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DAVID J. MEYER
VICE PRESIDENT AND CHIEF COUNSEL OF
REGULATORY & GOVERNMENTAL AFFAIRS
AVISTA CORPORATION
P.O. BOX 3727
1411 EAST MISSION AVENUE
SPOKANE, WASHINGTON 99220-3727
TELEPHONE: (509) 495-4316
FACSIMILE: (509) 495-8851

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION FOR THE AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE TO ELECTRIC AND NATURAL GAS CUSTOMERS IN THE STATE OF IDAHO	CASE NO. AVU-E-10-01 DIRECT TESTIMONY OF CLINT G. KALICH

FOR AVISTA CORPORATION

(ELECTRIC ONLY)

I. INTRODUCTION

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

A. My name is Clint Kalich. I am employed by Avista Corporation at 1411 East Mission Avenue, Spokane, Washington.

Q. In what capacity are you employed?

A. I am the Manager of Resource Planning & Power Supply Analyses, in the Energy Resources Department of Avista Utilities.

Q. Please state your educational background and professional experience.

A. I graduated from Central Washington University in 1991 with a Bachelor of Science Degree in Business Economics. Shortly after graduation, I accepted an analyst position with Economic and Engineering Services, Inc. (now EES Consulting, Inc.), a Northwest management-consulting firm located in Bellevue, Washington. While employed by EES, I worked primarily for municipalities, public utility districts, and cooperatives in the area of electric utility management. My specific areas of focus were economic analyses of new resource development, rate case proceedings involving the Bonneville Power Administration, integrated (least-cost) resource planning, and demand-side management program development.

In late 1995, I left Economic and Engineering Services, Inc. to join Tacoma Power in Tacoma, Washington. I provided key analytical and policy support in the areas of resource development, procurement, and optimization, hydroelectric operations and re-licensing, unbundled power supply rate-making, contract negotiations, and system operations. I helped develop, and ultimately managed, Tacoma Power's industrial market access program serving one-quarter of the company's retail load.

In mid-2000 I joined the Company and accepted my current position assisting in resource analysis, dispatch modeling, resource procurement, integrated resource planning, and rate case proceedings. Much of my career has involved resource dispatch modeling of the nature described in this testimony.

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

A. My testimony will describe the Company's use of the $AURORA_{XMP}$ dispatch model, or "Dispatch Model." I will explain the key assumptions driving the Dispatch Model's market forecast of electricity prices. The discussion includes the variables of natural gas, Western Interconnect loads and resources, and hydroelectric conditions. I will describe how the model dispatches our resources and contracts in a manner that maximizes benefits to customers and tracks their values for use in pro forma calculations. I will then present the modeling results provided to Company witness Mr. Johnson for his power supply pro forma adjustment calculations. Additionally, in support of Company witness Ms. Knox, I detail the Company's demand classification calculations.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring Exhibit 5, Schedules 1 and 2, as well Confidential Schedule 3. Schedule 1 provides a forecast of Company load and resource positions from 2011 through 2020. Schedule 2 is the spreadsheet used to calculate the demand classification. Confidential Schedule 3 provides summary output from the Dispatch Model. All information contained in the exhibit was prepared by me or prepared under my direction.

II. THE DISPATCH MODEL

Q. What model is the Company using to dispatch its portfolio of resources and obligations?

A. The Company uses EPIS, Inc.'s Dispatch Model for determining power supply costs. The model optimizes dispatch of Company-owned resources and contracts in each hour of the pro forma year. The pro forma period is October 1, 2010 through September 30, 2011. It reflects true system operations by evaluating future resource decisions on an hourly basis.

Q. What AURORA version and database is the Company using for this case?

A. The Company is using $AURORA_{XMP}$ version 9.6.1033, and its associated database (North_American_DB_2009-02).

Q. Please briefly describe the Dispatch Model.

A. The Dispatch Model was developed by EPIS, Inc. of Sandpoint, Idaho. It is a fundamentals-based tool containing demand and resource data for the entire Western Interconnect. It employs multi-area, transmission-constrained dispatch logic to simulate real market conditions. Its true economic dispatch captures the dynamics and economics of electricity markets—both short-term (hourly, daily, monthly) and long-term. On an hourly basis, the Dispatch Model develops an available resource stack, sorting resources from lowest to highest cost. It then compares this resource stack with load obligations in the same hour to arrive at the least-cost market-clearing price for the hour. Once resources are dispatched and market prices are determined, the Dispatch Model singles out Avista resources and loads and values them against the marketplace.

Q. What experience does the Company have using AURORA$_{XMP}$?

A. The Company purchased a license to use the Dispatch Model in April 2002. AURORA$_{XMP}$ has been used for numerous studies, including all of our integrated resource plans and rate filings after 2001. The tool is also used for various resource evaluations, market forecasting, and requests-for-proposal evaluations.

Q. Who else uses AURORA$_{XMP}$?

A. AURORA$_{XMP}$ is used all across North America and in Europe. In the Northwest specifically, AURORA$_{XMP}$ is used by the Bonneville Power Administration, the Northwest Power and Conservation Council, Puget Sound Energy, Idaho Power, Portland General Electric, Seattle City Light, Grant County PUD, Snohomish County PUD, and Tacoma Power.

Q. What benefits does the Dispatch Model offer for this type of analysis?

A. The Dispatch Model generates hourly electricity prices across the Western Interconnect, accounting for its specific mix of resources and loads. The Dispatch Model reflects the impact of regions outside the Northwest on Northwest market prices, limited by known transfer (transmission) capabilities. Ultimately, the Dispatch Model allows the Company to generate price forecasts in-house instead of relying on exogenous forecasts.

The Company owns a number of resources, including hydroelectric plants and natural gas-fired peaking units, which serve customer loads during more valuable on-peak hours. By optimizing resource operation on an hourly basis, the Dispatch Model is able to appropriately value the capabilities of these assets. For example, actual 2008 and 2009 on-peak prices were 23 percent higher than off-peak prices. 2007 on-peak prices were 25 percent higher. Forward on-peak prices for 2011 were 27 percent higher than off-peak prices at the time this case was prepared. For comparison, Dispatch Model on-peak prices for the pro forma period average 29 percent higher than off-peak prices. In summary, the Dispatch Model appropriately values the energy from Avista's resources during on-peak periods in a manner similar to that recently experienced in the Northwest region.

Q. On a broader scale, what calculations are being performed by the Dispatch Model?

A. The Dispatch Model's goal is to minimize overall system operating costs across the Western Interconnect, including Avista's portfolio of loads and resources. The dispatch model generates a wholesale electric market price forecast by evaluating all Western Interconnect resources simultaneously in a least-cost equation to meet regional loads. As the Dispatch Model progresses from hour to hour, it "operates" those least-cost resources necessary to meet load. With respect to the Company's portfolio, the Dispatch Model tracks the hourly output and fuel costs associated with portfolio generation. It also calculates hourly energy quantities and values for the Company's contractual rights and obligations. In every hour the Company's loads and obligations are compared to available resources to determine a net position. This position is balanced using the simulated wholesale electricity market. The cost of energy purchased from or sold into the market is determined based on the electric market-clearing price for the specified hour and the amount of energy necessary to balance loads and resources.

Q. How does the Dispatch Model determine electric market prices?

A. The Dispatch Model calculates electricity prices for the entire Western Interconnect, separated into various geographical areas such as the Northwest and Northern and Southern California. The load in each area is compared to available resources, including resources available from other areas that are linked by transmission corridors, to determine the electricity price in each hour. Ultimately, the market price for an hour is set based on the last resource in the stack to be dispatched. This resource is referred to as the "marginal resource." Given the prominence of natural gas-fired resources on the margin, this fuel is a key variable in the determination of wholesale electricity prices.

Q. How does the Dispatch Model operate regional hydroelectric projects?

A. The model begins by "peak shaving" loads using system hydro resources. When peak shaving, the Dispatch Model determines which hours contain the highest loads and allocates to them as much hydroelectric energy as possible. Remaining loads are then met with other available resources.

Q. Has the Company made any modifications to the database for this case?

A. Yes. Avista's portfolio of resources is modified to reflect actual operating characteristics, natural gas prices are modified to match projected forward prices over the pro-forma period, regional resources are modified where better information is known, and Northwest hydro data is replaced with Northwest Power Pool data.

III. HYDRO MODELING ASSUMPTIONS

Q. How has the Company modeled hydroelectric generation for this case?

A. As in the past, Avista uses historical stream flow data from the Northwest Power Pool (NWPP) to determine hydroelectric generation for its Clark Fork and Spokane River systems. Certain adjustments to the NWPP data are necessary to yield a proper estimate of generation from the model. These adjustments include changes to address the NWPP's tendency to overstate generation in high-flow periods, to account for recent upgrades at our hydroelectric projects, to maintain year-to-year consistency in project operations, to account for encroachment on our Mid-Columbia project shares, and to allow for 2000 irrigation depletion levels.

Q. Why does the NWPP overstate generation on the Company's hydroelectric facilities?

A. The NWPP's regional hydroelectric model is in many ways simplified and therefore does not account for various project operating characteristics. The NWPP model is not granular enough to account for intra-month flow changes. This impact is most significant during the spring months. For example, the Noxon Rapids project has a maximum turbine flow capability of approximately 50,000 cubic feet per second (cfs). The NWPP model will use all water up to 50,000 cfs in a given month to generate power. However, a 50,000 cfs month is not comprised of 28, 29, 30 or 31 days of 50,000-cfs flows. Instead it is made up of flows that range below and above 50,000 cfs. For example, where flows are 20,000 cfs for the first half of the month and 80,000 cfs the second half, the average flow for the period is 50,000 cfs. The NWPP would assume all of this water went through the generation turbines and made power. In fact, the project would in the first half of the month generate with 20,000 cfs and in the second half of the month it would generate with 50,000 cfs. The additional 30,000 cfs in the second half of the month (80,000 - 50,000 = 30,000), or nearly 30 percent of the monthly total, would be spilled in the actual operation of the project.

Q. Does Noxon Rapids have storage capability to account for such variations in flows?

A. Noxon does have some storage, but not near enough to convert all of the intra-month variability of flows into electric energy. A study completed by BorisMetrics explained that on average our hydroelectric dams on the Spokane and Clark Fork Rivers generate 3.7 aMW less than the NWPP estimates. This study was reviewed and accepted in previous cases before this Commission.

Q. Is the Company now experiencing an even greater difference between actual hydroelectric generation and generation from the NWPP model, than that quantified by BorisMetrics?

A. Yes. Relative to the NWPP data used in previous cases, hydro generation on the Clark Fork projects has been overstated by a significant amount on average. Over the past 20 years actual hydroelectric generation has been 319.72 aMW, 3.2 percent (10 aMW) below the NWPP model results for the 50-year period used in rate modeling. Over the past 10 years generation has been 299.08 aMW, or 10.3 percent (31 aMW) below the NWPP modeled results. Lower results in the past 10 years have been driven primarily by lower-than-average stream flows; however, not all of the reduction is driven by lower stream flows. A portion of the overstatement is caused by the design limitations of the model itself.

Q. Please provide additional detail as to why the 10- and 20-year averages were below the 50-year NWPP study period average?

A. There are a number of reasons. Flows in the 1990s were high relative to history, whereas flows in the most recent 10 years have been low relative to average. Also, half of the 20-year average is affected by the use of operating assumptions from our old Clark Fork operating license. New licensing requirements implemented in 2001 have negatively affected power production on the Clark Fork projects. Poor hydroelectric conditions also have played a role in a number of recent years. Additionally, the Company continues to shift reserve obligations to the Clark Fork as we lose Mid-Columbia generation capacity, and as we respond to a marketplace greatly affected by new variable generation resources (i.e., wind). Upgrades at Cabinet Gorge and Noxon Rapids have helped to offset these losses, but the statistics explain that generation levels continue to fall over time.

Q. How is hydro generation calculated in this proceeding?

A. For our Mid-Columbia shares, and for the Spokane River, there is no change from previous filings. Generation data are taken from the NWPP Headwater Benefits Study, adjusted downward by the results of the BorisMetrics study for the Spokane River and Encroachment for the Mid-Columbia projects. For the Clark Fork River projects we continue to use NWPP data for the historical record (1929-1978). However, instead of using energy levels calculated by their model, and adjusted by the BorisMetrics study for overstated generation, the NWPP flow data is used as an input in a new model: the Clark Fork Optimization Package.

Q. Please describe the Clark Fork Optimization Package.

A. The Clark Fork Optimization Package is a mixed-integer linear programming-based system emulating the operation of the Company's Clark Fork projects. It was developed in support of the Company's system operations, financial forecasting, and hydro upgrade efforts. Operating on an hourly time-step, it accurately represents individual turbine and reservoir operations. License constraints (e.g., minimum flows, elevation limits) are honored in all periods. The Clark Fork Optimization Package is comprised of four components which are described below.

Q. In what programming language was the model developed?

A. The Clark Fork Optimization Package is a suite of database (Microsoft Access) and spreadsheet (Microsoft Excel) programs. The Excel programs benefit from WhatsBEST!, an Excel Add-In for Linear, Nonlinear, and Integer Modeling and Optimization. WhatsBEST! was developed by Lindo Systems of Chicago, Illinois in 1979.

Q. What is the first component of the Clark Fork Optimization Package?

A. The first component is the Clark Fork Water Budget Model. It looks over the long-term record and optimizes water flow through the projects to maximize generation values. This step is necessary to recognize the storage capabilities inherent in a hydro project. The long-term optimization is simplified to provide present-day computers with the ability to efficiently solve the equations. Each project is represented by one power curve instead of multiple curves representing individual turbines. Model granularity is daily instead of hourly. Project elevation and flow constraints are retained.

Outputs of the Clark Fork Water Budget Model are weekly beginning and ending project elevations for the Noxon Rapids and Cabinet Gorge projects. These elevations are exported to the second module of the Clark Fork Optimization Package—the Clark Fork Optimization Model Input Database. It is discussed below.

Q. What is the source for hydroelectric flows in the Clark Fork Water Budget Model?

A. The source is the 2007-08 NWPP Headwater Benefits Study. To shape the monthly NWPP data Avista used a daily study obtained from the Bonneville Power Administration (BPA). The BPA data were from the U.S. Army Corp of Engineers study re-creating daily historical flows on the Clark Fork River back to 1929 based on today's river system.

Because of the need for daily inflow values that the NWPP does not provide, and the fact that the BPA data is daily, Avista elected to shape the NWPP monthly data using the daily shapes of the BPA study in each month.

Q. What data does the Clark Fork Optimization Model Input Database contain?

A. The Clark Fork Optimization Model Input Database contains the daily inflows and side flows into the

Company's Clark Fork River projects described above. It also contains representative hourly market prices enabling the model to maximize generation levels in the higher-valued on-peak periods.

Q. What is the third element of the Clark Fork Optimization Package?

A. The third element is the Clark Fork Optimization Model itself. This hourly model uses a mixed-integer optimization routine to maximize the value of the Clark Fork projects over time. Each project is represented in detail, including individual turbine efficiency curves, physical and license-constrained reservoir elevations, tailrace elevations, and minimum and maximum flow constraints.

The Clark Fork Optimization Model shapes generation into the most economically beneficial time periods using the projects' storage reservoirs. It also maximizes the value of generation by flowing water through the turbines at their most economically efficient points on the power curves.

Q. What is the fourth element of the Clark Fork Optimization Package?

A. The fourth element is the Clark Fork Optimization Model Output Database. This database contains results from the Clark Fork Optimization Model, including hourly turbine discharge and spill flows, hourly generation levels, hourly generation values, and hourly reservoir elevations.

Q. How did the Company ensure the Clark Fork Optimization Package accurately reflects the operations and value of the Clark Fork projects?

A. Once the Clark Fork Optimization Package models were completed, it was benchmarked against the Company's 2000-2009 actual results at the Clark Fork projects to ensure its accuracy.

Q. How did the results compare?

A. The Clark Fork Optimization Package initially over-estimated generation relative to the 2000-2009 periods by approximately 6 percent. This result was expected, as Avista does not operate its projects in isolation. Instead the Company uses the Clark Fork projects to meet its load and reserve needs. There are also times where units are down for maintenance or forced outage. To reconcile the Clark Fork Optimization Package with actual operating history, the power curves for each project were therefore reduced by the 6 percent difference. After the benchmarking process, the model generated just over 100 percent of actual generation levels during the 2000-2009 period.

Q. How is the generation then used for ratemaking purposes?

A. The generation levels for each project (Mid-Columbia, Spokane River, and Clark Fork) are input into the dispatch model (AURORAxmp) where Avista's portfolio value is quantified for ratemaking purposes.

Q. Are the models included in the Company's filing?

A. Yes. All four components of the Clark Fork Optimization Package are included in my workpapers, including all input and output data.

Q. Does the Clark Fork Optimization Package account for recent upgrades at the Noxon Rapids project?

A. Yes. Once the original model was benchmarked against recent generation years that did not benefit from upgrades at Noxon, the three newly upgraded units (1, 2, and 3) were input into the model to reflect the higher anticipated generation levels. As Unit 2 will not enter service until April 1, 2011, all proforma periods prior to April 2011 include upgrades only to Units 1 and 3.

Q. How much additional generation did the new units provide based on your modeling?

A. The Company evaluated generation levels with the old Noxon units 1 through 3, and the newly upgraded units over the 50-year period for this case. Generation levels from the upgrades increased by a total of 35,778 MWh (4.08 aMW) a year, or 1.3 percent.

Q. How much additional generation does the new Unit 2 provide?

A. On an annual basis the new Unit 2 included in this case generates 10,326 MWh per year on average over the 50-year period, or 1.18 aMW.

Q. Why did the Company not use similar models in this case for the Spokane River and Mid-Columbia projects?

A. The Clark Fork Optimization Package is the product of several years of work by Avista. The Company has not yet attempted to build a model for the Mid-Columbia due to those projects' significant reliance on upstream (e.g., Grand Coulee Dam) projects that greatly affect their output. A model for the Spokane River projects is under development but is not yet ready for use. The Company hopes to have a working version for the Spokane River system prior to its next rate proceeding. We will subsequently examine a model for the Mid-Columbia projects.

Q. Please explain why the Company developed the Clark Fork Optimization Package.

A. The Clark Fork Optimization Package is the culmination of nearly ten years of work by the Company to bring in-house a tool to enable true optimization of our hydro facilities. In 2002 the Company acquired the Vista suite from Synexus Global. This tool was used to evaluate system operations and support upgrades at our Noxon Rapids and Cabinet Gorge projects. It also was used to evaluate various Spokane River project upgrades. Because of some problems inherent to the Vista model, and very slow solution times, it was retired in the middle of the last decade. We then evaluated other options in the marketplace, and the Company acquired Riverware from the University of Colorado at Boulder. After working with this tool over a number of years it became apparent that it cannot meet our need for efficient unit-level dispatch modeling.

Due to the apparent lack of a strong package for hydro modeling in the marketplace, the Company began developing the Clark Fork Optimization Package in the middle of 2009.

Q. How is the Company using the new Clark Fork Optimization Package in its business operations, and how does it intend to use the tool into the future?

A. The Clark Fork Optimization Package is an essential tool to assist the Company with optimizing hydro system operations, both in short- and long-term planning. Its results are also used for Company budgets, hydro project market valuation studies, and upgrade studies. Given its solution efficiency, it is possible to run large hydro-flow records through it, as is necessary for rate filings such this.

The Company anticipates using its new model to analyze opportunities to increase the value of the Clark Fork projects and lower overall system costs to customers. With this model there is now a potential to analyze a coordination agreement between Clark Fork River project operators that would be similar to the Pacific Northwest Coordination Agreement. Initiation of discussions on this a potential agreement between the various parties with projects on the river has been hampered to a large extent by the lack of a good means to model the values of coordination.

Q. How does the AURORAxmp Dispatch Model operate Company-controlled hydroelectric generation resources?

A. The Dispatch Model treats all hydroelectric generation plants within a load area as a single large plant. The Company's hydroelectric plants are on average, however, more flexible than the average plant used in each load area. To account for this additional flexibility, the Company algebraically extracts its plants from the region and develops individual hydro operations logic for them. Company-controlled hydroelectric resources are separated into three river systems: the Spokane River, the Clark Fork River, and individually separate the Mid-Columbia projects. This separation ensures that the flexibility inherent in these resources is credited to customers in the pro forma exercise.

Q. Please compare the operating statistics from the Dispatch Model to recent historical hydroelectric plant operations.

A. Over the pro forma period the Dispatch Model generates 69 percent of Clark Fork hydro generation during on-peak hours (based on the average of the 50 year hydro record). Since on-peak hours represent only 57 percent of the year, this demonstrates a substantial shift of hydro resources to the more valuable on-peak hours. This is identical to the 5-year average of on-peak hydroelectric generation at the Clark Fork through 2009. Similar performance is achieved for the Spokane and Mid-Columbia projects.

IV. OTHER KEY MODELING ASSUMPTIONS

Q. Please describe your update to pro forma period natural gas prices.

A. Natural gas prices for this filing are based on a 3-month average from October 1, 2009 to December 31, 2009 of the rate period forward prices. Natural gas prices used in the Dispatch Model are presented below in Table No 1.

Table No. 1 - Pro Forma Natural Gas Prices

Basin	$/dth	Basin	$/dth
AECO	5.957	PG&E CITY	6.709
CHICAGO	6.504	RATHDRUM	6.265
CIG	5.882	SJUAN BASIN	5.975
EL PASO	6.056	SOCAL	6.277
MALIN	6.345	STANFIELD	6.265
NECT	6.566	SUMAS	6.372
NWPC RM	5.904	Henry Hub	6.424

Q. What is the Company's assumption for rate period loads?

A. Rate period loads (October 2010 through September 2011) used in this case are taken from the Company's load forecast completed in July 2009. As this load is generated using "normal weather," it eliminates the need for a weather-normalization adjustment. Removing the 2009 actual (test year) generation from the Clearwater (previously known as Potlatch) cogeneration facility, from the October 2010 to September 2011 proforma period loads, results in system loads of 1,070.4 aMW as filed in this proceeding.

The Company's latest energy loads and resources tabulation (L&R) is attached in Exhibit No.5, Schedule 1.

Q. Please discuss the availability assumptions for your thermal and gas generating facilities.

A. For baseload generating facilities such as Coyote Springs 2, Kettle Falls Generating Station, and Colstrip, we use a 5-year average through 2009 to estimate long-run operating performance. The following table summarizes the average forced outage rates for each of the Company's thermal and gas generation facilities.

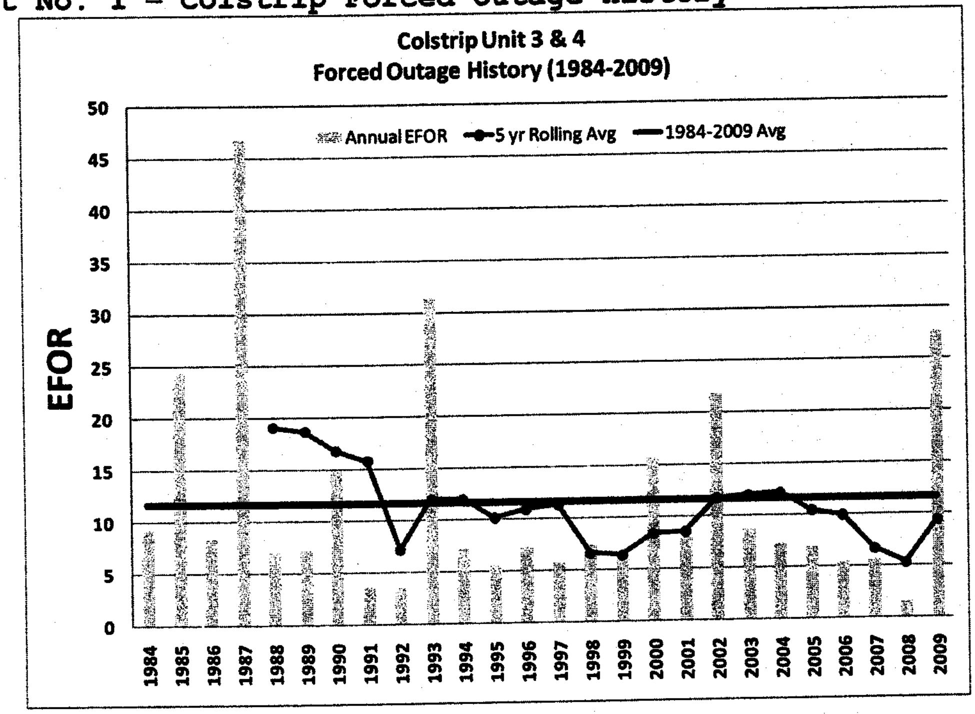
Table No. 2 – Equivalent Forced Outage Rates (EFOR) Of Avista Thermal and Gas Plants

Plant	EFOR	Plant	EFOR
Colstrip	9.36%	Rathdrum	5.00%
Coyote Springs	5.07%	Northeast	5.00%
Lancaster	3.00%	Kettle Falls	1.58%
Boulder Park	15.00%	Kettle Falls CT	5.00%

Q. Colstrip had an extended outage in 2009. Would it be reasonable to exclude this single year from the average?

A. No. In the past, various parties have advocated elimination of years where the Colstrip plant had a high forced outage rate, assuming that such years were abnormal and should not be expected to re-occur. This is in fact not the case. The 5-year average of 9.36 percent falls well below the 11.6 percent lifetime plant average. In the 25-year history of Colstrip operations there have been seven years (one event every 3.7 years) where forced outage rates exceed 10 percent. It is therefore not uncommon for some years to have outages like the one experienced in 2009. See Chart No. 1 for a history of forced outages at Colstrip.

Chart No. 1 – Colstrip Forced Outage History



Q. Please provide a summary of the monthly and average Northwest forward natural gas and electricity prices that directly affect proforma costs.

A. Table No. 3 presents monthly modeled natural gas and electricity prices for this case.

Table No. 3 – Dispatch Model Prices Summary

Month	CS2 and Rathdrum Gas ($/dth)	NE/BP/KF GT Gas ($/dth)	Flat 7x24 Mid-C ($/MWh)	Month	CS2 and Rathdrum Gas ($/dth)	NE/BP/KF GT Gas ($/dth)	Flat 7x24 Mid-C ($/MWh)
Oct-10	5.779	6.060	48.90	Apr-11	6.047	6.339	41.15
Nov-10	6.180	6.477	53.11	May-11	6.012	6.302	33.30
Dec-10	6.585	6.898	58.13	Jun-11	6.069	6.361	31.31
Jan-11	6.703	7.021	57.02	Jul-11	6.141	6.437	48.91
Feb-11	6.699	7.017	54.80	Aug-11	6.205	6.503	57.38
Mar-11	6.526	6.837	50.49	Sep-11	6.237	6.536	55.77
				Average	6.265	6.566	49.19

Q. Are Mid-Columbia electric prices from the Dispatch Model the same as the Forward Market?

A. No, Mid-Columbia electric prices from the Dispatch Model differ from the forward market for a variety of reasons. This being said, they generally are very close as in this filing. Forward market prices are not only an expectation of future prices, but they contain an adjustment for risk or unknown future conditions, based on the premise you can "lock in" prices. The Dispatch Model is a spot market model that forecasts prices for a specific time in the future given load, hydro, and fuel price conditions. Average annual Mid-Columbia prices in the forward market are \$54.19/MWh on-peak and \$42.56/MWh off-peak (based on average forwards between 10/1/2009 and 12/31/2009). The average Mid-Columbia price from the Dispatch Model is \$53.66/MWh on-peak and \$41.65/MWh off-peak.

V. DEMAND CLASSIFICATION

Q. Witness Knox explains that the Company is changing its methodology for allocating production costs between capacity and energy based on your work. Please explain your concerns with the present methodology and what you propose as a better way to allocate production costs.

A. The historical method to allocate production costs goes through the various FERC accounts and attempts to determine which costs are for demand and which are for energy. As an example, all thermal fuel in FERC account 501 is allocated to energy production, and all "Other" production costs are allocated to demand. Unfortunately, the problem is not this simple. Some of the "Other" costs are almost certainly related to the production of energy and, possibly more surprising to some, various fuel costs can be related to providing capacity (demand).

Q. How can some of the costs in your example be considered energy?

A. To produce energy it is necessary to maintain a generation plant in a ready state to do so. The "Other" category is an excellent example of a somewhat arbitrary allocation to demand that is done for lack of any better approach. The "Other" category for both production plant (300 series) and O&M (500 series) includes our gas-fired plants and the Lancaster agreement. The "Other" category is allocated 100 percent demand. Because of this the Company has historically removed our Coyote Springs 2 gas-fired CCCT plant from the "Other" category and instead allocated its costs based on the overall Thermal Peak Credit figure. But other plants are not broken out this way. Boulder Park, Rathdrum and Northeast are all allocated 100 percent to demand by being in the "Other" category, yet clearly a portion of their plant and O&M costs are attributable to energy production. It is likely that a portion of "Other" expenses are indeed to the benefit of energy production, yet the old allocation method assumed all such costs are attributable to demand.

Q. How can a fuel cost be classified as demand?

A. Demand, or capacity, is really the production of energy at the time of system peak. Fuel is consumed during periods of peak operation. It would be unreasonable to not consider this fact. And simply because the majority of a fuel expense is incurred outside of peak operating periods does not mean that no fuel should be allocated to demand.

Q. Do you have any other concerns about the present demand allocation methodology?

A. Yes. Presently all of our generation assets are melded together to create an allocation. Further, a simple accounting methodology is employed to estimate what it might cost to construct our older facilities today. But it is not realistic to assume that historical investments represent our present costs of capacity (demand). Such allocations should be based on the decisions we are making today, and on the costs we incur today when customers consume electrical energy during times of system peak.

Instead of trying to create an incremental demand cost through a complicated and potentially inaccurate escalation of historical expenses, we should instead use present information for plants we are building to meet new customer demands.

Q. Please explain the Company's recommended method for classifying electricity production costs between energy and demand.

A. The Company believes we should link the classification methodology to the Integrated Resource Plan (IRP). The IRP process is an exercise to meet customer load growth in a least-cost fashion. Central to the equation is the level of our customers' coincident peak demand. We construct a least-cost mix of resources providing both the energy and capacity.

Q. What resource does the Company propose be used for splitting demand and energy costs from overall production expenses?

A. We believe that we should use the incremental capacity resource from our latest IRP—a gas-fired CCCT. The Company, using its IRP models, calculated the costs of capacity and energy from this resource, and used that figure to allocate overall production costs.

Q. How did the Company determine a split between energy and capacity for the incremental resource?

A. For the IRP the Company models the Western Interconnect wholesale power marketplace using AURORAxmp. AURORAxmp dispatches available resources against electricity loads on an hourly basis. The IRP uses AURORAxmp to look at costs out 20 years and "mark-to-market" (MTM) each potential resource option reasonably available to the Company in the future. The dispatched value of the CCCT (i.e., market sales price less fuel and variable maintenance and operation costs) is tracked hourly over the 20-year IRP timeframe. Additionally, for the IRP the Company models the 20-year future over 250 Monte Carlo iterations to reflect volatility created by various factors including natural gas prices, load variability and forced outage rates. In other words, for each of the 20 years evaluated for the IRP there are 250 MTM values for the CCCT. The annual average MTM figures represent the energy value generated by the plant. Remaining costs not recovered in the wholesale marketplace are defined as capacity. The ratio of those costs remaining after dispatch into the wholesale marketplace (MTM values) relative to the entire cost of the CCCT plant equals the share of production costs then attributed to demand in the cost of service models.

Q. What were the results of your analysis?

A. The analysis allocates 38.1 percent of production costs to demand. Company witness Knox discusses how this demand allocator compares with that derived from the prior peak-credit methodology.

Q. Where are the calculations referenced above contained?

A. The calculations are contained in my work papers in an Excel file called "Demand_Classification_Final." A summary of the results is presented in Exhibit No.5, Schedule 2.

Q. How should the demand allocation be applied to production costs?

A. Because the analysis does not differentiate between fixed and variable costs, but instead evaluates all such costs, it should be applied across the board to all production costs.

VI. RESULTS

Q. Please summarize the results from the Dispatch Model that are used for ratemaking.

A. The Dispatch Model tracks the Company's portfolio during each hour of the pro forma study. Fuel costs and generation for each resource are summarized by month. Total market sales and purchases, and their revenues and costs, are also determined and summarized by month. These values are contained in Exhibit No.5, Confidential Schedule 3 and were provided to Mr. Johnson for use in his calculations. Mr. Johnson adds resource and contract revenues and expenses not accounted for in the Dispatch Model (e.g., fixed costs) to determine net power supply expense.

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

A. Yes, it does.

DAVID J. MEYER
VICE PRESIDENT AND CHIEF COUNSEL OF
REGULATORY & GOVERNMENTAL AFFAIRS
AVISTA CORPORATION
P.O. BOX 3727
1411 EAST MISSION AVENUE
SPOKANE, WASHINGTON 99220-3727
TELEPHONE: (509) 495-4316
FACSIMILE: (509) 495-8851
DAVID.MEYER@AVISTACORP.COM

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION FOR THE AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE TO ELECTRIC AND NATURAL GAS CUSTOMERS IN THE STATE OF IDAHO	CASE NO. AVU-E-10-01 EXHIBIT NO. 5 CLINT G. KALICH

FOR AVISTA CORPORATION

(ELECTRIC ONLY)

Load and Resource Balance (aMW)

		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Energy Position											
	REQUIREMENTS	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1	Native Load	-1,130	-1,152	-1,174	-1,197	-1,216	-1,236	-1,260	-1,278	-1,296	-1,315
2	Contract Obligations	-139	-139	-139	-139	-64	-64	-12	-11	-11	-11
3	Total Requirements	-1,269	-1,291	-1,313	-1,336	-1,280	-1,299	-1,272	-1,290	-1,307	-1,326
	RESOURCES										
4	Contract Rights	482	468	466	466	391	381	338	338	317	292
5	Hydro	505	493	495	495	495	495	495	491	481	481
6	Thermal Resources	533	520	522	532	543	529	533	546	531	532
7	Total Resources	1,520	1,481	1,483	1,493	1,429	1,406	1,366	1,375	1,330	1,305
8	**POSITION**	251	190	170	157	148	106	95	86	23	21
	CONTINGENCY PLANNING										
9	Contingency Total	-221	-218	-219	-220	-221	-221	-222	-223	-206	-189
10	Peaking Resources	130	131	129	140	140	140	140	140	140	140
11	**CONTINGENCY NET POSITION**	**160**	**104**	**80**	**77**	**68**	**24**	**13**	**3**	**-43**	**-70**
12	**POSITION EXCLUDING MAINT.**	201	157	134	109	88	59	44	19	-11	-39

Combined-Cycle Combustion Turbine (from 2009 IRP)

Project Size	250	MW
Capital Cost	1,564	$/kW (2010)
Transmission Cost	54	$/kW (2010)
Total Capital Cost	**1,618**	**$/kW (2010)**
Fixed O&M	11.22	$/kW-yr (2010)
Variable O&M	3.36	$/MWh
Inflation	2.0%	annually

Column No	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Note			from 2009 IRP	from 2009 IRP	Total Capital * Col 4	from 2009 IRP	FO&M * 250 MW	Col 3 * VO&M + Inf.	Cols 5-8	Col 9 / 250 / 1000	Col 12 / 250 / 1000	oper. margin from 2009 IRP, plus Cols 6, 8	Cols 9 + 12	(Col 10 + 11) / 250 / 1000	Cols 5 + 7	Col 13 / Col 15
		Year	Annual Generation (MWh)	Capital Recovery Factor	Capital Recovery ($mil)	Fuel ($mil)	Fixed O&M ($mil)	Variable O&M ($mil)	Total ($mil)	Total ($/kW-yr)	Market Value ($/kW-yr)	Market Value ($mil)	Net Value ($mil)	Net Value ($/kW-yr)	CCCT Fixed Costs ($mil)	Demand Share (%)
Levelized Cost					($54.72)	($21.15)	($3.21)	($6.11)	($85.19)	($340.77)	$252.40	$63.10	($22.09)	($88.37)	(57.93)	[redacted]
	1	2010	1,421,996	15.4%	(62.29)	(15.45)	(2.81)	(4.77)	(85.31)	(341.24)	150.86	37.71	(47.60)	(190.38)		
	2	2011	1,432,163	17.5%	(70.69)	(15.65)	(2.86)	(4.90)	(94.11)	(376.44)	155.26	38.81	(55.30)	(221.18)		
	3	2012	1,564,110	16.8%	(67.76)	(15.85)	(2.92)	(5.47)	(91.99)	(367.97)	175.87	43.97	(48.02)	(192.10)		
	4	2013	1,624,399	16.0%	(64.91)	(16.24)	(2.98)	(5.80)	(89.92)	(359.67)	198.03	49.51	(40.41)	(161.64)		
	5	2014	1,658,096	15.4%	(62.14)	(17.30)	(3.04)	(6.03)	(88.50)	(354.01)	223.03	55.76	(32.75)	(130.98)		
	6	2015	1,665,372	14.7%	(59.44)	(19.36)	(3.10)	(6.18)	(88.07)	(352.28)	242.77	60.69	(27.38)	(109.51)		
	7	2016	1,664,088	14.0%	(56.80)	(21.09)	(3.16)	(6.29)	(87.34)	(349.36)	259.11	64.78	(22.56)	(90.25)		
	8	2017	1,646,626	13.4%	(54.23)	(22.69)	(3.22)	(6.33)	(86.47)	(345.89)	271.81	67.95	(18.52)	(74.08)		
	9	2018	1,641,165	12.8%	(51.69)	(24.83)	(3.29)	(6.43)	(86.24)	(344.94)	301.00	75.25	(10.99)	(43.94)		
	10	2019	1,596,935	12.2%	(49.16)	(26.87)	(3.35)	(6.37)	(85.75)	(343.00)	303.29	75.82	(9.93)	(39.71)		
	11	2020	1,619,380	11.5%	(46.63)	(26.79)	(3.42)	(6.58)	(83.41)	(333.65)	312.50	78.13	(5.29)	(21.14)		
	12	2021	1,642,987	10.9%	(44.09)	(25.83)	(3.49)	(6.80)	(80.21)	(320.82)	321.74	80.44	0.23	0.92		
	13	2022	1,633,936	10.3%	(41.56)	(25.95)	(3.56)	(6.88)	(77.95)	(311.80)	319.49	79.87	1.92	7.68		
	14	2023	1,645,964	9.6%	(39.03)	(27.09)	(3.63)	(7.06)	(76.80)	(307.21)	339.40	84.85	8.05	32.19		
	15	2024	1,675,118	9.0%	(36.50)	(27.19)	(3.70)	(7.32)	(74.70)	(298.81)	359.46	89.86	15.16	60.65		
	16	2025	1,660,949	8.4%	(33.96)	(29.15)	(3.78)	(7.39)	(74.28)	(297.12)	373.65	93.41	19.13	76.53		
	17	2026	1,650,350	7.8%	(31.43)	(30.18)	(3.85)	(7.48)	(72.94)	(291.75)	385.98	96.50	23.56	94.23		
	18	2027	1,656,390	7.1%	(28.90)	(29.99)	(3.93)	(7.65)	(70.47)	(281.87)	392.34	98.08	27.62	110.47		
	19	2028	1,675,123	6.5%	(26.36)	(29.86)	(4.01)	(7.88)	(68.11)	(272.45)	407.22	101.80	33.69	134.77		
	20	2029	1,629,371	5.9%	(23.83)	(32.12)	(4.09)	(7.84)	(67.88)	(271.52)	412.20	103.05	35.17	140.68		

CONFIDENTIAL

Dispatch Model Summary Output

Pages 1 through 3

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