Exhibit No. ___ (CGK-1T)

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-06________

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 ratemaking, 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 dispatch model, hereinafter referred to as the "Dispatch Model" or "AURORA." 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 Electricity Coordination Council ("WECC") 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 present the Company's 2007 pro forma loads being used for this case. Finally, I will present the modeling results provided to Company witness Mr. Johnson for his power supply pro forma adjustment calculations.

Below is a table of contents for my testimony:

Description		Pages
I.	Introduction	1-3
II.	The Dispatch Model	3-10
III.	Load Forecast	11-14
IV.	Results	14-15

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring Exhibit Nos. ___(CGK-2) (Loads and Resources Tabulation) and ___(CGK-3) (AURORA Summary Output). All information contained in the exhibits was prepared either by me or 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 Electric Market Model software package for determining power supply costs. The model optimizes the dispatch of Company-owned resources and contracts in each hour of the pro forma year. The pro forma period is January 1, 2007 through December 31, 2007. It reflects true system operations by evaluating future resource decisions on an hourly basis.

Q. Are the assumptions utilized for the Dispatch Model in this proceeding similar to those used in the 2005 general rate case before the Commission?

A. Yes, they are similar to the assumptions used in both the settlement document and the Commission order, with a few exceptions. Forward market natural gas prices change over time. Natural gas prices have been updated using the approved 2005 general case methodology (i.e. average of three months of forward prices) to reflect more recent forward market prices. Second, Colstrip fuel prices are modified to reflect the latest available cost data from the mine. The Kettle Falls fuel price is also modestly different, reflecting updated calculations based on current contracts with fuel suppliers and existing inventory. Avista loads were updated to reflect 2007 forecast values. Finally, modifications were made to reflect changes in our resource portfolio since the 2005 general rate case. These changes were a 10 MW (1.1 aMW) upgrade of Cabinet Unit 4, a 28 MW (4.2 MW Company share) upgrade at Colstrip Unit 3, and a 28 MW (4.2 MW Company share) upgrade at Colstrip Unit 4.

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 period adopted in the Company's 2005 general rate case. The Northwest Power Pool (NWPP) updates its operating assumptions to reflect modest changes in the system from year to year; this pro forma reflects the latest NWPP study (2006).

Q. Please briefly describe the Dispatch Model.

A. AURORA is a fundamentals-based tool that contains demand and resource data for the entire WECC, and 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, by 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?

A. The Company purchased a license to use AURORA in April 2002. AURORA has been used for numerous studies, including the Company's 2003 and 2005 Integrated Resource Plans (IRPs), our 2004 general rate case filing in the State of Idaho, and our 2005 general rate case filing before this Commission. AURORA also is being used in the Company's 2007 IRP.

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

A. The Dispatch Model generates hourly electricity prices across the WECC, accounting for its specific mix of resources and loads. The Dispatch Model reflects the impact of regions outside of 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, that 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 2005 on-peak prices were 18.3 percent greater than off-peak prices. By comparison, Dispatch Model on-peak prices for the pro forma period averages 19.0 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 WECC, including Avista's portfolio of loads and resources. The Dispatch Model generates a wholesale electric market price forecast by evaluating all WECC 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 the generation portfolio. 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 operate regional hydroelectric projects?

A. The model begins by lowering hourly regional loads by forecasted wind energy and must-run generators. It then "peak shaves" remaining 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.

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 generally more flexible than the average plant used in each load area. For example, Noxon Rapids is able to shift a substantially higher percentage of its electricity generation into higher-value on-peak hours relative to other plants in the region. 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 Mid-Columbia, the Spokane River, and the Clark Fork River 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 hydro plant operations.

A. Over the pro forma period, the Dispatch Model dispatches 68.7 percent of the Company's hydro generation during on-peak hours. 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. The January 2001 through April 2006 average of on-peak hydroelectric generation was 67.8 percent; the average since January 1989, the first year our Company began electronically archiving hourly hydroelectric generation, was 68.0 percent. The Dispatch Model therefore shapes modestly more hydroelectric generation to the on-peak hours than our operating history shows, to the benefit of customers.

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

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 for calendar year 2007 during the three-month period ending May 31, 2006. Separate averages were calculated for each of the Company's natural gas-fired plants, as well as for Henry Hub. Although the Company does not dispatch any of its plants using gas indexed to Henry Hub, AURORA uses Henry Hub as a basis for dispatching other natural gas-fired resources in the WECC. The average gas price for the pro forma year equals $8.676 per decatherm at Rathdrum and CS2, and $9.073 per decatherm for Northeast, Boulder Park, and the Kettle Falls CT. For comparison, the average Henry Hub price for the period is $9.333 per decatherm. See Table 1 on page 9 of my testimony for a listing of monthly natural gas prices for the Company's gas-fired plants.

Q. The Company used bidding factors in its last general rate case filing to align modeling results with then-current forward market conditions. Is the Company using bidding factors in this filing?

A. The Company is not using bidding factors in this case. In the 2005 rate case the Company found in pre-filing runs that AURORA was over-estimating forward electricity prices when compared to then-forward electricity prices. The Company used bidding factors to align the AURORA forecast of Mid-Columbia electricity prices for 2006 with forward market prices for 2006. AURORA's ability to forecast market prices is highly dependent on the underlying database of resources, their assumptions, and forecasted loads. At the time our last general case was prepared, the Company was concerned that the latest database provided by EPIS with the AURORA model contained assumptions that adversely affected its market forecast. Given the limited time available to modify the database, bidding factors were found to provide an efficient means to correct the model's behavior.

There was significant concern over the Company's use of bidding factors in the last case. Therefore, the Company increased its efforts to address problems in the underlying AURORA database before this filing. Our concerns were voiced to the vendor. The latest database does a much better job of forecasting market prices than the version used for the last general rate case. In addition, the Company modified Northwest load, transmission constraints, and hydro shaping abilities to make these characteristics consistent with recent history and to true up model forecasted and forward prices.

Q. How do the results of the model compare to the forward market prices?

A. Table 1 presents modeled natural gas and electricity prices in the Dispatch Model. It also presents forward market prices for electricity as a comparison. As shown, the pro forma electricity price equals $62.89 per MWh versus $62.60 per MWh in the forward market. While there are variances month-to-month, the annual averages of the model results and the foreword market prices are similar, and the overall results are reasonable for ratemaking purposes.

Table 1 – Dispatch Model Prices Comparison

Month	Forward CSII & Rathdrum Gas Prices ($/dth)	Forward NE/BP/ KFCT Gas Prices ($/dth)	Forward Electricity Prices ($/MWh)	Pro forma Electricity Prices ($/MWh)	Difference From Forwards ($/MWh)	Difference From Forwards (%)
Jan-07	9.668	10.105	76.97	73.86	(3.10)	-4%
Feb-07	9.669	10.105	74.51	74.15	(0.35)	0%
Mar-07	9.510	9.941	67.78	66.71	(1.07)	-2%
Apr-07	8.025	8.396	50.72	55.73	5.02	10%
May-07	7.847	8.211	39.46	39.76	0.30	1%
Jun-07	7.925	8.292	35.10	33.83	(1.26)	-4%
Jul-07	8.133	8.509	48.48	46.85	(1.63)	-3%
Aug-07	8.200	8.577	75.40	69.30	(6.10)	-8%
Sep-07	8.261	8.642	75.64	72.88	(2.76)	-4%
Oct-07	8.364	8.748	58.14	67.98	9.83	17%
Nov-07	8.925	9.332	68.90	73.64	4.74	7%
Dec-07	9.587	10.020	80.56	79.55	(1.01)	-1%
Average	**8.676**	**9.073**	**62.60**	**62.89**	**0.30**	**0%**

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

A. No, the NWPP study does not include the Cabinet 4 upgrade. As the Cabinet 4 upgrade is not scheduled to be completed until early 2007, it will not be included in our submittal to the NWPP until the upgrade has been completed. This is standard procedure under the Coordination Agreement contract. I do not expect the upgrade to be reflected until the 2008 NWPP study is released.

Q. How have you accounted for the Cabinet Unit 4 upgrade in the pro forma?

A. The Cabinet Unit 4 upgrade is expected to generate 1.1 average megawatts of additional energy in an average water year. To account for this energy amount in the pro forma, the unit size is increased from 59.4 MW to 69.4 MW. The Dispatch Model then generates at the upgraded energy and capacity levels when it dispatches Cabinet Unit 4.

Q. Please explain how the upgrades to Colstrip Units 3 and 4 are reflected in the Dispatch Model.

A. The Company increased the generation capability of each unit from 740 MW to 768 MW. This change allows the Dispatch Model to correctly value the entirety of each plant in the wholesale marketplace. Our resource portfolio tracked in the Dispatch Model contains 15 percent shares of each Colstrip Unit 3 and 4. With the overall capacity of each resource increased, our 15 percent allocation increases proportionally and lowers the overall cost of our generation portfolio.

III. LOAD FORECAST

Q. Company witness Mr. Norwood explains in his testimony that the Company is modeling net power supply expenses using 2007 pro forma loads. Will you please explain the source for this forecast?

A. Yes. Each year the Company develops a 25-year load forecast by rate class (residential, commercial, industrial, and street lighting). The load forecast is used by many departments throughout the Utility. It is the basis for power supply budgeting, revenue forecasting by our finance department, and for our Integrated Resource Plans (IRPs). During the natural gas and electric IRP processes the forecast is reviewed internally by senior management as well as by external parties including Washington, Idaho and Oregon Commission staff members.

The basis of this case is the Company's 2007 load forecast, which was finalized in July 2006. The 2007 load forecast value is 1,091 aMW. As the pro forma load forecast for 2007 is generated using "normal weather," using forecasted pro forma loads eliminates the need for a weather-normalization adjustment.

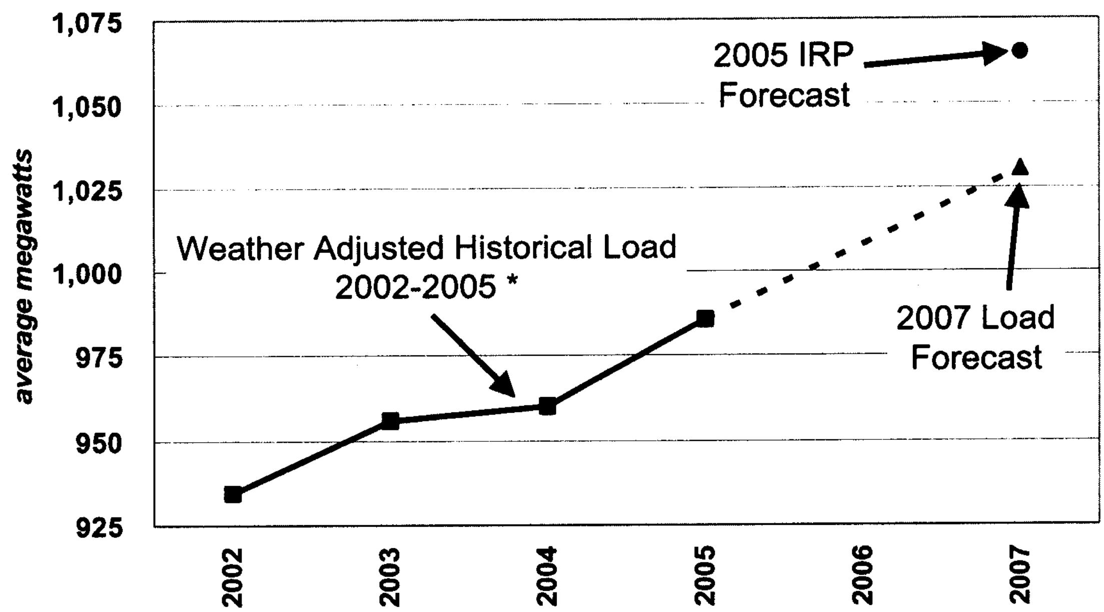
Q. What is the Company's present loads and resources position?

A. The Company's latest energy and capacity loads and resources tabulations (L&Rs) are attached as Exhibit No.___(CGK-2). As the L&Rs show, 2007 loads are expected to equal 1,091 aMW. This figure is reduced by 60 aMW of self-generation by the Potlatch Corporation, a large industrial customer load located in Idaho. This adjustment lowers the pro forma forecast to 1,031 aMW.

Q. How does the forecast load value compare with recent results?

A. Illustration No. 1 shows historical and forecasted utility load changes. As the table illustrates, our 2007 forecast of retail load follows a trend line consistent with recent history.

Illustration No. 1—Historical and Forecast System Loads



* 2005 represents the last full calendar year where actual retail load figures are available

Q. Does the current load forecast differ from the 2005 Integrated Resource Plan forecast?

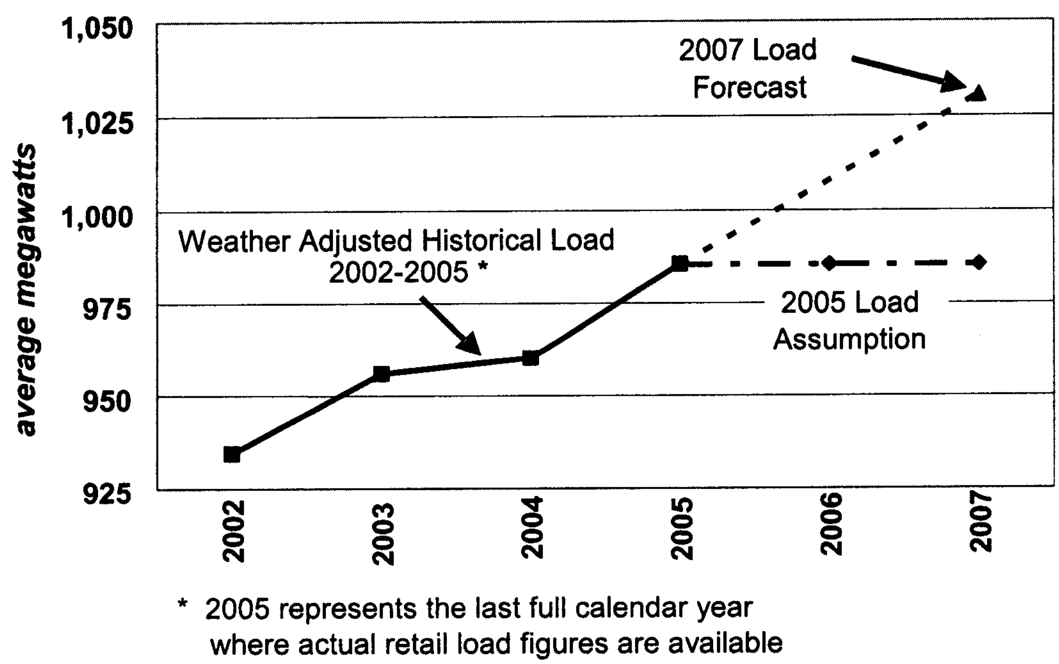
A. Yes. The 2005 IRP forecast, completed in mid-2004, estimated 2007 native load at 1,065 aMW. This is approximately 35 aMW higher than our current forecast. The current forecast uses the latest trends in load, including two additional years of actual history. The 2005 IRP forecast is provided in Illustration No. 1 for comparison to today's forecast.

Q. What is the significance of using the forecasted pro forma load estimate for ratemaking purposes?

A. Mr. Norwood explained in his testimony how pro forma 2007 retail loads provide a better matching of revenues and expenses during the period that new rates will be in effect (2007). In addition, the continuing high cost to serve growing retail load has a major impact on the Company's revenue requirement; load growth is a major driver of revenue requirement.

Illustration No. 2 builds on information presented in Illustration No. 1. It shows the inappropriateness of using 2005 loads to set rates for calendar year 2007—using 2005 actual loads would assume the Company will experience <u>no load growth for two calendar years.</u> This would be at odds with recent history and any reasonable load growth assumption, especially given the robust economy in our Company's service area.

<u>Illustration No. 2 – Pro Forma Load Forecast Comparison</u>



The use of historical, outdated, retail loads will result in an understatement of resource costs to serve the higher loads, as well as an understatement of retail revenues resulting from such loads.

Q. How does a difference between the pro forma and actual loads get tracked today?

A. As explained more fully by Mr. Johnson, when actual 2007 loads differ from the pro forma, the difference between the two values is tracked through the ERM, with additional or reduced sales being adjusted through the Retail Revenue Credit. The use of 2007 pro forma loads in this case will result in much smaller differences in the ERM Retail Revenue Credit, as compared to the use of 2005 pro forma loads. In other words, <u>2007 loads provide a more accurate basis to set retail rates.</u>

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, which are contained in Exhibit No. ___(CGK-3), are 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.

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EXHIBIT NO.___(CGK-2)

CLINT G. KALICH

REPRESENTING AVISTA CORPORATION

Exhibit 2
Avista Utilities Loads and Resources Position – Energy Tabulation

Last Updated July 28, 2006	Notes	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
AVERAGE LOAD & HYDRO PLANNING											
REQUIREMENTS											
System Load	1	(1,091)	(1,124)	(1,161)	(1,194)	(1,226)	(1,252)	(1,270)	(1,302)	(1,321)	(1,354)
Contract Obligations	2	(61)	(61)	(61)	(60)	(60)	(59)	(59)	(59)	(59)	(59)
Total Requirements		(1,152)	(1,185)	(1,222)	(1,254)	(1,286)	(1,311)	(1,329)	(1,361)	(1,380)	(1,413)
RESOURCES											
Contract Rights	4	284	283	284	283	178	160	161	155	153	153
Hydro	3	539	540	538	531	528	512	511	510	510	509
Base Load Thermals	5	229	243	228	232	242	231	230	243	231	230
Gas Dispatch Units	6	294	279	294	284	294	279	294	284	295	279
Total Resources		1,346	1,346	1,343	1,330	1,242	1,183	1,196	1,194	1,189	1,172
POSITION		**194**	**161**	**122**	**76**	**(44)**	**(129)**	**(133)**	**(167)**	**(191)**	**(241)**
CONTINGENCY PLANNING											
Confidence Interval	7	(167)	(167)	(166)	(163)	(162)	(159)	(159)	(159)	(159)	(159)
WNP-3 Obligation	8	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)
Peaking Resources	9	145	145	145	141	146	145	144	146	146	142
CONTINGENCY NET POSITION		**140**	**106**	**67**	**21**	**(94)**	**(175)**	**(181)**	**(214)**	**(237)**	**(291)**

Notes:

1. Load estimates are from the 2007 load forecast (6-27-2006) including 100% of Potlatch load
2. Includes Nichols Pumping and Canadian Entitlement Return contracts. Does not include WNP-3 Obligation.
3. Median (70-year) hydro generation for system hydro (Clark Fork and Spokane River projects) and contract hydro (Mid-Columbia) based on NWPP, includes Hydro Upgrades 2004-05 Headwater Benefits Study, modified for daily spill. Mid-C numbers reflect the Priest Rapids and Wanapum contract extensions beginning in 2005.
4. Includes small PURPA contracts, Upriver, El Paso 2004-2006 25 MW flat, Duke 2004-2006 50 MW flat, Morgan Stanley 2004-2006 25 MW flat, El Paso 2007-2010 75 MW flat, BP Energy 2007-2010 25 MW flat, Grant Displacement, PPM Wind, Potlatch self generation, and WNP-3 Receipt.
5. Includes Colstrip and Kettle Falls at full capability, adjusted for maintenance and forced outage.
6. Includes Coyote Springs 2, Coyote Springs 2 duct burner, Boulder Park, and Kettle Falls CT at full capability, adjusted for maintenance and forced outage.
7. The confidence interval represents the 12-month average of reserve energy necessary to ensure no more than a 10% probability of loads exceeding, and/or hydro underperforming, during a given month.
8. Represents highest level of potential obligation to BPA generally exercised under low hydro conditions.
9. Includes Northeast and Rathdrum at full capability, adjusted for forced outage and maintenance.
   Northeast is limited to 1,700 hours of operation per year, which has been applied to the period of highest typical market prices.

Exhibit 2
Avista Utilities Loads and Resources Position – Capacity Tabulation

Last Updated July 13, 2006	Notes	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
PEAK LOAD AND RESOURCE PLANNING											
REQUIREMENTS											
Native Load	1	(1,656)	(1,707)	(1,761)	(1,812)	(1,864)	(1,904)	(1,933)	(1,983)	(2,013)	(2,064)
Contracts Obligations	2	(169)	(169)	(169)	(168)	(168)	(166)	(165)	(165)	(165)	(165)
Total Requirements		(1,824)	(1,876)	(1,930)	(1,980)	(2,031)	(2,070)	(2,098)	(2,148)	(2,178)	(2,229)
RESOURCES											
Contracts Rights	3	329	329	329	329	229	212	212	212	212	212
Hydro Resources	4	1,132	1,142	1,154	1,121	1,128	1,084	1,098	1,098	1,098	1,098
Base Load Thermals	5	276	280	280	280	280	280	280	280	280	280
Gas Dispatch Units	6	308	308	308	308	308	308	308	308	308	308
Peaking Units	7	243	243	243	243	243	243	243	243	243	243
Total Resources		2,287	2,301	2,313	2,280	2,187	2,126	2,140	2,140	2,140	2,140
PEAK POSITION		**463**	**425**	**383**	**300**	**156**	**56**	**42**	**(9)**	**(38)**	**(90)**
RESERVE PLANNING											
Planning Reserve Margin	8	(256)	(261)	(266)	(271)	(276)	(280)	(283)	(288)	(291)	(296)
RESERVE PEAK POSITION		**207**	**164**	**117**	**29**	**(120)**	**(224)**	**(241)**	**(297)**	**(330)**	**(386)**

Notes:

Because Avista Utilities' load peaks in the winter, all data is based on monthly peak deficits from period November through February.

1. Load estimates are from the 2007 peak load forecast (6-27-2006) including the forecast of Potlatch load.
2. Includes Nichols Pumping, Canadian Entitlement Return, and PGE Capacity contracts.
3. Includes small PURPA contracts, Upriver, El Paso 2004-2006 25 MW flat, Duke 2004-2006 50 MW flat, Morgan Stanley 2004-2006 25 MW flat, El Paso 2007-2010 75 MW flat, BP Energy 2007-2010 25 MW flat, Grant Displacement, WNP-3 Receipt, and Potlatch generation.
4. Peak hydro generation for system hydro (Clark Fork and Spokane River projects, excluding maintenance) and contract hydro (Mid-Columbia, including maintenance). Mid-C numbers reflect the Priest Rapids and Wanapum contract extensions beginning in 2005.
5. Includes Colstrip and Kettle Falls, maintenance is assumed to occur outside the November through February timeframe.
6. Includes 100% of Coyote Springs 2 and Coyote Springs 2 duct burner, Boulder Park, and Kettle Falls CT; maintenance is assumed to occur outside the November through February timeframe.
7. Includes Northeast and Rathdrum, maintenance is assumed to occur outside the November through February timeframe.
8. Includes 10% of peak load (to approximate load variability) and 90 MW (to approximate the risk of river freeze-up and partial forced outages).

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EXHIBIT NO.___(CGK-3)

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Exhibit 3
AURORA Summary Output—Project Generation (GWh)

	Ann	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hydro Projects													
Clark Fork	2,844.5	170.5	184.4	172.0	280.7	467.2	467.2	330.3	189.0	134.0	121.3	111.6	216.2
Cabinet Gorge	927.5	55.6	60.1	56.1	91.5	152.3	152.3	107.7	61.6	43.7	39.6	36.4	70.5
Noxon Rapids	1,917.0	114.9	124.3	115.9	189.1	314.9	314.9	222.6	127.4	90.3	81.8	75.2	145.7
TOTAL	***2,844.5***	***170.5***	***184.4***	***172.0***	***280.7***	***467.2***	***467.2***	***330.3***	***189.0***	***134.0***	***121.3***	***111.6***	***216.2***
Spokane River	1,134.1	103.8	101.6	123.0	122.3	126.5	114.9	76.7	40.5	60.8	74.1	89.8	100.1
Little Falls	227.9	20.9	20.4	24.7	24.6	25.4	23.1	15.4	8.1	12.2	14.9	18.0	20.1
Long Lake	454.0	41.6	40.7	49.2	49.0	50.6	46.0	30.7	16.2	24.3	29.7	35.9	40.1
Monroe Street	93.8	8.6	8.4	10.2	10.1	10.5	9.5	6.3	3.4	5.0	6.1	7.4	8.3
Nine Mile	179.8	16.5	16.1	19.5	19.4	20.1	18.2	12.2	6.4	9.6	11.8	14.2	15.9
Post Falls	114.0	10.4	10.2	12.4	12.3	12.7	11.5	7.7	4.1	6.1	7.4	9.0	10.1
Upper Falls	64.6	5.9	5.8	7.0	7.0	7.2	6.5	4.4	2.3	3.5	4.2	5.1	5.7
TOTAL	***1,134.1***	***103.8***	***101.6***	***123.0***	***122.3***	***126.5***	***114.9***	***76.7***	***40.5***	***60.8***	***74.1***	***89.8***	***100.1***
Mid-Columbia- Contracts	628.5	72.0	54.5	50.3	53.7	50.5	56.4	54.0	46.4	37.3	44.1	50.1	59.2
Priest Rapids	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rocky Reach	158.2	18.1	13.7	12.7	13.5	12.7	14.2	13.6	11.7	9.4	11.1	12.6	14.9
Wanapum	344.8	39.5	29.9	27.6	29.4	27.7	30.9	29.7	25.4	20.5	24.2	27.5	32.5
Wells	125.4	14.4	10.9	10.0	10.7	10.1	11.3	10.8	9.3	7.4	8.8	10.0	11.8
TOTAL	***628.5***	***72.0***	***54.5***	***50.3***	***53.7***	***50.5***	***56.4***	***54.0***	***46.4***	***37.3***	***44.1***	***50.1***	***59.2***
TOTAL	***4,607.1***	***346.3***	***340.5***	***345.3***	***456.6***	***644.3***	***638.5***	***461.1***	***275.9***	***232.1***	***239.5***	***251.5***	***375.4***
Thermals													
Boulder Park	26.4	2.0	2.3	2.1	2.4	1.4	0.7	1.0	2.5	2.8	2.9	3.3	3.0
Colstrip	1,604.9	150.4	137.7	140.3	96.7	81.9	96.4	130.7	157.1	152.8	155.8	151.7	153.5
Coyote Springs 2	1,390.5	146.7	119.6	116.6	92.3	40.8	57.2	90.6	142.3	152.1	146.4	138.0	147.9
Kettle Falls	376.3	33.4	30.2	33.3	32.2	33.2	15.5	33.3	33.5	32.4	33.5	32.4	33.5
Kettle Falls CT	1.1	0.2	0.2	0.0	0.1	0.0	0.0	0.0	0.2	0.1	0.0	0.0	0.1
Northeast	3.6	0.6	0.7	0.2	0.3	0.1	0.1	0.1	0.3	0.2	0.3	0.2	0.6
Rathdrum	51.3	5.3	5.4	2.9	4.6	2.3	1.1	1.6	4.7	4.7	5.4	6.0	7.3
TOTAL	***3,454.1***	***338.6***	***296.1***	***295.4***	***228.8***	***159.8***	***171.0***	***257.2***	***340.5***	***345.2***	***344.2***	***331.6***	***345.8***
RESOURCE TOTAL	***8,061.2***	***684.8***	***636.6***	***640.7***	***685.4***	***804.0***	***809.5***	***718.3***	***616.4***	***577.4***	***583.8***	***583.1***	***721.2***
Contracts													
Black Creek	8.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.2	0.0	0.0
DOPD	31.8	1.8	1.7	2.1	3.4	4.7	4.5	3.3	2.7	1.7	2.0	1.9	1.9
Market Contract 1	219.0	18.6	16.8	18.6	18.0	18.6	18.0	18.6	18.6	18.0	18.6	18.0	18.6
Can Ent Return	(41.8)	(3.7)	(3.3)	(3.7)	(3.3)	(3.6)	(3.4)	(3.4)	(3.6)	(3.3)	(3.6)	(3.4)	(3.4)
Grant County	123.9	14.8	11.3	10.3	10.6	8.4	8.6	10.8	9.6	7.7	9.1	10.4	12.2
Jim White	1.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.1	0.1	0.1
Market Contract 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Market Contract 3	657.0	55.8	50.4	55.8	54.0	55.8	54.0	55.8	55.8	54.0	55.8	54.0	55.8
Grant Displacement	194.1	12.9	11.8	13.2	18.9	23.7	22.8	20.5	14.7	13.7	13.9	13.8	14.3
Haleywest	37.7	3.2	2.9	3.2	3.1	3.2	3.1	3.2	3.2	3.1	3.2	3.1	3.2
Jim Ford Creek	6.1	0.6	0.6	0.7	0.7	0.8	0.7	0.5	0.2	0.2	0.3	0.3	0.5
John Day Creek	4.0	0.4	0.4	0.5	0.5	0.5	0.4	0.3	0.2	0.1	0.2	0.2	0.3
Meyers Falls	5.2	0.5	0.5	0.6	0.6	0.7	0.6	0.4	0.2	0.2	0.2	0.3	0.4
Nichols Pumping	(70.1)	(6.0)	(5.4)	(6.0)	(5.8)	(6.0)	(5.8)	(6.0)	(6.0)	(5.8)	(6.0)	(5.8)	(6.0)
PGE CapExch	0.6	0.9	(0.5)	(0.3)	1.2	(1.6)	1.2	0.6	(0.9)	1.1	(0.0)	(0.7)	(0.3)
Phillips Ranch	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Potlatch	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind Contract	66.2	6.6	4.2	6.3	5.3	6.4	6.8	5.3	6.4	5.7	5.8	4.7	2.7
Reserves	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sheep Creek	6.9	0.4	0.3	0.7	1.1	1.1	1.1	0.8	0.3	0.2	0.2	0.3	0.4
Upriver	42.6	5.0	5.7	7.2	7.1	7.4	4.3	1.0	(1.1)	0.3	0.9	1.4	3.3
WNP3	319.5	66.0	59.6	32.6	31.6	0.0	0.0	0.0	0.0	0.0	0.0	63.8	66.0
Thompson River Co-Gen	87.6	8.0	7.2	7.8	6.9	6.0	4.1	7.0	8.3	8.1	8.3	7.9	8.1
TOTAL	***1,699.7***	***185.9***	***164.4***	***149.6***	***153.9***	***126.3***	***120.9***	***118.9***	***108.6***	***105.3***	***117.3***	***170.4***	***178.2***
Market Transactions													
Market Purchases	522.1	78.0	32.9	63.3	8.7	3.5	4.4	33.7	77.5	49.4	71.7	39.7	59.4
Market Sales	(1,250.8)	(49.1)	(70.4)	(44.7)	(167.3)	(257.7)	(268.4)	(129.5)	(35.7)	(59.7)	(26.1)	(54.4)	(87.8)
TOTAL	***(728.7)***	***28.9***	***(37.5)***	***18.6***	***(158.5)***	***(254.3)***	***(263.9)***	***(95.8)***	***41.8***	***(10.3)***	***45.6***	***(14.8)***	***(28.4)***

Exhibit 3
AURORA Summary Output—Project Generation (aMW)

	Ann	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hydro Projects													
Clark Fork	324.7	229.1	274.5	231.2	389.3	628.0	648.9	443.9	254.0	186.2	163.3	155.0	290.5
Cabinet Gorge	105.9	74.7	89.5	75.4	126.9	204.8	211.6	144.7	82.8	60.7	53.2	50.6	94.7
Noxon Rapids	218.8	154.4	185.0	155.8	262.3	423.2	437.3	299.2	171.2	125.5	110.1	104.5	195.8
TOTAL (aMW)	***324.7***	***229.1***	***274.5***	***231.2***	***389.3***	***628.0***	***648.9***	***443.9***	***254.0***	***186.2***	***163.3***	***155.0***	***290.5***
Spokane River	129.5	139.6	151.2	165.3	169.6	170.1	159.5	103.1	54.5	84.4	99.8	124.7	134.6
Little Falls	26.0	28.0	30.4	33.2	34.1	34.2	32.1	20.7	10.9	17.0	20.0	25.1	27.0
Long Lake	51.8	55.9	60.5	66.2	67.9	68.1	63.9	41.3	21.8	33.8	39.9	49.9	53.9
Monroe Street	10.7	11.5	12.5	13.7	14.0	14.1	13.2	8.5	4.5	7.0	8.3	10.3	11.1
Nine Mile	20.5	22.1	24.0	26.2	26.9	27.0	25.3	16.4	8.6	13.4	15.8	19.8	21.3
Post Falls	13.0	14.0	15.2	16.6	17.0	17.1	16.0	10.4	5.5	8.5	10.0	12.5	13.5
Upper Falls	7.4	7.9	8.6	9.4	9.7	9.7	9.1	5.9	3.1	4.8	5.7	7.1	7.7
TOTAL (aMW)	***129.5***	***139.6***	***151.2***	***165.3***	***169.6***	***170.1***	***159.5***	***103.1***	***54.5***	***84.4***	***99.8***	***124.7***	***134.6***
Mid-Columbia- Contracts	71.7	96.8	81.1	67.6	74.4	67.9	78.3	72.6	62.3	51.8	59.3	69.6	79.5
Priest Rapids	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rocky Reach	18.1	24.4	20.4	17.0	18.7	17.1	19.7	18.3	15.7	13.1	14.9	17.5	20.0
Wanapum	39.4	53.1	44.5	37.1	40.8	37.3	43.0	39.9	34.2	28.4	32.6	38.2	43.6
Wells	14.3	19.3	16.2	13.5	14.9	13.5	15.6	14.5	12.4	10.3	11.8	13.9	15.9
TOTAL (aMW)	***71.7***	***96.8***	***81.1***	***67.6***	***74.4***	***67.9***	***78.3***	***72.6***	***62.3***	***51.8***	***59.3***	***69.6***	***79.5***
TOTAL	***525.9***	***465.4***	***506.7***	***464.2***	***633.3***	***866.0***	***886.8***	***619.7***	***370.8***	***322.4***	***322.4***	***349.4***	***504.6***
Thermals													
Boulder Park	3.0	2.7	3.4	2.8	3.4	1.9	1.0	1.3	3.4	3.9	3.9	4.6	4.0
Colstrip	183.2	202.1	204.9	188.5	134.1	110.1	133.9	175.7	211.1	212.2	209.7	210.7	206.3
Coyote Springs 2	158.7	197.2	178.0	156.7	128.1	54.9	79.5	121.8	191.2	211.3	197.1	191.6	198.7
Kettle Falls	43.0	44.9	44.9	44.8	44.7	44.6	21.5	44.7	45.0	45.1	45.0	44.9	45.0
Kettle Falls CT	0.1	0.3	0.3	0.0	0.2	0.0	0.0	0.0	0.2	0.1	0.1	0.0	0.1
Northeast	0.4	0.7	1.0	0.2	0.5	0.2	0.1	0.1	0.4	0.3	0.3	0.3	0.8
Rathdrum	5.9	7.1	8.0	4.0	6.4	3.1	1.5	2.1	6.3	6.5	7.2	8.3	9.8
TOTAL	***394.3***	***455.1***	***440.6***	***397.0***	***317.3***	***214.8***	***237.6***	***345.7***	***457.6***	***479.5***	***463.3***	***460.5***	***464.7***
RESOURCE TOTAL	***920.2***	***920.5***	***947.3***	***861.2***	***950.6***	***1,080.7***	***1,124.3***	***965.4***	***828.4***	***801.9***	***785.7***	***809.9***	***969.4***
Contracts													
Black Creek	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.0	0.0	0.0
DOPD	3.6	2.4	2.6	2.8	4.7	6.3	6.2	4.5	3.7	2.4	2.7	2.7	2.6
Market Contract 1	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
Can Ent Return	(4.8)	(5.0)	(4.9)	(5.0)	(4.6)	(4.8)	(4.8)	(4.6)	(4.8)	(4.6)	(4.8)	(4.8)	(4.6)
Grant County	14.1	19.9	16.8	13.9	14.7	11.3	11.9	14.5	12.9	10.7	12.3	14.4	16.4
Jim White	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1
Market Contract 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Market Contract 3	75.0	75.0	75.0	75.0	74.9	75.0	75.0	75.0	75.0	75.0	75.1	75.0	75.0
Grant Displacement	22.2	17.4	17.6	17.7	26.2	31.8	31.6	27.6	19.7	19.0	18.7	19.2	19.2
Haleywest	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
Jim Ford Creek	0.7	0.8	0.9	1.0	1.0	1.0	0.9	0.6	0.3	0.3	0.4	0.5	0.7
John Day Creek	0.5	0.5	0.6	0.6	0.7	0.7	0.6	0.4	0.2	0.2	0.3	0.3	0.4
Meyers Falls	0.6	0.7	0.8	0.8	0.9	0.9	0.8	0.5	0.3	0.3	0.3	0.4	0.6
Nichols Pumping	(8.0)	(8.0)	(8.0)	(8.0)	(8.0)	(8.0)	(8.0)	(8.0)	(8.0)	(8.0)	(8.0)	(8.0)	(8.0)
PGE CapExch	0.1	1.2	(0.7)	(0.5)	1.7	(2.1)	1.6	0.8	(1.2)	1.6	(0.1)	(1.0)	(0.3)
Phillips Ranch	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Potlatch	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind Contract	7.6	8.9	6.3	8.5	7.3	8.6	9.4	7.1	8.6	7.9	7.8	6.5	3.7
Reserves	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sheep Creek	0.8	0.5	0.5	0.9	1.5	1.5	1.5	1.1	0.3	0.3	0.3	0.5	0.5
Upriver	4.9	6.7	8.5	9.7	9.8	10.0	6.0	1.4	(1.5)	0.5	1.3	1.9	4.4
WNP3	36.5	88.6	88.6	43.8	43.8	0.0	0.0	0.0	0.0	0.0	0.0	88.6	88.6
Thompson River Co-Gen	10.0	10.7	10.7	10.5	9.5	8.1	5.6	9.4	11.1	11.3	11.1	11.0	10.9
TOTAL	***194.0***	***249.9***	***244.6***	***201.1***	***213.5***	***169.8***	***168.0***	***159.8***	***146.0***	***146.2***	***157.8***	***236.6***	***239.5***
	0.0	0.0	0.0	0.0	(0.0)	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0
Market Transactions													
Market Purchases	59.6	104.9	48.9	85.1	12.1	4.7	6.2	45.3	104.1	68.6	96.5	55.1	79.8
Market Sales	(142.8)	(66.0)	(104.7)	(60.1)	(232.0)	(346.4)	(372.8)	(174.1)	(48.0)	(82.9)	(35.2)	(75.6)	(118.0)
TOTAL	***(83.2)***	***38.8***	***(55.8)***	***25.0***	***(219.9)***	***(341.7)***	***(366.6)***	***(128.8)***	***56.1***	***(14.3)***	***61.3***	***(20.5)***	***(38.2)***

Exhibit 3
AURORA Summary Output—Project Costs ($000s)

		Ann	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hydro Projects														
Clark Fork		0	0	0	0	0	0	0	0	0	0	0	0	0
Cabinet Gorge		0	0	0	0	0	0	0	0	0	0	0	0	0
Noxon Rapids		0	0	0	0	0	0	0	0	0	0	0	0	0
	TOTAL	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
Spokane River		0	0	0	0	0	0	0	0	0	0	0	0	0
Little Falls		0	0	0	0	0	0	0	0	0	0	0	0	0
Long Lake		0	0	0	0	0	0	0	0	0	0	0	0	0
Monroe Street		0	0	0	0	0	0	0	0	0	0	0	0	0
Nine Mile		0	0	0	0	0	0	0	0	0	0	0	0	0
Post Falls		0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Falls		0	0	0	0	0	0	0	0	0	0	0	0	0
	TOTAL	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
Mid-Columbia- Contracts		6,793	566	566	566	566	566	566	566	566	566	566	566	566
Priest Rapids		0	0	0	0	0	0	0	0	0	0	0	0	0
Rocky Reach		1,964	164	164	164	164	164	164	164	164	164	164	164	164
Wanapum		3,622	302	302	302	302	302	302	302	302	302	302	302	302
Wells		1,206	101	101	101	101	101	101	101	101	101	101	101	101
	TOTAL	*6,793*	*566*	*566*	*566*	*566*	*566*	*566*	*566*	*566*	*566*	*566*	*566*	*566*
	TOTAL	*6,793*	*566*	*566*	*566*	*566*	*566*	*566*	*566*	*566*	*566*	*566*	*566*	*566*
Thermals														
Boulder Park		2,186	185	207	185	184	106	53	73	195	221	227	280	268
Colstrip		14,834	1,390	1,273	1,296	894	757	891	1,208	1,452	1,412	1,440	1,402	1,419
Coyote Springs 2		89,178	10,254	8,463	8,160	5,592	2,413	3,435	5,371	8,407	9,002	8,840	8,942	10,298
Kettle Falls		10,216	830	758	872	889	925	433	927	927	903	937	902	913
Kettle Falls CT		88	20	17	3	11	3	1	3	12	7	3	2	8
Northeast		434	71	91	19	38	14	5	7	35	27	28	25	74
Rathdrum		5,418	608	622	333	444	218	105	154	457	464	536	636	841
	TOTAL	*122,355*	*13,359*	*11,431*	*10,868*	*8,051*	*4,435*	*4,924*	*7,743*	*11,486*	*12,036*	*12,011*	*12,189*	*13,821*
	RESOURCE TOTAL	*122,355*	*13,359*	*11,431*	*10,868*	*8,051*	*4,435*	*4,924*	*7,743*	*11,486*	*12,036*	*12,011*	*12,189*	*13,821*
			27											
Contracts														
Black Creek		483	0	0	0	0	0	0	0	0	0	483	0	0
DOPD		833	46	45	53	88	122	116	86	71	47	53	52	53
Market Contract 1		7,556	642	580	642	621	642	621	642	642	621	642	621	642
Can Ent Return		0	0	0	0	0	0	0	0	0	0	0	0	0
Grant County		6,800	926	679	575	507	311	292	426	578	486	544	659	817
Jim White		76	8	8	9	9	10	8	6	3	3	4	4	6
Market Contract 2		0	0	0	0	0	0	0	0	0	0	0	0	0
Market Contract 3		20,192	1,715	1,549	1,715	1,660	1,715	1,660	1,715	1,715	1,660	1,715	1,660	1,715
Grant Displacement		5,823	388	355	395	566	710	683	616	440	410	417	415	429
Haleywest		2,024	186	168	144	140	144	140	186	186	180	186	180	186
Jim Ford Creek		368	53	52	30	31	32	28	27	14	13	17	28	42
John Day Creek		179	27	27	15	15	16	14	11	6	5	7	14	21
Meyers Falls		257	30	28	36	28	27	21	19	11	10	13	14	22
Nichols Pumping		(4,307)	(435)	(388)	(384)	(317)	(234)	(185)	(274)	(410)	(411)	(399)	(413)	(457)
PGE CapExch		4,159	604	396	375	731	68	239	274	27	430	326	237	452
Phillips Ranch		5	1	1	1	1	0	0	0	0	0	0	0	1
Potlatch		0	0	0	0	0	0	0	0	0	0	0	0	0
Wind Contract		2,510	250	159	239	199	243	258	201	243	216	220	178	103
Reserves		0	0	0	0	0	0	0	0	0	0	0	0	0
Sheep Creek		271	24	19	33	29	21	30	33	11	10	11	21	27
Upriver		1,619	220	251	246	242	253	147	46	(49)	15	42	60	146
WNP3		11,402	2,354	2,126	1,164	1,126	0	0	0	0	0	0	2,278	2,354
Thompson River Co-Gen		4,861	443	397	432	380	334	226	389	460	452	460	440	448
	TOTAL	*71,903*	*8,046*	*7,017*	*6,285*	*6,621*	*4,981*	*4,862*	*4,969*	*4,513*	*4,714*	*5,308*	*7,016*	*7,571*
		(6,793)	(566)	(566)	(566)	(566)	(566)	(566)	(566)	(566)	(566)	(566)	(566)	(566)
Market Transactions														
Market Purchases		36,864	5,420	2,373	4,629	400	159	177	1,740	5,385	3,602	5,112	3,205	4,659
Market Sales		(67,476)	(3,983)	(5,446)	(2,791)	(9,481)	(10,128)	(10,089)	(5,668)	(2,464)	(4,546)	(1,779)	(4,044)	(7,058)
	TOTAL	*(30,613)*	*1,437*	*(3,073)*	*1,838*	*(9,081)*	*(9,969)*	*(9,912)*	*(3,928)*	*2,921*	*(944)*	*3,333*	*(838)*	*(2,399)*
Fuel and Market Only		91,743	14,796	8,358	12,706	(1,029)	(5,534)	(4,988)	3,815	14,407	11,092	15,345	11,351	11,423
Coyote Adjustment		*1,909*	*241*	*195*	*205*	*37*	*16*	*24*	*111*	*175*	*186*	*181*	*247*	*291*