and to sell surplus power in order to operate CS2. Full ownership will avoid this last-minute decision-making, and enhance the value of CS2 by allowing dispatch decisions to be made days and months ahead of actual operations.

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[6] Firm transmission is currently not available at the CS2 locations on a long-term <u>annual</u> basis primarily due to peak hydroelectric generation during the second quarter.

Further, decisions can be made faster in the event of unexpected plant de-rating or outages, or in the event capital upgrades or replacements are necessary. While each of these items is not in and of itself greatly significant, together they add up to a meaningful improvement in the ownership and operation of the CS2 project.

Q. How does the cost of the second half of CS2 compare with other combined cycle combustion turbine plants?

A. As part of its review of the CS2 second half acquisition, Avista looked at the costs of other comparable natural gas-fired combined cycle projects. While few combined cycle plants have changed hands in the West, documentation on new plant costs are readily available. The information in the table below consists of data regarding estimates of new combined cycle construction costs and available information on the recent acquisition of the Fredrickson project by Puget Sound Energy. The CS2 purchase price of $62.5 million, or $439 per kW of installed capacity, is significantly below the cost of comparable projects, including prices for larger projects with a different configuration that tend to have a lower cost per-kW due to economies of scale.[7]

[7] Some larger gas-fired projects are configured with two combustion turbines "attached" to one heat recovery steam generator (2x1 combined cycle project). 1x1 plants have one combustion turbine attached to a heat recovery steam generator. The 2x1 configuration generally results in a lower cost per installed capacity due to economies of scale.

Comparison Data for Combined Cycle Plant Costs in the Northwest

Source	Installed Cost ($/kW)	Notes
2nd Half CS2 Price	**$439**	**1x1 configuration**
AVA 2003 IRP	$757	1x1 configuration
NWPCC Estimate	$606	2x1 configuration
PSE Frederickson - Low	$558	WSJ article
PSE Frederickson - High	$590	PSE press release
PGE Port Westward - Low	$590	2x1 configuration
PGE Port Westward - High	$670	1x1 configuration
Idaho Power Draft '04 IRP	$617	2x1 configuration
IPUC – Avoided Cost[8]	$736	Order 26017, 1x1
PacifiCorp 2003 IRP	$670	Unit type unknown
PSE 2003 IRP	$661	2x1 configuration

Q. Did the Company obtain an independent review of the second half of CS2 acquisition?

A. Yes. The Company hired an external consultant to provide an independent assessment that could be used by management in its decision-making. This assessment was designed to take a fresh look at the valuation analysis, through independent eyes. Accordingly, Avista hired Navigant Consulting, Incorporated (NCI) to complete three tasks prior to the Company proceeding with the transaction: 1) review Avista's overall methodology and analyses; 2) develop an independent valuation of Mirant's share of CS2, to include base, low, and high scenarios; and 3) compare the CS2 price to comparable power plant transactions occurring in the Northwest and Western United States Region. The Navigant report is attached to this filing as Exhibit No.__(RRP-13).

[8] Surrogate combined cycle combustion turbine project cost.

Navigant developed an independent assessment of the future value of Mirant's share of CS2. The consultant modeled low, base, and high valuation cases using a Prosym™ model. Navigant found a base case value of $67.2 million for Mirant's interest in CS2, which is very close to the Avista September 2004 results of $66.7 million.

The Navigant evaluation indicated that the acquisition of Mirant's share of CS2 for utility customers was reasonable. In its conclusions, Navigant stated:

> Avista's base case valuation ... for the remaining 50% of Coyote Springs II reflects a reasonable valuation for this facility and compares favorably to the other transactions consummated in the Pacific Northwest which have averaged $561/kW. (Page 15 of the Navigant report) (emphasis added)

Navigant went further to explain:

> NCI's independent analyses and base case valuation results reflect a value of $67.2 million ($472/kW) for 50% of the Coyote Springs II facility... Therefore, based upon our review of the Avista analyses, our own independent analyses, and comparable generation transactions consummated in the market, NCI believes that Avista's negotiated purchase price of $62.5 million for 50% of the Coyote Springs II facility is reasonable. The negotiated purchase price is below the Avista and NCI base case valuation results of $66.7 million and $67.2 million respectively. (Page 15 of the Navigant report) (emphasis added).

Q. How has Avista addressed the transmission needs of the second half of Coyote Springs 2?

A. Avista included in its analyses the cost of BPA long-term firm transmission to move power from the second half of the CS2 project to its system. BPA currently indicates that no additional annual long-term firm transmission capability is available to move more power from CS2 to the Company's system, due to transmission constraints during the spring hydroelectric runoff period. Transmission is generally available, however, during the 1st, 3rd and 4th quarters of the year when Avista needs the generation.

Through acquisition of the second half of CS2, Avista has the opportunity to acquire Mirant's higher position in the BPA queue for long-term firm transmission requests. Avista also made its own long-term firm transmission request to BPA for the CS2 transaction. Avista may acquire firm long-term BPA transmission through either of those processes. Avista is also participating in the 2005 BPA open season for transmission upgrades to the John Day – McNary 500 kV transmission line that will, if agreements are reached, provide adequate long-term firm transmission from the CS2 project to its system. The BPA open season would replace the transmission queue requests.

In the near-term Avista plans to contract with third parties for short-term BPA transmission, for buy-sell arrangements, and/or for energy exchange arrangements. These opportunities will allow the same energy transfer that would occur with a firm BPA transmission purchase. Preliminary discussions with BPA indicate that adequate short-term transmission capacity will be available for Q1, Q3, and Q4. In the Company's experience, non-firm transmission has very seldom been curtailed by BPA. Avista's Base Case valuation of the CS2 transaction factors in costs relating to transmission and recognizes that BPA may have a constraint that restricts the Company's ability to transfer additional CS2 power during the second quarter of each year. This conservative view of Q2 transmission availability over the life of the project has only a modest impact on the value of CS2. The plant produces a small portion of its economic value during the second quarter.

Q. What arrangements have been made to transport natural gas to the plant?.

A. Natural gas transportation for CS2 includes three components: AECO to Kingsgate; Kingsgate to the Coyote Springs Lateral; and the Coyote Springs Lateral. At full output, the 280 MW CS2 project (100% share) consumes approximately 43,000 decatherms (dth) per day.

For the AECO to Kingsgate portion, Avista holds 34,138 dth per day from the TransCanada Pipeline's 2003 expansion project, through October 2028. Avista Utilities also had available an additional 10,268 dth of capacity for its retail natural gas distribution business that has been reassigned through October 2008. This results in total delivery to CS2 equal to 44,406 dth per day.

Avista holds 16,500 dth per day through October 2028 on the Kingsgate to Coyote Springs lateral. This capacity was obtained as part of Gas Transportation Northwest's (GTN) 2003 expansion. Avista also holds 10,000 dth per day on GTN that has been reassigned from its retail natural gas distribution business, resulting in total delivery capability of 26,500 dth per day. Effective on January 20, 2005, the Company acquired an additional 16,500 dth per day, through October 2028, bringing the total capacity on this GTN leg to 43,000 dth per day.

Avista and Mirant each held contracts for 28,626 dth per day through October 2015 on the Coyote Springs Lateral. Mirant agreed as part of the CS2 transaction to transfer its existing rights on the lateral to Avista as part of the sale, giving Avista a total of 57,252 dth per day delivery capability on the lateral.

Q. Can you summarize why the acquisition of the second half of Coyote Springs 2 was prudent for Avista?

A. Avista had immediate needs for resources in each of quarters 1, 3,and 4 beginning in 2005 and increasing into the future. As an efficient combined cycle combustion turbine resource which produces most of its margin benefit in 1st, 3rd and 4th quarters, the acquisition of the second half of CS2 is a good fit for meeting Avista's resource need now and into the future. The second half of CS2 is also a cost-effective resource acquisition as illustrated by Avista's economic analysis, the independent economic analysis of Navigant Consulting Inc., and by comparison against comparable generation transactions consummated in the market.

VII. PROPOSAL TO ELIMINATE ERM DEADBAND

Q. Would you please begin by describing the basic features of the ERM as it exists today, and the change that the Company is proposing to make?

A. Yes. The ERM (Energy Recovery Mechanism) was implemented in Washington in July 2002, and was designed to provide a means for recovering power supply costs that were prudently incurred, but beyond the reasonable control of the Company. On a monthly basis the Company's actual power supply costs are compared with the power supply costs included in base retail rates to determine the monthly change in costs. Under the ERM, Avista absorbs or retains the first $9.0 million of cost differences during a calendar year, and 90% of the excess over the $9.0 million is deferred for future rebate or surcharge to customers.

The costs included in the ERM are purchased power expenses and thermal fuel costs. Wholesale sales revenues are also included as a credit against the purchased power and fuel costs. Although there are a number of factors that cause the actual power supply costs to be different that those included in base retail rates, the primary drivers, by far, are hydroelectric generation conditions, natural gas prices for thermal generation, and wholesale electric market prices. All of these factors are substantially beyond the control of the Company and are impossible to predict with any meaningful degree of accuracy.

The $9.0 million to be absorbed or retained by the Company each year is referred to as the "Company band" or "dead band." In this filing Avista is proposing to eliminate the dead band. The Company is proposing that the 90%/10% sharing of cost differences remain in place.

Each year the Company makes a filing, on or before April 1st, to provide the Commission and interested parties an opportunity to review the prudence of and audit the ERM deferral entries for the prior calendar year. In addition, the Company submits monthly reports to the Commission and interested parties explaining the deferrals, along with supporting workpapers. The Company is proposing no changes to these filing and reporting requirements.

Q. Why has the Company proposed to eliminate the deadband?

A. The deadband was developed in conjunction with a settlement related to some fixed-price contracts that were entered into by Avista during the energy crisis of 2001 to provide natural gas for thermal generation. At the time of the settlement in May 2002, the forward price of natural gas was lower than the price in the contracts, and it was understood that, absent other changes in power supply-related costs, the Company would absorb a portion of the cost of the contracts through the deadband. The last remaining natural gas contract terminated on October 31, 2004. Therefore, this element related to the deadband no longer exists.

As explained earlier, the changes in costs included in the ERM are driven primarily by factors that are beyond the Company's control. As a hydro-based utility, Avista serves approximately 50% of its customers' load requirements with hydroelectric generation. Because of this heavy reliance on hydro, it takes only a 7% change in hydroelectric generation within the year to fill the $9.0 million deadband.[9] That is, a 7% change in hydro, up or down, would cause the Company to either absorb $9.0 million or benefit by $9.0 million. In either event, the Company would either absorb a substantial cost or receive a substantial benefit for something over which it had no control.

In addition, Avista also relies on significant natural gas purchases to supply fuel for its natural gas fired thermal units. It takes approximately 43,000 dekatherms (dth) per day to fuel the Coyote Springs 2 project at full load. The forward market price of natural gas, in recent months, has been approximately $6.00/dth. The future price of natural gas could easily be $7.00/dth or $5.00/dth, given the volatility of pricing that the industry is experiencing. A $1.00/dth change in the cost of natural gas to run Coyote would equal approximately $15.7 million on an annual basis, or $10.2 million for the Washington jurisdiction, which would exceed the $9.0 million deadband. Again, a change in natural gas prices of this nature would cause the Company to benefit by $9.0 million or absorb $9.0 million due to something over which it has essentially no control.

Q. How are changes in natural gas costs handled for natural gas retail distribution companies in the State of Washington?

A. The WUTC has approved tracking mechanisms for natural gas distribution companies, including Avista, that provide for a dollar-for-dollar recovery of the changes in natural gas costs to serve its customers. Each month actual gas costs are compared with the gas costs collected from customers in retail rates, and the difference is deferred for later rebate or surcharge to customers. The dollar-for-dollar tracking of costs is due, in part, to recognition that

[9] 510 aMW of hydroelectric generation under normal conditions times 7% = 36 aMW, times 8760 hours, times

the future market price of natural gas is not predictable and is beyond the control of the utility. Avista currently has similar dollar-for-dollar tracking mechanisms in place in Idaho and Oregon for its retail natural gas distribution operations.

In a like manner, future natural gas prices for thermal generation are unpredictable and beyond the utility's control, and in a similar manner, future streamflow for hydroelectric generation is unpredictable and uncontrollable. Although we believe it would be reasonable and appropriate to track the changes in power supply costs on a dollar-for-dollar basis through the ERM, the Company is proposing elimination of the deadband, but not the elimination of the 90%/10% sharing at this time.

Q. What as been the Company's experience with the deadband since its inception?

A. Since the ERM was implemented in July 2002, the Company has absorbed $22.5 million in losses through the deadband. An additional $5.7 million was absorbed by the Company through application of the 90%/10% sharing. For 2005, based on current projections, the Company will again absorb the entire $9 million deadband, given hydroelectric generation conditions and natural gas pricing.

Q. Does Avista's Power Cost Adjustment (PCA) mechanism for its electric operations in the State of Idaho include a deadband.

A. No. The PCA in Idaho for Avista's electric utility business is almost identical to the ERM in design, with the exception of the deadband. In the PCA, 90% of the changes in power supply costs on a monthly basis are deferred for later rebate or surcharge to customers.

$47/MWh, times 65.16% Washington jurisdictional share = $9.6 million

Q. Are power supply and fuel cost tracking mechanisms common in other state jurisdictions?

A. Yes, power supply and fuel cost tracking mechanisms are very common in other state jurisdictions, especially in states that have not engaged in some form of retail access. In March 2005, Banc of America Securities (BOAS) published a report entitled "The Kaleidoscope of Power – Regulation in Focus." In that report, BOAS summarized the "Adjustment Clauses" that are currently in place for the respective state jurisdictions. Excerpts from the report for some of the state jurisdictions are as follows:

Alabama	**Adjustment clauses are permitted (after a hearing) via quarterly adjustments, up or down, and are based on forecast costs with true-ups for past deviations from forecast.**
Arkansas	**Fuel and the energy component of purchased power costs are adjusted annually through the Energy Cost Recovery Rider based on a combination of historical and forecast information. Interim adjustments are permitted in the event of significant deviations from actual experience.**
California	**Annual review through the Energy Resource Recovery Account, with forecast costs early in the year and a prudence review in second half.**
Georgia	**Adjustment clauses are permitted, based on projected three-month fuel and energy-related purchased power costs and past over or under collections. The GA PSC must rule on the filing within 90 days of the filing or the change is deemed approved.**
Hawaii	**Hawaiian electric utilities have an energy cost adjustment clause that does not require prior HI PUC approval of changes once the initial clause is established. The HI PUC staff periodically audits the plan.**
Indiana	**Permitted by law. Recovers fuel and purchased power expenses. Not more than one filing for recovery every three months.**

Mississippi	**The fuel and the energy portion of purchased power costs, plus emissions allowance costs, are forecast for the next 12 months and then trued-up in the following 12-month period.**
Nevada	**Utilities have two options. They can file for an increase in fuel and purchase power costs as often as monthly, or they can use the deferral method and true-up costs annually, with any deferred amounts recovered over a period of up to three years. Both electric utilities currently use the latter method.**
North Dakota	**Fuel cost adjustments are permitted on a monthly basis.**
Oklahoma	**Fuel and purchased power adjustment clauses are permitted, provided that the OCC reviews and approves the changes prior to their going into effect. Adjustment clause relies on actual fuel costs, not estimates.**
Washington	**Fuel and purchased cost adjustments are permitted, and Puget and Avista have adjustment clauses in place. The current plans subject the utility to the risk/reward of under/over collection of a portion of the change in expected costs before costs are passed on to customers. <u>This "dead band" approach has subjected the utility to greater earnings volatility than a simple recovery mechanism</u>. (underscore added)**

It is important to note that the investment community, in this case Banc of America Securities, recognizes the increased exposure to Avista from the dead band, as compared to other tracking mechanisms.

Furthermore, as indicated by the above quotes from the report, some of the tracking mechanisms allow the use of forecasted information, or monthly or quarterly price changes, which provides more timely recovery of costs, and a price signal to customers on the changes in costs.

Q. Would elimination of the ERM dead band eliminate the majority of the risks faced by Avista?

A. No. The utility faces many other risks and challenges apart from the variability of costs associated with hydroelectric generation and wholesale electric and natural gas prices. Avista's retail revenue can change substantially from changes in weather conditions and other factors affecting customer usage. New investment related to customer growth and equipment replacement is more expensive, in general, than the equipment installed many years ago, resulting in increased costs that are not recovered until a future rate case. Avista, and others in the industry, are continuing to experience increased legal costs, audit fees, insurance and other costs as part of the fallout related to the energy crisis of 2000/2001, the September 11, 2001 act of terrorism, and compliance with new accounting and reporting rules such as Sarbanes/Oxley.

Furthermore, base retail rates in Washington continue to be based on a historical test period, where forecasted information, future estimates, and attrition adjustments, that recognize increases in certain costs over time, are not allowed. There is a constant challenge each year to manage costs within a revenue requirement that is based, in large part, on historic information that may not reflect future conditions.

Q. If the deadband were to be eliminated, would Avista continue to have an incentive to manage its power supply costs to the benefit of customers?

A. Yes. There would continue to be a 90%/10% sharing of all changes in power supply costs under the ERM. Therefore, to the extent the Company has control over certain cost items, it has the incentive to make the most economic choice for the Company and its customers.

In addition, the Commission Staff and interested parties perform audits of the Company's performance in management of power supply costs as part of the annual ERM filings, in order to determine whether costs are prudent and suitable for recovery. This oversight process is an additional incentive for the Company to make prudent choices as it manages its power supply costs.

Q. Please summarize the Company's request related to the ERM deadband.

A. Avista requests that the Commission eliminate the dead band from the current ERM mechanism. Absent the deadband, 90% of the changes in power supply costs each month, positive or negative, would be deferred for future rebate or surcharge to customers. No other changes to the ERM are being proposed at this time.

Absorbing the deadband places the Company in the position of having, among other things, reduced cash flow, increased financing costs, and reduced interest coverage ratios, which makes it all the more difficult for Avista regain its financial health and regain investment grade credit ratings. The dead band should be eliminated at least until Avista receives and maintains a stable investment grade credit rating.

VIII. WARTSILA AMORTIZATION

Q. Would you please explain the proposed deferral and amortization of capital costs associated with the Wartsila small generation units being proposed in this case?

A. Yes. The Company is proposing deferred accounting treatment for the cost of two 4 MW reciprocating engine generators that were originally planned to be installed at Boulder Park. Boulder Park is a natural gas-fired, small generation project completed in 2002. The initial economic analysis of the Boulder Park site showed that installation of 8 Wartsila generating units would be cost-effective. Subsequent air emission modeling limited the Boulder Park Project to 6 units instead of the 8 units originally planned. Analysis and plans were then developed to install the remaining two units at a Spokane Industrial Park (SIP) site. The SIP Project was cancelled later in 2001 due to the decline in energy prices. Since that time, the value of the two generating units has dropped.

The Company invested approximately $3.65 million in the two Wartsila units. The costs have been recorded in Account 183, Preliminary Survey and Investigation Charges. The Company has placed the generating units on the market for sale. It is currently expected that sales proceeds will amount to approximately $1.3 million, leaving approximately $2.35 million of unrecovered costs on a system basis. Washington's share would be 65.16% of the unrecovered costs, or approximately $1,531,000.

The Company is proposing to amortize, and recover, the expected level of unrecovered costs over a 5-year period with the unamortized balance being excluded from rate base. An adjustment is included in Mr. Falkner's exhibit that reflects the 5-year amortization of the expected level of unrecovered costs of the two Wartsila small generation units.

IX. KETTLE FALLS PRODUCTION TAX CREDIT

Q. Would you please explain the Production Tax Credit Adjustment being proposed in this case?

A. Yes. As a result of the American's Job Creation Act of 2004 (Act) the Company will receive a production tax credit as a reduction to its Federal income tax expense. The production tax credit is related to generation at the Kettle Falls wood waste generating plant, which qualifies as an open-loop[10] biomass project under the Act. The Company is eligible for the credit for five years beginning with the 2005 tax year. A 1.8-cent per kWh production credit is reduced by 50% for open-loop biomass. The resulting 0.9-cent per kWh credit is applied to generation at the Kettle Falls plant. A factor of 95.24% is then applied to the credit amount since tax-exempt pollution control bonds were used to finance a portion of the Kettle Falls plant. Based on pro forma Kettle Falls generation for the January 2006 through December 2006 period, the amount of the credit allocated to Washington operations is approximately $1,985,000. The Company is proposing that 50% of the credit, or approximately $922,000 be included as a reduction to Federal income tax expense in this case. Page 1 of Exhibit No. ___ (RRP-14) shows the calculation of the production tax credit amount described above.

Q. Please explain the Company's involvement in obtaining the production tax credit for open-loop biomass facilities.

A. Enactment of the biomass tax credit last year was the successful conclusion of a long effort by a number of parties, including Avista. In 1997, Avista became an active member of a national coalition, USA Biomass, supporting the biomass tax credit. Within the coalition, Avista was responsible for organizing support among the Northwest Congressional delegation. An

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[10] The term "open-loop biomass" means any solid, nonhazardous, cellulosic waste material which is segregated from other waste materials and which is derived from--

(A) any of the following forest-related resources: mill residues, precommercial thinnings, slash, and brush,

(B) solid wood waste materials, including waste pallets, crates, dunnage, manufacturing and construction wood wastes (other than pressure-treated, chemically-treated, or painted wood wastes), and landscape or right-of-way tree trimmings, but not including municipal solid waste (garbage), gas derived from the biodegradation of solid waste, or paper that is commonly recycled, or

(C) agriculture sources, including orchard tree crops, vineyard, grain, legumes, sugar, and other crop by-products or residues.

Avista Government Relations Manager spent a substantial amount of time from 1997 through 2001 working on this effort, including approximately 6-8 trips to Washington, D.C. each year. Following the departure of the Government Affairs Manager from the company in 2001, Avista continued to support the coalition, led by Avista's Director of Government Relations, who spent a significant amount of time building and maintaining support within the Northwest Congressional delegation. Avista also employed the use of an outside Congressional lobbyist and provided financial support to USA Biomass.

Q. Why is the Company proposing a 50%/50% sharing of the production tax credit between customers and shareholders?

A. The production tax credit, to a large degree, resulted from the lobbying efforts of Avista and other parties. Indeed, through Avista's efforts, the Kettle Falls project was included as the only such facility in the Northwest that became eligible for the tax credit. All lobbying costs are excluded for ratemaking purposes. Therefore, it is not unreasonable that a portion of the benefits that resulted from the lobbying efforts also be excluded for ratemaking purposes, under these circumstances.

Q. Are there additional reasons that the Company supports a sharing of the production tax credit?

A. Yes. It is important that this issue be viewed in a broader context. The Kettle Falls generation project has performed well as a reliable and efficient renewable energy resource. There have been capacity gains at the project increasing output from 42 MW to 50 MW. The plant has had an availability factor of 92.16% over the last 15 years. The plant has won several awards, such as the Washington State's *Environmental Excellence* Award, for reducing emissions from burning waste in open wigwam burners, and *Power Magazine's* Energy Conservation Award. The management and operation of this project by Avista has provided significant value to the Company's customers.

Avista worked very hard to achieve the tax credit. As mentioned, Kettle Falls is the only plant in the Pacific Northwest that is eligible for the credit. In these circumstances, it is reasonable and appropriate for the tax credit to be equitably shared on a 50%/50% basis between customers and shareholders.

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

A. Yes it does.