Exhibit No. ___(CGK-1T)

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-08______

DIRECT TESTIMONY OF

CLINT G. KALICH

REPRESENTING AVISTA CORPORATION

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 Avista Utilities as a Senior Power Resource Analyst.

In 2001, I accepted my current position, assisting the Company 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, hereinafter referred to as the "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. Finally, I will present the modeling results provided to Company Witness Mr. Johnson for his power supply pro forma adjustment calculations.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring two exhibits marked Exhibit No. ___(CGK-2) and Exhibit No. ___(CGK-3). Exhibit No. ___(CGK-2) provides a forecast of Company load and resource positions from 2009 through 2018. Exhibit No. ___(CGK-3) provides summary output from the AURORA$_{XMP}$ dispatch model. All information contained in the exhibits was 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 AURORA$_{XMP}$ system dispatch model ("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 January 1, 2009 through December 31, 2009. 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 9.0., released in November 2007, and the latest available database for it (North_American_DB_2007-02).

Q. Please briefly describe the Dispatch Model.

A. The AURORA$_{XMP}$ electric market model was developed by EPIS, Inc. of Sandpoint, Idaho. AURORA$_{XMP}$ 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 AURORA$_{XMP}$ in April 2002. AURORA$_{XMP}$ has been used for numerous studies, including the Company's 2003, 2005, and 2007 Integrated Resource Plans ("IRPs"), our 2004 general rate case filing in the State of Idaho, and our 2005 and 2007 general rate case filings before this Commission. The tool is also used for various resource evaluations, including requests for proposals.

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

A. AURORA$_{XMP}$ is used all across North America. 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, and Tacoma Power, among others.

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 2006 on-peak prices were 31.9% higher than off-peak prices. In 2007 the difference was 29.9%. For comparison, Dispatch Model on-peak prices for the pro forma period average 30% 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 determine a net position. This net 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, and how are prices used to calculate market purchases and sales?

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?

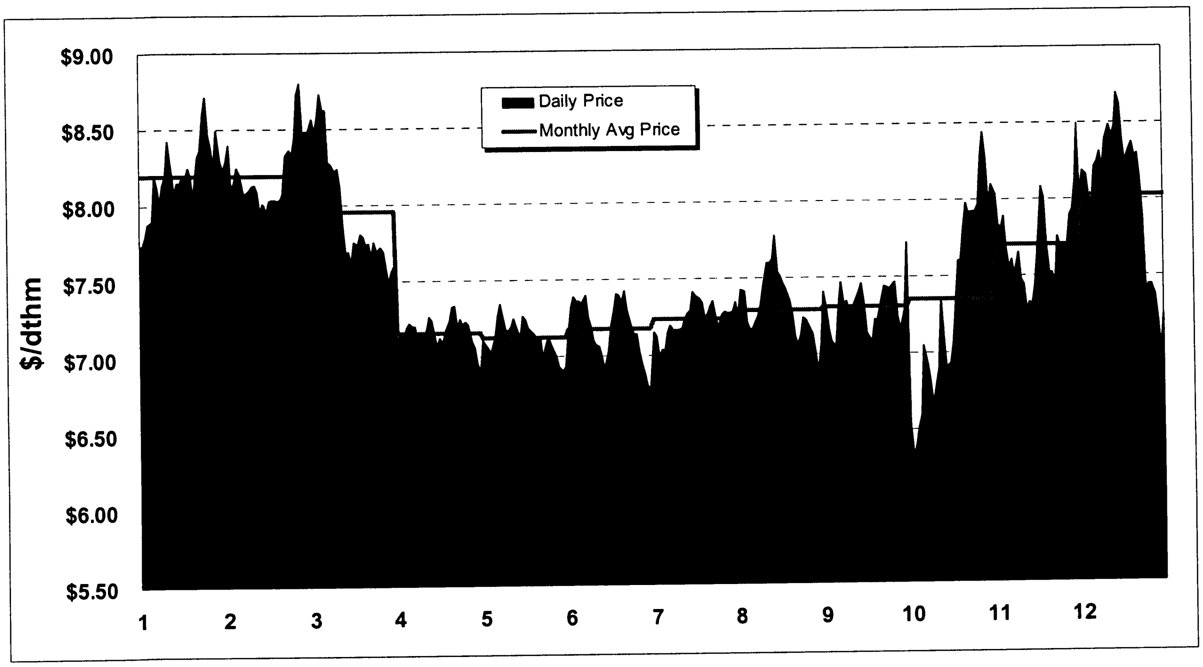
A. Yes. Avista's portfolio of resources is modified to reflect actual operating characteristics, natural gas prices are modified to match projected forward prices over the pro-forma period, regional resources are modified where better information is known, and northwest hydro data is replaced with Northwest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

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 of 2009 monthly forwards from October 1, 2007 to December 31, 2007. This method is consistent with the 2007 rate settlement in Commission Order No. 05 in Docket No. UE-070804 and the

2005 Commission Order No. 05 in Docket No. UE-050482, and in the 2005 Puget Sound Energy Order No. 05 in Docket No. UE-040641. Prices are fitted to a daily shape based on daily spot market prices at AECO between January 2003 and December 2007. Daily and monthly gas price shapes at AECO are shown in Chart No. 1. Other basins retain the same daily shape.

Chart No. 1 – Daily Natural Gas Price Shape at AECO



Natural gas prices are modified to ensure prices across the Western Interconnect are consistent with changes made to the Northwest. Annual average natural gas prices at the various trading hubs are presented below in Table No 1.

Table No. 1 – Pro Forma Natural Gas Prices

Basin	Price ($/dth)	Basin	Price ($/dth)
AECO	7.55	Stanfield	7.92
Malin	7.99	Sumas	8.15
Spokane	8.28	Henry Hub	8.36
Rockies	7.02	Topock	7.97

Q. What hydro record is the Company using in this filing?

A. The Company bases this case on the 50-year hydrological record beginning in 1929. This period is the same as adopted in the Company's 2005 general rate case and memorialized in Commission Order No. 05 in Docket No. UE-050482. It is also the same as the period adopted in our 2007 Settlement (Commission Order No. 05 in Docket No. UE-070804). Data is sourced from the Northwest Power Pool's (NWPP) 2006-07 Headwater Benefits Study. This study is the latest available.

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

A. Rate period loads used in this case are taken from the Company's 2008 load forecast completed in July 2007. As this load is generated using "normal weather," it eliminates the need for a weather-normalization adjustment. The Company's latest energy and capacity loads and resources tabulations (L&Rs) are attached in Exhibit No.___(CGK-2). As the L&Rs show, 2009 system loads are expected to equal 1,118 aMW including a large co-generator's entire load. For this filing system loads are reduced by 57.3 aMW of co-generation by the large industrial customer load located in Idaho. This adjustment lowers the rate period loads to 1,061 aMW.

Q. How does Coyote Springs 2 dispatch relate to historical dispatch?

A. Coyote Springs 2 was modified from the default database to more accurately simulate actual plant operations. Chart 2 shows actual Coyote Springs 2 dispatch for calendar year 2007.

Chart No. 2 – CS2 Dispatch (Calendar Year 2007 Actual)

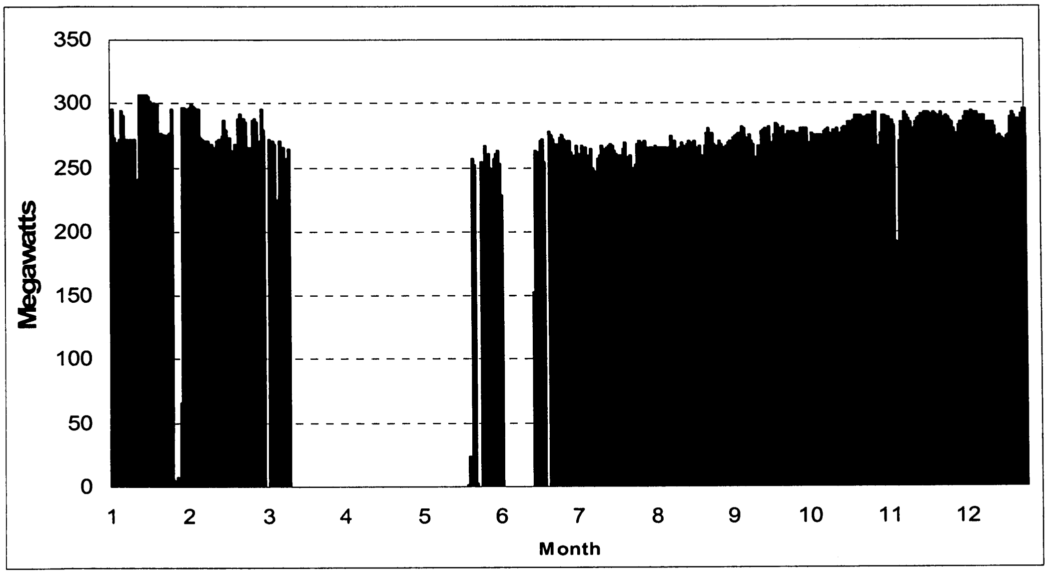
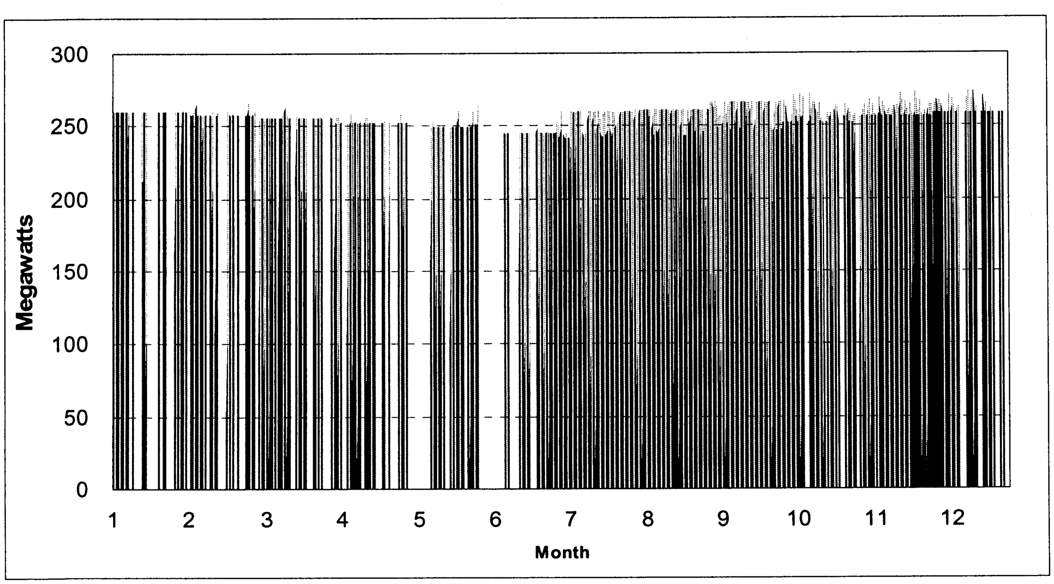


Chart 3 shows Coyote Springs 2 during the 2009 pro forma period prior to modifying database assumptions.

Chart No. 3 – CS2 Dispatch (2009 Pro Forma with AURORA$_{XMP}$ default logic)



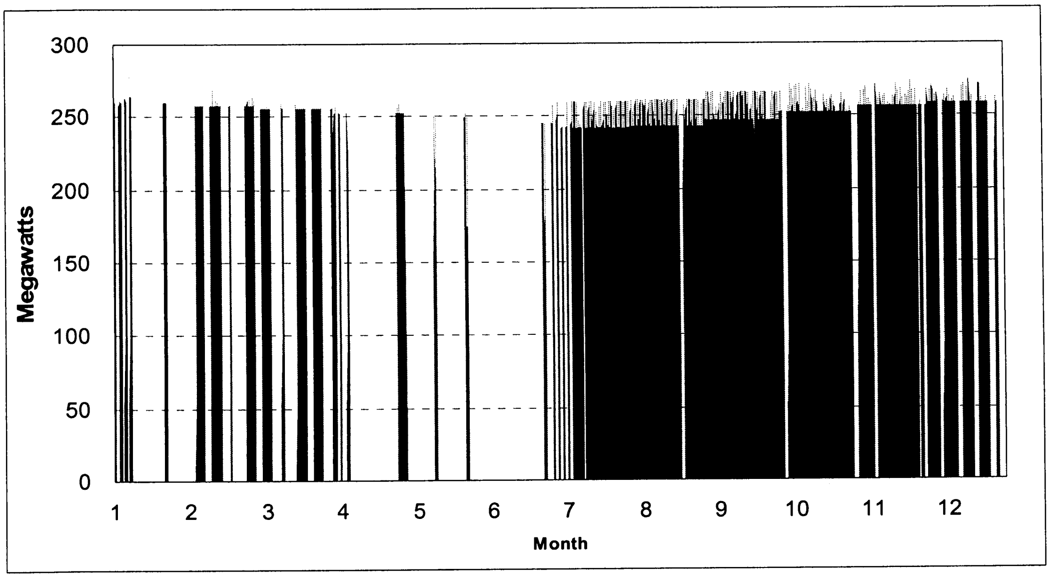
The Dispatch Model using EPIS' default database starts and shuts down Coyote Springs 2 nearly every day (269 starts), and the plant generates 121 aMW. This operational pattern is not realistic and is beyond the operational capability of Coyote Springs 2. To resolve this modeling problem, the Company modified the start-up cost, start-up fuel, minimum up and minimum down times for the plant. This same methodology was tested for all Western Interconnect combined cycle plants, but such modification had an adverse effect on the overall on/off peak price spread, resulting in a much higher differential than witnessed historically or that is present in the forward markets. Avista continues to work with EPIS, the developer of AURORA$_{XMP}$, to address our concerns with overall CCCT plant dispatch across the Western Interconnect.

Start-up costs were identified as a key driver to the incorrect dispatch behavior of Coyote Springs 2. The EPIS default start-up cost for Coyote Springs 2 is $12.61 per MW start-up cost, or $3,429. Based on our experience, this cost is low by orders of magnitude. Based on Company experience each cold start at Coyote Springs 2 includes 1,891 decatherms of fuel and $10,000 of estimated O&M costs. Assuming the average annual Stanfield natural gas price of $7.92 per decatherm, the start up costs is estimated to be $24,977 (1,891 x $7.92 + $10,000).

The second modification made by the Company was to change the minimum up and minimum down times from 16 hours and 8 hours respectively, to 20 hours up an 20 hours down. Minimum up time, not only indicates how long the unit must stay on-line, but also is used to allocate start-up costs for commitment decisions.

These two changes, when taken together, provide for a much more reasonable dispatch of Coyote Springs 2, as shown in Chart No. 4.

Chart No. 4 – CS2 Dispatch (2009 Pro Forma Average Hydro)



Q. How does the 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-Columbian 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 66.9% of the Company's hydro generation during on-peak hours (based on average water). Since on-peak hours represent only 57% of the year, this demonstrates a substantial shift of hydro resources to the more expensive on-peak hours. This is nearly identical to the 5-year average of on-peak hydroelectric generation through 2007: 66.4%.

Q. What is the Company assuming for natural gas prices in the pro forma period for Company-owned gas-fired resources?

A. Natural gas prices are a function of average commodity cost, transportation, and applicable taxes. Consistent with our last general rate case filing, natural gas prices were set using an average of witnessed forward prices, specifically the three-month period ending December 31, 2007. The average price for the pro forma year equals $7.92 per decatherm at Rathdrum and CS2, and $8.28 per decatherm for Northeast, Boulder Park, and the Kettle Falls CT.

Q. Please provide a summary of the monthly and average Northwest Forward natural gas and electricity prices?

A. Table No. 2 presents modeled natural gas and electricity prices.

Table No. 2 – Dispatch Model Prices Comparison

Month	CSII & Rathdrum Gas ($/dth)	NE/BP/ KFCT Gas ($/dth)	Mid-C ($/MWh)	Month	CSII & Rathdrum Gas ($/dth)	NE/BP/ KFCT Gas ($/dth)	Mid-C ($/MWh)
Jan-09	8.594	8.988	57.95	Jul-09	7.574	7.927	57.90
Feb-09	8.599	8.993	62.66	Aug-09	7.626	7.981	65.03
Mar-09	8.357	8.741	58.97	Sep-09	7.643	7.999	61.49
Apr-09	7.497	7.846	52.12	Oct-09	7.688	8.046	59.02

May-09	7.455	7.803	47.25	Nov-09	8.068	8.441	63.09
Jun-09	7.508	7.858	41.33	Dec-09	8.393	8.779	62.04
				Average	**7.92**	**8.28**	**57.39**

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. The 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 $68.38/MWh on-peak and $54.25/MWh off-peak (based on average forwards between 10/1/2007 and 12/31/2007). The average Mid-Columbia price from the Dispatch Model is $63.68/MWh on-peak and $48.99/MWh off-peak.

Q. You stated earlier in your testimony that you are using the NWPP hydro study as the basis for your hydro dataset. Does the NWPP study include the Cabinet Unit 4 or the Noxon Rapids 4 upgrade?

A. No, the NWPP study does not include the Cabinet Unit 4 or Noxon Rapids 4 upgrades. The data will be included in our next data submittal to the NWPP. I expect the upgrade to be reflected in the 2008 NWPP study.

Q. How have you accounted for the Cabinet Unit 4 and Noxon Rapids 4 upgrades in the pro forma?

A. The Cabinet Unit 4 upgrade is expected to generate 1.98 and Noxon Rapids 4 is expected to generate 2.33 average megawatts of additional energy in an average water year. To account for this energy in the pro forma, the unit sizes are increased from 55.2 MW to 59.7 MW and 105 MW to 111.4 MW, respectively. The Dispatch Model then generates at the upgraded energy and capacity levels when the units are dispatched.

IV. 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. ___(CGK-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.