

**AVISTA<sup>®</sup>**

***Corp.***

# 2001 Electric Integrated Resource Plan



COYOTE SPRINGS II SITE

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# PLAN SUMMARY

## Introduction

July 12,  
2000  
Avista  
filed an  
updated  
1997  
IRP

Avista Corp.'s last Integrated Resource Plan (IRP) was filed with the Commission on August 25, 1997. Since then many things have changed in the electric utility industry and for Avista Utilities, the regulated division of Avista Corp.

On July 12, 2000 Avista prepared an update to its 1997 IRP to include those significant changes. This updated IRP also served as the basis for a Request-For-Proposals (RFP), which was issued on August 14, 2000.

Since then, there have been other updates including the final results of the RFP process. These updates show significant peak and energy deficits for the company starting in the year 2004, without additional resources.

## Resource Update

1. On February 12, 1999 Avista sold Meyers Falls, a small hydroelectric project to Hydro Technology Systems.
2. In 1999, the company completed the program to replace all four runners at Long Lake hydro facility, which increased the capability from 72.8 MW to 88 MW.
3. On February 23, 2000 the Federal Energy Regulatory Commission issued to Avista a new 45-year operating license for the two hydroelectric projects on the Clark Fork River.
4. On May 5, 2000 the sale of Centralia, a coal-fired generating facility, to TransAlta was completed. Avista owned 15% of the generating plant. Generation was replaced with a purchase through 2003.
5. Cabinet Gorge upgrades are in progress for a total increase of 52 MW with 9aMW of energy.
6. Avista has selected the 280 MW Coyote Springs II project and three DSM resources for a total of 13aMW to meet a large portion of its resource needs.

For further information, please see Appendix A.

## Electric Sales Forecast

The forecast of firm sales to the core-market is one of the most critical forecast elements. Customers in the core-market segment include residential, commercial and industrial. The requirements of the core-market segments place demand on the delivery system (both distribution and transmission) for which generation capacity is acquired, either by ownership or purchase contracts.

Avista utilizes econometric models to produce sales and customer forecasts. Peak load and energy forecasts are derived from the sales forecasts. The total sales forecast in kWh reflects a compound growth rate of 1.9%. The forecasted peak load for the year 2000 is 1557 MW and for the year 2009 is 1851 MW. The energy forecast for the year 2000 is 1008 aMW and for the year 2009 is 1159 aMW.

For further information, please refer to Appendix B.

## **Resource Planning**

Avista is projecting a modest but increasing load growth of 1.9 percent over the next ten years. These load increases over the planning period result in the need for additional resources. In addition the company's power purchase of 200 MW, which replaced Centralia generation, expires at the end of 2003. Also the company has recently experienced dramatic increases in market price and volatility, which has caused the company to move away from reliance on the short-term market for a portion of its base resources. These changes have caused the company to implement a resource acquisition strategy to serve its needs.

August  
14,  
2000  
Avista  
issued  
an RFP

Based on Avista's current load projections and resource requirements, the company is facing significant energy and peak deficits. By the year 2009 the peak deficit is 402 MW and the energy deficit is 301 aMW.

New resource(s) will have an impact on the resource dispatch sequence because of the fuel supply, marginal costs, and other operating characteristics. Avista is using PROSYM to model its resources to meet its system requirements on an hourly basis, and to assess the dispatch requirements and compatibility of new resource need in conjunction with existing resources, both hydro and thermal.

Avista issued an RFP in August 2000 to identify low cost and environmentally sound resource options that would best satisfy the company's resource needs. The bidding process supports the companies on going assessment of the cost and availability of new resources and provides input to this IRP.

For additional information, please see Appendix C and G.

## **Resource Alternatives**

There are multitudes of resource options available to the company. Some are more suitable than others depending on capital cost, dispatchability, accessibility, operating experience, environmental considerations, and other impacts. All resource options will be evaluated including energy efficiency measures.

Some of the options that have been discussed and are under consideration are:

1. Build a generating resource.
2. Purchase existing or new generation assets.

3. Complete system upgrades at generating facilities.
4. Negotiate a long-term power purchase agreement.
5. Buy in the short-term wholesale market.
6. Purchase the output of a generating or cogeneration facility.
7. Develop additional energy efficiency and DSM programs.
8. Buy energy efficiency through third party developers.

For further information refer to Appendix D.

### **Preferred Resource Strategy and 2001 Near-Term Action Plan**

**From the RFP process, Avista selected a CCCT and 3 DSM bids**

Avista was pleased with the number and variety of bids received in the RFP process. The quality of the proposals provided a good reflection of the market. Avista selected the 280 MW Coyote Springs II resource as a self-build project and three demand-side resource bids for a total of 13aMW.

Avista's preferred resource plan will be a combination of low-cost resource acquisitions. Avista expects to do the following:

1. Acquire supply and demand-side resources through the recently completed RFP process.
2. Continue or increase the level of energy efficiency programs, under the tariff rider.
3. Re-negotiation of mid-Columbia power purchase contracts.
4. Acquire hydro or thermal unit upgrades when cost-effective.
5. Purchase and sell on the short-term markets to match resource needs.
6. Evaluate and acquire, if cost-effective, additional supply and generation units to handle variability.

#### **2001 Near-Term Action Plan:**

##### Public Process

1. Continue free flowing exchange of information with TAC members.
2. Propose changes to the IRP process that will be useful in the competitive market era.

##### Demand-Side Management

1. Pursue energy savings for the next three years with funding from the tariff rider.
2. Consider the development of programs that will allow peak shaving.
3. Determine the potential for Time-Of-Use (TOU) rates.
4. Execute and implement DSM contracts that were selected under the 2000 RFP.

##### Supply-Side Resource Options

1. Pursue the base plan for Spokane River Hydro relicensing.
2. Upgrade at least two units at Cabinet Gorge hydro facility.
3. Evaluate the effects of a micro turbine on the system.

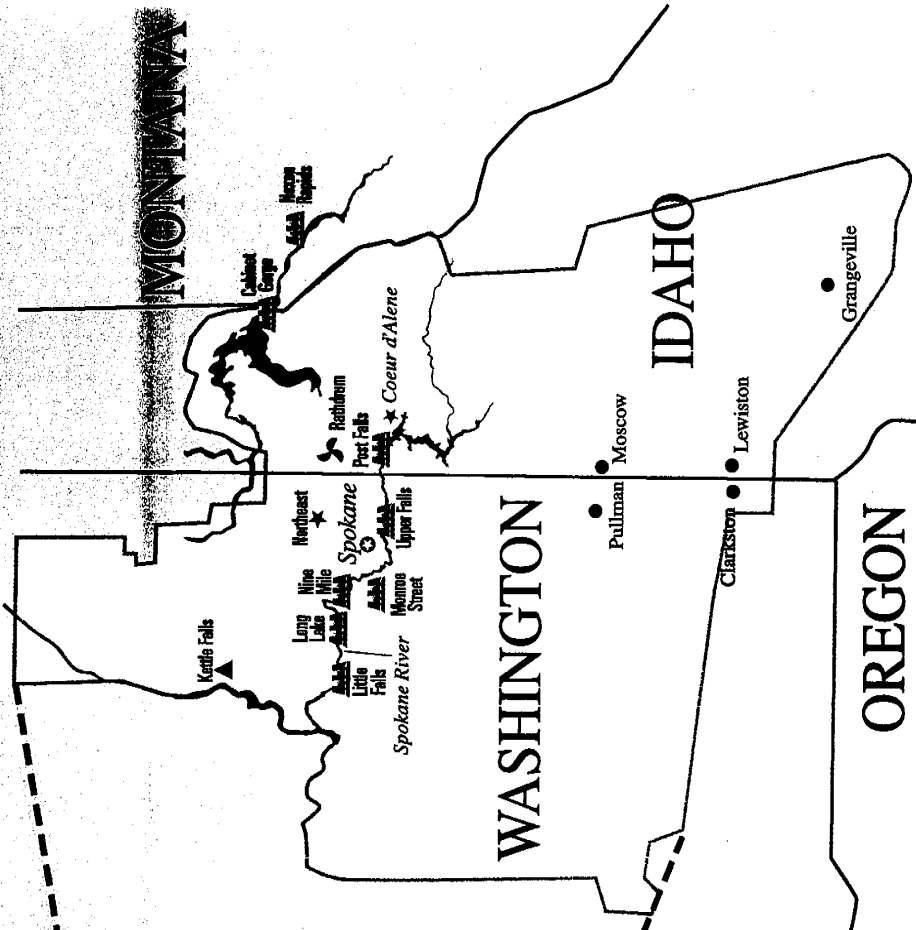
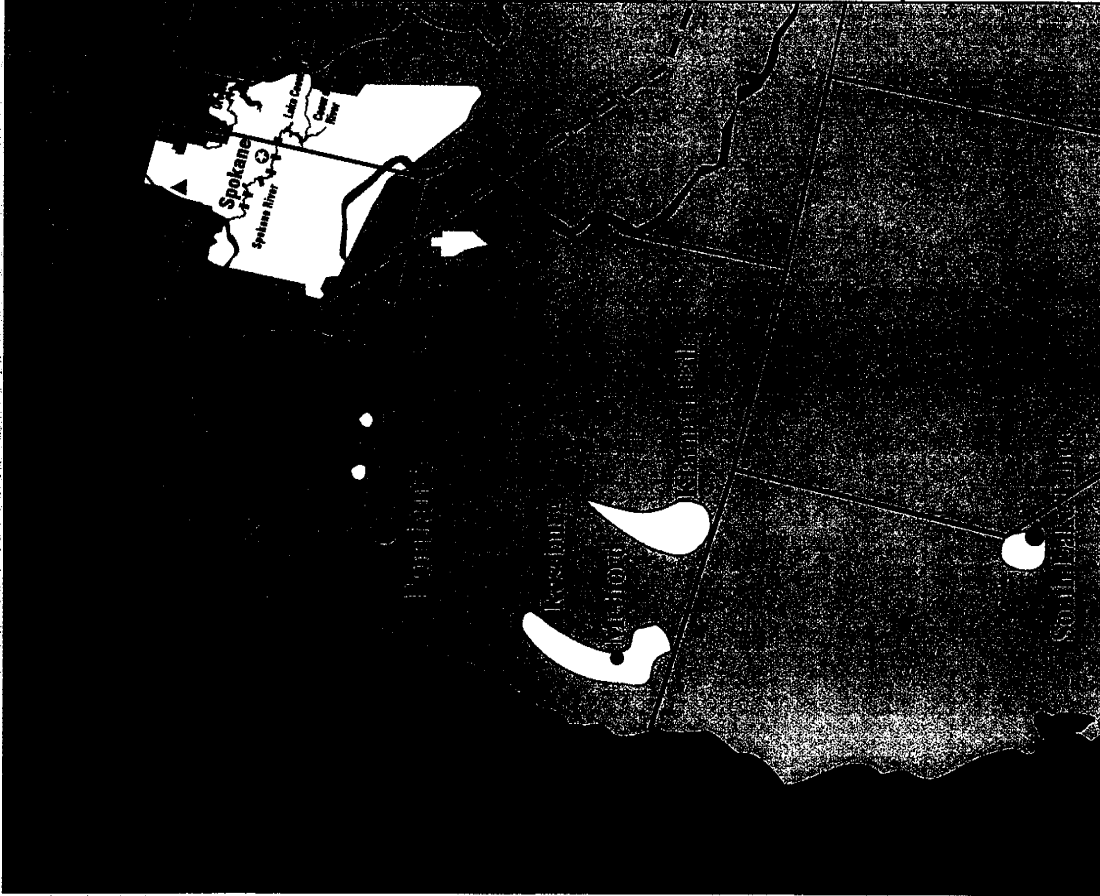
4. Installed inlet coolers at Rathdrum combustion turbines for additional summer peaking output (completed July, 2000).
5. Evaluated RFP bids, compared to company options, and selected options that were cost effective and that best met company's long-term resource need (completed December 2000). Complete transfer agreements for selected supply-side resource.
6. Pursue re-negotiation efforts with mid-Columbia PUDs.
7. Evaluate the need for additional supply or generation units to handle variability in hydro, retail loads, and potential generation outages under projected market conditions.

#### Resource Management Issues

1. Implement relicensing programs on the Clark Fork River hydro projects, as part of the "Living License" commitment.
2. Continue to examine and pursue cost-effective efficiency improvements at generation facilities.

For further information, please see Appendix E and F.

For more information about Avista Corp. or its affiliate businesses, visit the corporate website at [www.avistacorp.com](http://www.avistacorp.com).



- ☐ Avista Utility Service Territory
- ⊕ Corporate Headquarters—Spokane, Washington
- ⚡ Avista Utilities Hydroelectric Projects
- ▲ Kettle Falls Wood-Waste-Fueled Generating Station
- ⚙️ Rathdrum Combustion Turbine Generating Station
- ◆ Plymouth Liquefied Natural Gas Facility
- ✕ Jackson Prairie Underground Gas Storage Project
- Coyote Springs II Generating Station
- ★ Northeast Combustion Turbine Generating Station





# APPENDIX A

# 1997 ACTION PLAN





*Identify and pursue those opportunities that add value to the existing system and provide a positive resource benefit.*

Avista has added 4 to 5 aMW of DSM and conservation measures to its system each year. The company has reconstructed the intake at Monroe Street and can now realize full capacity output. We have also replaced the runners on all four units at Long Lake which provides a greater efficiency. With recent improvements to Kettle Falls we are now able to get a higher capacity rating , compared to one year ago.

## **Public Process**

*Continue to be involved with the public outreach programs through 1998 and beyond.*

Avista has been very successful in involving the public in its business decisions. Two examples of this is the Steam Plant oil cleanup in downtown Spokane and the collaborative relicensing process for the Noxon Rapids and Cabinet Gorge hydro facilities.

*Continue free flowing exchange of information with TAC members.*

The company feels that this has been accomplished through mailings and the holding of TAC meetings.

*Propose changes to the IRP process that will be useful in the competitive market era.*

Suggestions to improve the IRP process has been submitted both verbally and written that should be useful in this era of competition.

## **Demand-Side Management**

*Continue to pursue energy savings through the DSM filing for the next three years (1997-1999) with funding from the tariff rider.*

The DSM tariff rider has been granted an extension for the foreseeable future by both states, although in Idaho the funding has been reduced.

*Evaluate options to participate in regional, market transformation DSM programs.*

Avista is committed financially to support the region's market transformation programs.

## **Supply-Side Resource Options**

*Continue to pursue the most cost effective options in the hydro relicensing process.*

Avista was successful in preserving its hydro flexibility at Noxon and Cabinet Hydro facilities with a granting by FERC of a new 45 year operating license.

*Negotiate a favorable long-term Extension of the Wanapum and Priest rapids power sales contracts by December 1997.*

The company has not been successful to date in this action plan item. We still hope that some type of agreement can be reached with Grant PUD.

*Develop joint ventures with other*

Avista Labs is developing partnerships with

companies to market fuel cell technology.

others that can contribute to the product development and sales, such as Black & Veatch.

### **Resource Management Issues**

*Evaluate all resource options against wholesale market price of power.*

Avista uses market prices as a major input in its least-cost analysis as well as other considerations such as dispatchability, compatibility with existing resources and reliability. The company purchased third-party price forecasts for its RFP resource evaluations.

*Continue to evaluate the effects to hydroelectric system operation resulting from efforts to protect fish stocks listed under the ESA.*

The company is involved in helping the region mitigate effects from fish protection but the main concern is bull trout mitigation on the Clark Fork river. Avista through its new license has committed to funding mitigation efforts at Noxon and Cabinet hydro facilities. The "living" license concept allows changes in the approach to these mitigation efforts as future conditions dictate.

*Implement the best compliance strategy for the Centralia coal-fired plant.*

The company along with the other owners purchased scrubbers to bring the plant into compliance, prior to selling the plant.

*Implement FERC Orders 888 and 889 during 1997.*

The company has separated its marketing and transmission functions and has complied with all the details of the FERC orders.

*Finalize the discussions on Canadian Entitlements and PNCA by year end 1997.*

Canadian Entitlements have been agreed to and returned to Canada, and the new PNCA has been signed.

*Continue to utilize and incorporate Prosym, an hourly production cost model, into the data/resource analysis used by the company*

The use and refinement of this model continues at Avista. This hourly model is being used in planning and optimization functions.

*Use Wholesale Marketing activities to maintain short-term and long-term resource balance.*

Avista uses the markets to buy and sell both short-term and long-term to assure that the resource supply is sufficient for both the retail and wholesale customers, and to optimize the use of resources to meet system requirements.

*Identify through surveys customers acceptance of a green power tariff and if feasible implement by June 1998.*

Although the focus groups indicate a small number would be interested in a green tariff, the majority of the customers view us as *being green* through its hydro generation. If customer choice is implemented, Avista will probably offer a full menu of choices to its customers, including green power.

## RESOURCE UPDATE

### Resources

- Avista's hydroelectric plant availability rate, an enviable 97 percent, enabled the company to achieve a 1997 cost of production that ranked among the very lowest in the nation. Both access to Canadian and domestic natural gas sources gives abundant, reliable supplies that can be delivered at equally competitive market rates.
- In early 1999, the company submitted its application for relicensing two hydroelectric projects on the Clark Fork River, the final step in the largest collaborative relicensing effort in U.S. history. Avista worked with Native American tribes, conservation associations, property owners, non-governmental organizations, and local, state, and federal agencies- 39 stakeholder groups in all, to create a "Living License". All parties agree to work together over the 40 or 50 year life of the license to address issues as they arise. This revolutionary concept quickly emerged as an industry model, and the company received the National Hydropower Association's 1999 Hydro Achievement Award for Stewarding Water Resources as a result of this collaborative approach. On February 23, 2000 the Federal Energy Regulatory Commission issued to Avista a new 45-year operating license. This relicensing represents the first time that a large hydroelectric project has successfully received a new license on time.
- In 1999, the company completed the program to replace all four runners at Long Lake hydro facility, which increased the capability from 72.8 MW to 88MW.
- On February 12, 1999 at 6:00 p.m., after receiving all regulatory approvals, Avista turned the Meyers Falls Hydroelectric Plant over to Hydro Technology Systems, Inc. The sale of Meyers Falls was in the best interest of Avista's customers and shareholders. The purchaser has elected to sell power from the plant to the company for a period of up to eight years at a price of 21.85 mills per kilowatt-hour. The selling price of the hydro facility was \$316,000.
- The 1,340 MW coal-fired Centralia generating facility in southwest Washington was sold on May 10, 1999 to TransAlta for \$554 million. The selling price was for both the thermal generating station and the adjacent coal mine. The generating plant was sold for \$400 million, of which Avista would receive its ownership share of 15 percent. The sale was subject to a number of state and federal regulatory reviews. On May 5, 2000 the sale was completed.
- The Colstrip fuel agreements were mediated in 1998, effectively reducing the costs of coal commodity beginning 7/1/00 and the coal transportation costs beginning on 7/1/01 and eliminated further contract reopeners that were to begin on successive five-year anniversary dates, respectively. The parties also agreed that the Buyers (other than Puget Sound Energy, Inc.) had met their Final Reclamation obligations and were indemnified against any future costs of final reclamation. The mediation also established a governance body to provide the Buyers with approval rights for





# APPENDIX B

# LOAD FORECAST

# ELECTRIC SALES FORECAST

## **INTRODUCTION**

The 2000 electric sales forecast was prepared during the summer of 1999. It is the first step in the IRP process, namely the assessment of electric power demand so that studies for optimal supplies can be performed.

The forecast of firm sales to the core-market is the most critical forecast element. Customers in the core-market segment include residential (both single and multi-family households), small, medium, and large-sized commercial customers (stores, offices, hospitals, schools, and warehouses), and small, medium, and large-sized industrial customers (involved in product manufacturing). A small irrigation load is distributed between commercial and industrial market segments, while street lighting loads are counted in commercial, industrial, and as a separate segment. The requirements of the core-market segments place demands on the delivery system (both distribution and transmission) for which generation capacity is acquired, either by ownership or purchase contract.

Requirements for other load obligations, either through direct delivery or by contract, to both end-use customers and other utility companies, is discussed elsewhere in this document.

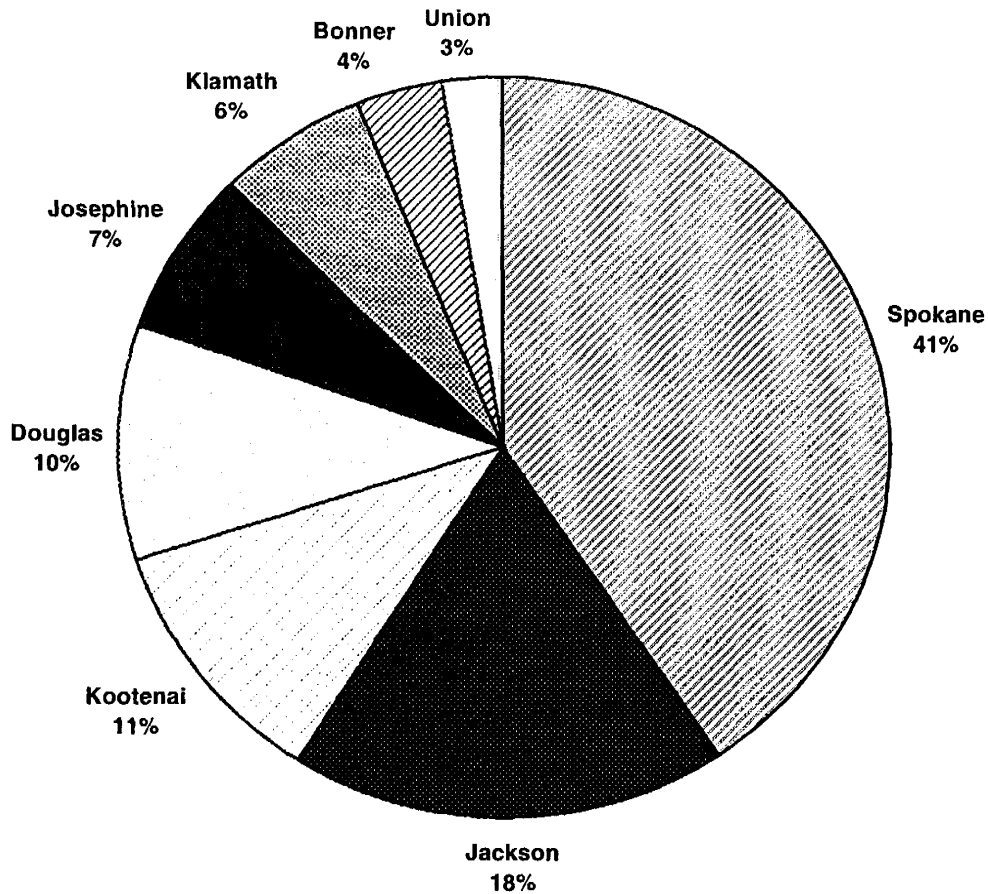
### **Service Area Economic Forecasts**

In a change from past practice, Avista purchases County-level forecasts for eight principal customer concentrations company wide. For Oregon, the five counties represent only a natural gas service area as presently constituted. For Washington and Idaho, where Avista Utilities provides both electricity and natural gas energy services, the three counties of data contain in excess of ninety percent of economic activity in the entire electric service area. Each county model produces separate detailed forecasts for employment, income, and population. The income and population forecasts should be considered as results of the economic forecasts, since the cause and effect relationship modeled treats employment as the principal independent variable. Avista Utilities treats its service area as a whole, differentiated by retail product, namely electricity and natural gas. Avista Utilities is providing electric services in a portion of its territory, but the entire territory is exhibiting the same levels of economic growth.

### **Population**

The eight counties show increases from 1,000,550 in 2000 to 1,093,550 in 2010, representing a cumulative increase of 9.3%, or a compound rate of 0.9%, which is about 1.5 times the national rate of growth expected for the same period. Washington and Idaho growth is proportionate, shown in the accompanying charts with cross-hatch. The Population shares by county in 2010 are shown below:

**Fig.B-1**



### **Employment**

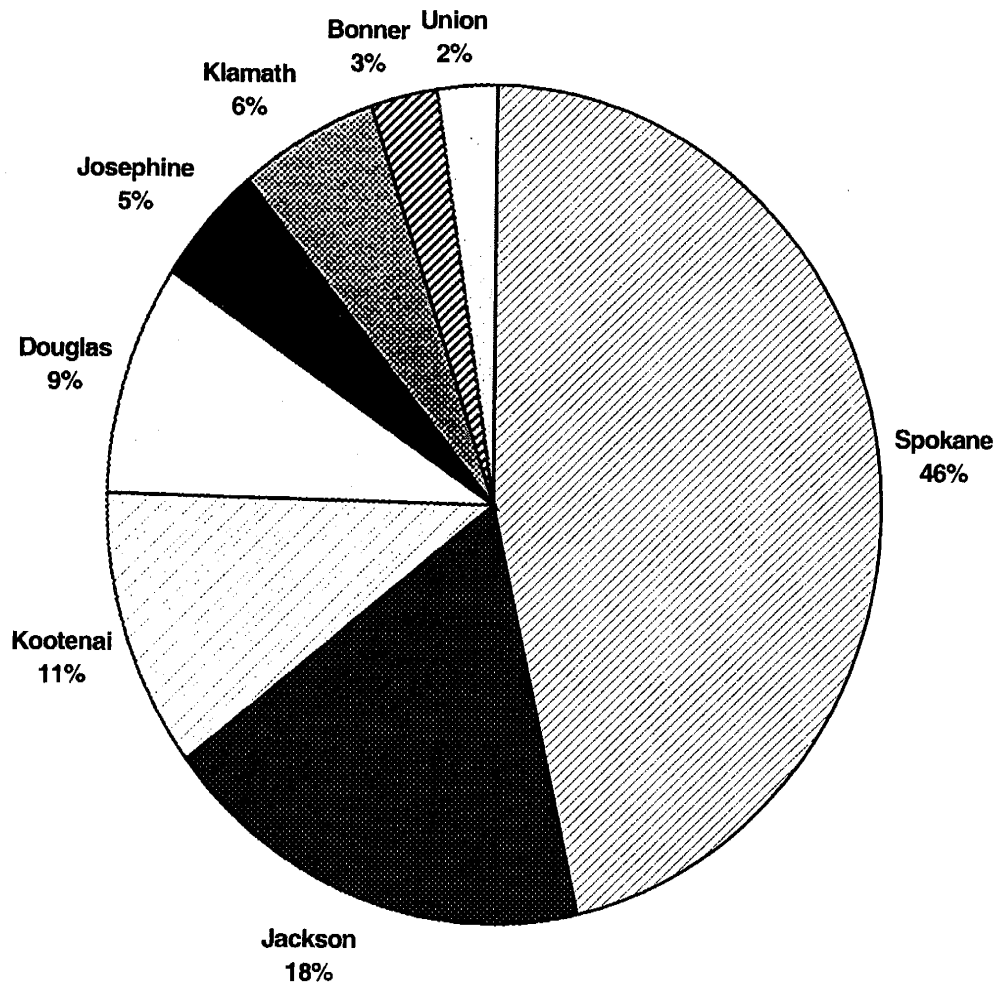
Non-agricultural employment is the sum of the components of manufacturing and non-manufacturing employment. Agricultural employment is small. Each of the available components of employment are forecasted separately. Components include: construction; finance, insurance, and real estate; federal government; state and local government; durable manufacturing; non-durable manufacturing; transportation and utilities; services; and trade. The eight county employment grows from 414,400 in 2000 to 465,800 in 2010, and Washington and Idaho are again exhibiting proportionate growth. This job growth is 12.4% cumulatively over the ten years, and averages 1.2% compounded. This rate is slightly faster than the 1.1% U.S. growth expected over the same period.

Two factors explain the slow employment growth relative to the population growth: First, the economies of each county are significantly dependent on resource-based industries, like mining, forest products, and farming, which are slow-growth performers nationwide;



and, second, each of these counties has an above average number of retirees, which is expected to trend upward. These retirees represent a non-employed sector of the economy that adds to population and provides a multiplier into the local areas through spending of respective retirement income from public and private sources. Therefore, the services and trade employment growth is offsetting the declines in the extractive sectors of the economy. In fact, services employment is growing at double the rate of overall employment, slightly faster than the U.S. growth.

The employment shares by county are shown below: **Fig.B-2**



## **Personal Income & Inflation**

Nominal personal income (before taking inflation out) is expected to grow in the service area by 4.6 percent per year, compounded. The increase from \$22.92 billion in 2000 to \$35.77 billion in 2010 defines the footprint for utility service areas of Avista Utilities. Over the same period, the chain-weighted personal consumption deflator averages 2.2 percent.

## **Price**

Electric price forecasts are based on a no-deregulation scenario. The price forecast scenario assumes retail rates increase 1.5 percent per year. This increase averages only two-thirds the overall rate of inflation. This price forecast indicates that price elasticity will not play an important role in electrical consumption trends.

The forecasts of natural gas prices are incorporated in the use per customer econometric equations. Retail prices of natural gas are expected to average 2.6% increases over the forecast period, before taking inflation out. After taking out inflation, prices are expected to be only four percent higher in inflation adjusted terms in 2010 than in 2000. The elasticity impact of this anticipated price change is negligible. Price increases at the retail level of five to seven percent every two to three years are built into the base case forecast.

The commodity cost of gas represents approximately half of the delivered cost of gas to firm residential, commercial, and industrial customers. DRI's forecast at the national level for 2000-2010 has commodity prices escalating at 5.7 percent average over the period. Over the same period, utility natural gas costs are expected to increase only 5.3 percent. Forecasts of natural gas costs are notoriously volatile, and depend for the most part on the assumptions related to oil prices. As described above, oil prices are expected to increase 5.0 percent on average. DRI continues to correctly treat natural gas as a superior quality fuel, as compared to oil, which is the principal explanation for the positive difference.

## **FORECAST METHODOLOGY**

Avista Utilities utilizes econometric models to produce sales and customer forecasts. Econometric models are systems of algebraic equations which relate past economic growth and development in the geographic communities served electricity with past customer growth and consumption. The previous discussion of economic forecasts provides the basis for the input variables of the cause and effect relationship modeled over the past.

Typically, a minimum of ten years of historical relationships are modeled to provide a certain level of confidence that we have the relationship correctly identified. The data utilized is separated by state, by rate schedule, and by customer class. The dominant impact in the equations for firm sales is the variable which measures cold weather. We use heating degree days for the appropriate geographical area in the model. The 30 year National Weather Service average is used to project the future. Hot weather is

becoming more important. Incorporating cooling-degree days into the econometric relationship is underway, the results of which will be reported in the next IRP.

## FORECAST RESULTS

The results of the forecasting process produce forecasts of the number of customers in each customer group being served each month, and the average electricity use by each group. For example, the residential class in Washington has four main groups, commonly referred to as schedules. The small residential user is on schedule 1. The number of customers in schedule 1 is forecast for ten years, and the use per customer is forecast for ten years, and the sales forecast for each month of the next ten years is the product of these two series. We have summarized the ten year forecasts into annual figures, and have collapsed the groups into recognized classes of customers: residential, commercial, industrial, and street lights. Results will be presented for each class, and for each state. A PURPA cogeneration contract expires during the forecast period. We expect this customer to continue using its own generation to supply a portion of it's own load. It is important to recognize that the supply modeling procedures described elsewhere in this document use the monthly information.

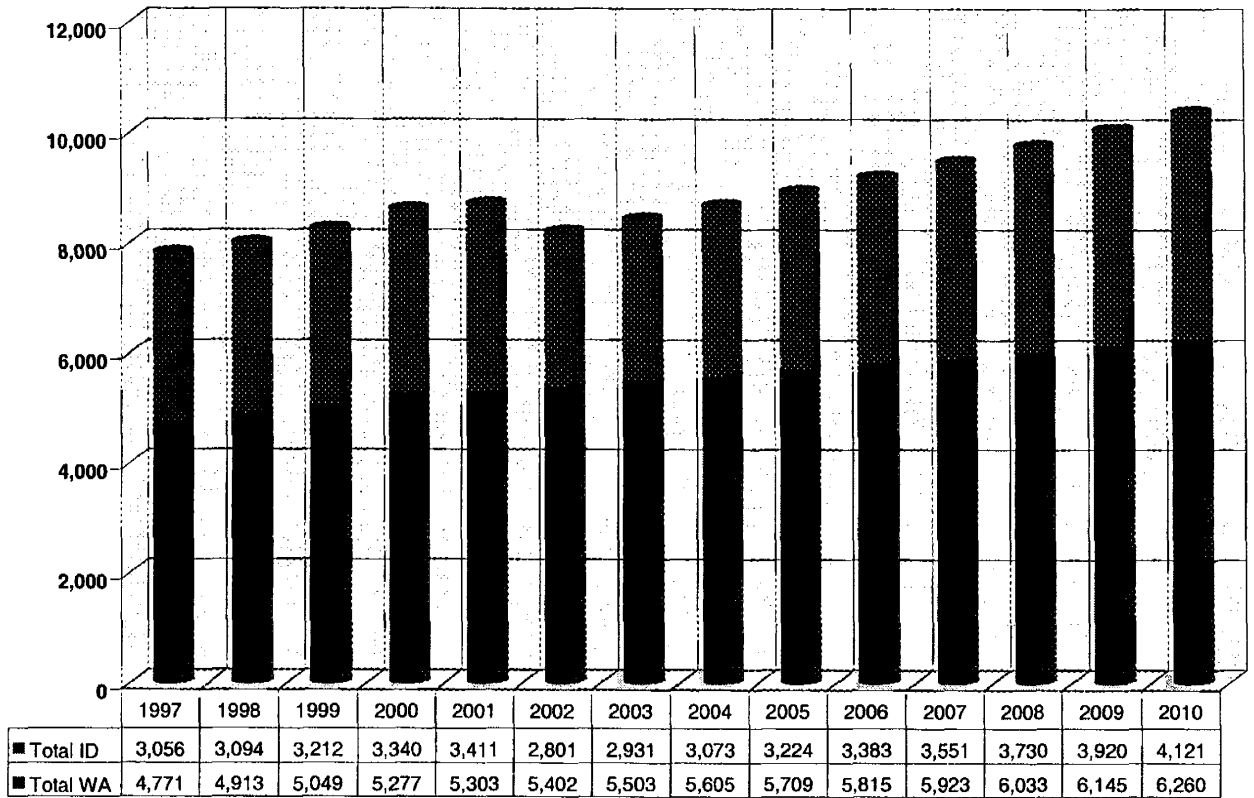
Peak load and energy forecasts are derived from the sales forecasts, as reported on the following page.

	<u>2000</u>	<u>2010</u>	<u>Compound Growth</u>
<b>Residential Customers</b>			
Washington	186,407	224,264	
Idaho	89,130	121,980	
Total	275,537	346,244	2.3%
<b>Residential kWh (million)</b>			
Washington	2,322	2,787	
Idaho	1,072	1,463	
Total	3,399	4,250	2.3%
<b>Commercial Customers</b>			
Washington	21,071	26,184	
Idaho	14,648	18,512	
Total	35,719	44,696	2.3%
<b>Commercial kWh (million)</b>			
Washington	2,113	2,578	
Idaho	946	1,891	
Total	3,059	4,469	3.9%
<b>Industrial Customers</b>			
Washington	672	743	
Idaho	507	637	
Total	1,179	1,380	1.6%
<b>Industrial kWh (million)</b>			
Washington	819	876	
Idaho*	1,315	761	
Total	2,134	1,637	-2.6%
<b>Street Lighting kWh (million)</b>			
Washington	18	19	
Idaho	7	7	
Total	25	26	0.2%
<b>Total kWh (million)</b>			
Total	8,617	10,382	1.9%

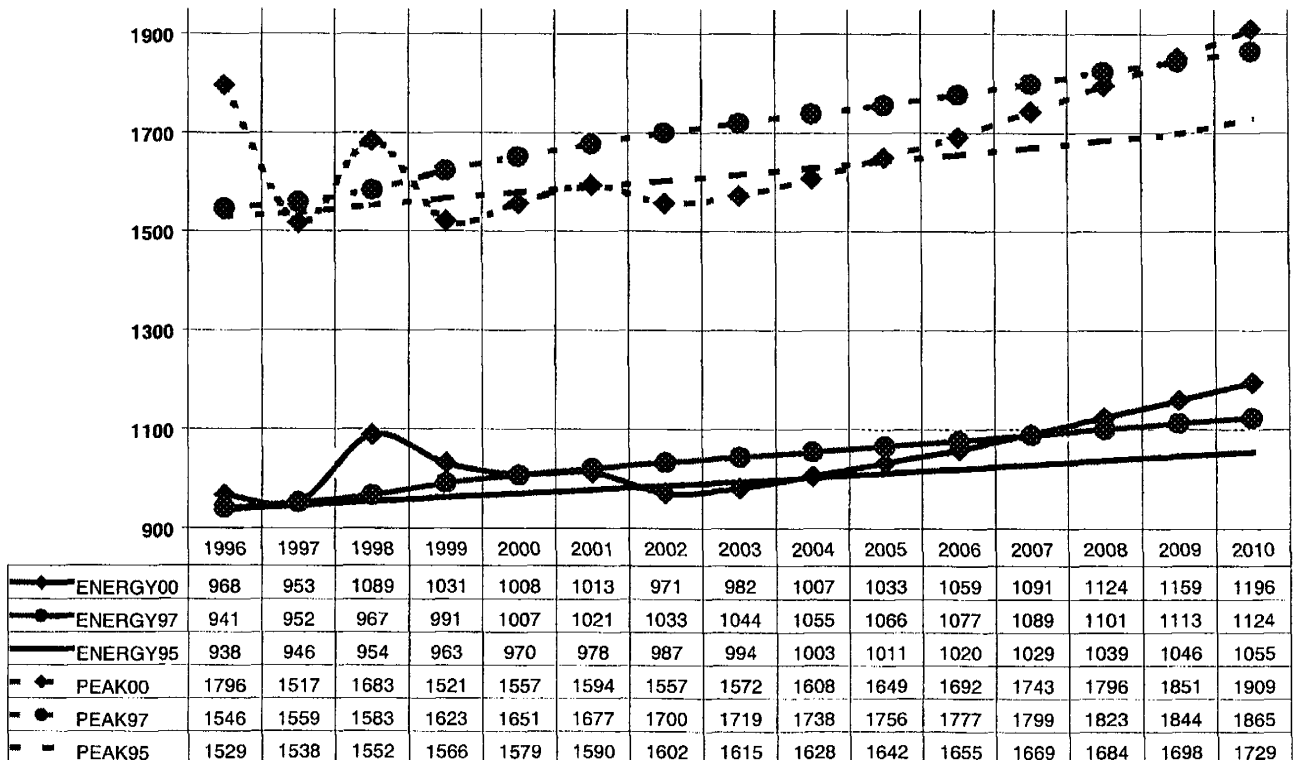
\*Reflects the expiration of a cogeneration contract with one customer.

Annual Actual from 1997 to mid-1999, forecast mid-1999 thereafter:

### Total Electric Sales (million kWh)



### Avista Corp. Energy and Peak Forecast





## APPENDIX C

# RESOURCE PLANNING

## RESOURCE PLANNING

At the present time there is a period of uncertainty for the electric utility industry. Wholesale competition is now market based. High power prices and volatility have resulted from a combination of tightening supply-demand balance, low hydro, and a dysfunctional California market. The region and the industry are experiencing a culture shift from cooperation and coordination to competition and confidentiality.

Long-term utility resource planning will be impacted by market conditions and further restructuring. The concerns of confidentiality, market positioning and sensitive information needs to be addressed as it relates to the IRPs. The company believes that the role of IRPs is still important but the process and requirements will have to change to accommodate the changes in the new utility environment. The importance of IRPs is that they facilitate better communications between the company and public (outside entities, Commission, etc.).

Avista is  
deficit  
and  
needs to  
get into  
a load-  
resource  
balance

Avista's energy needs and the energy market place have both changed considerably since the last IRP report. The company is deficit and needs to get into a load-resource balance. Avista is planning to meet its customers' needs in the least-cost manner. This IRP report describes the mix of energy efficiency and generating resources that can meet future needs at the lowest cost to the company and its customers.

Projections indicate that the majority of significant new generation additions in the United States will be natural gas fired plants. Gas demand for electricity generation is rising as gas is currently the fuel of choice. Gas is expected to maintain this role as a result of technology improvements, the low cost of gas turbines, and the growing influence of environmental concerns, as gas burns much cleaner than coal or oil.

Avista issued a Request-For-Proposals (RFP) to identify low cost and environmentally sound resource options that would best satisfy the company's resource needs. The bidding process supports the company's ongoing assessment of the cost and availability of new resources and provides input to this IRP. The resources bid to the company in response to the RFP must be competitive with other resource options available to Avista, including resources available at cost from affiliates, in order to be considered for purchase. The resources bid under this RFP are proposals for energy efficiency and power supply resources. The company received 32 bid proposals from 23 parties, for a total of over 4,400 megawatts. There were 8 energy efficiency bids, 6 renewable bids, and 18 supply or unit contingent bids. Avista is using PROSYM and its revenue requirements model to evaluate the benefit and value of these resource bids and other company projects to the company and its customers. Avista has selected the 280 MW gas-fired Coyote Springs II project and three DSM resources for 13 aMW to meet a large portion of its resource needs.

## **PROSYM**

### Chronological Production Modeling System

Prosym is a chronological modeling tool used for the purpose of producing near and long-term forecasts of electric system operation. Prosym is the Fortran-based simulation engine that applies intricate algorithms to process electrical industry data into useful results.

Prosym is a complete electric utility/regional pool analysis and accounting system. It is designed for performing planning and operational studies, and as a result of its chronological structure, accommodates detailed hour by hour investigation of the operations of electric utilities and pools. Because of its ability to handle detailed information in a chronological fashion, planning studies performed with Prosym closely reflect actual operations. Prosym was the first second-generation chronological model, with new technology that vastly speedup the simulation process that used open standards for both input and reporting to link up with the latest software tools. Now, it is the first third-generation model, capable of analysis not only in the traditional cost-based world, but also in the rapidly evolving pools and free markets for power worldwide.

Prosym uses a powerful data input method capable of handling the large volume of information required to perform highly detailed studies of electric generation and pool operation.

Electric utilities, and generation pools, operate generation resources, energy storage devices, and load control systems to match generation and load on an instantaneous basis. This real-time operation entails using highly sophisticated control systems, which match generation levels with load virtually instantaneously. It is not analytically necessary to represent this level of time detail in performing planning studies, which have a time horizon of weeks to years. What is necessary, is a level of time detail that allows the planning study to obtain a reasonable approximation of actual system operation. Hourly time steps can accommodate the modeling of virtually any utility or pool situation, so the basic time unit used in Prosym is one hour. In each hour of a study period, Prosym considers a complex set of operating constraints to simulate the least-cost operation of the utility. This hour-by hour simulation, respecting chronological, operational, and other constraints in the case of cost-based dispatch, and relevant pool or independent system operator rules in the case of bid-based dispatch, is the essence of the model.

Prosym simulations consist of a two step process: (1) projection of the load data over the study period and (2) simulation of utility or regional operation. As the company contemplates the addition of one or more resources to its portfolio it will be faced with a different resource stack and fuel mix. The new resources will have an impact on the resource dispatch sequence because of the potential fuel supply and marginal costs. Avista uses Prosym to model its resources, to meet its load requirements on an hourly basis, and to assess the dispatch requirements and compatibility of new resources used in conjunction with existing resources, both hydro and thermal.





## RESERVES

A reasonable level of planning reserves helps the company ensure adequate generating capacity during periods of extreme weather or unexpected plant outages. Avista's planning reserves are not based on the size or types of its resources. Avista's capacity reserves include components for cold weather, generator-forced outages and contingencies such as river freeze-up at hydroelectric plants. Although they vary by year, capacity reserves for planning purposes are approximately 12 percent of the company's total resources or 15 percent of the forecasted peak system load.

The capacity planning reserves that the company has used for the past few years are shown below (figures in megawatts):

**Table C-1**

<u>Year</u>	<u>1995</u>	<u>1996</u>	<u>1997</u>	<u>1998</u>	<u>1999</u>	<u>2000</u>	<u>2001</u>
1991 Least Cost Plan	263	265	266	268	-	-	-
1993 Integrated Resource Plan	247	248	250	251	-	-	-
1995 Integrated Resource Plan	245	246	247	248	250	251	252
1997 Integrated Resource Plan	-	-	243	246	250	253	255
2001 Integrated Resource Plan	-	-	-	-	-	246	249

These planning reserves are based on 10 percent increase in peak loads which is equivalent to one day in twenty years with an additional 90 MW to account for river freeze ups and a portion of the forced outage reserves. This provides Avista with about 15 percent reserves based on forecasted peak loads. The forecasted peak loads are based on the average expected cold day. For example, the peak for January 2000 was estimated at 1557 MW (at 8 degrees F) but Avista would expect the peak to be 1713 MW on the extreme day (-10 degrees F).

The company and the Pacific Northwest region does plan for energy contingencies through planning criteria. Energy contingency for planning purposes comes from a portion of thermal plant's plant factor that is below 100 percent, which would result in an increase of purchased fuel. Another portion of the energy contingency is covered by the draw down of reservoir water that is allowed to flow through unused hydro generating units. Energy reserves have not been a factor in the Northwest region because regional planning is done under critical water conditions.

Operating reserves are considered a portion of the planning reserves and are based on 5 percent of hydro generation and 7 percent of thermal. They are those reserves that a utility is required to carry under the Coordination Agreement for that particular operating year. If an unpredictable event was to occur, such as a forced outage on a generating unit, the utility would use its operating reserves to cover the event. If the reserves being carried by the utility were not sufficient then the utility could ask for and receive reserves from other parties to the Coordination Agreement.

## ELECTRIC AND NATURAL GAS PRICE FORECASTS

Electric and Natural gas price volatility has increased

There is much uncertainty in the natural gas and electric price forecasts. Price volatility has increased recently given extremely high prices in the daily and forward markets. The company knows that there will be periods of high prices and periods of low prices as the price curves fluctuate based on demand and supply criteria. It is the company's goal to provide and use a forecast that is reasonable in its start point and reflects a longer-term expectation for price increases. Avista knows there will be variations both high and low in the future as the company forecasts these energy prices. The forecasts reflect the best information that is available at the time the forecast is made .

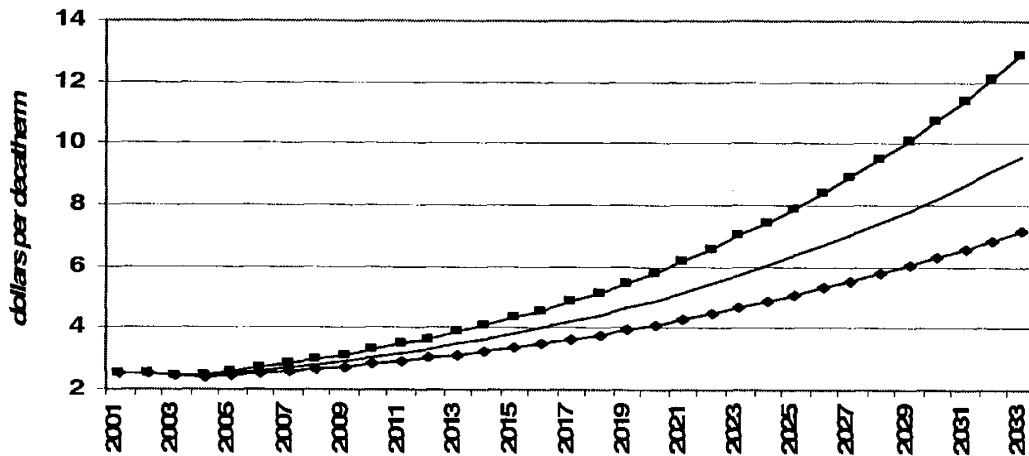
### *Natural Gas and Electricity Price Forecasts*

Key to any comparative resource decision is an understanding of the future prices for electricity. Because natural gas generation is a significant contributor to the cost of operating such a facility, the future prices for this underlying commodity cannot be overlooked. There is no sure means to accurately predict prices for even the next few days, let alone many years into the future. Avista therefore relies on a set of forward predictions it believes account for the range of possible future outcomes.

### **The Natural Gas Price Forecast**

The price forecasts developed for this update build on the wholesale natural gas forecast contained in Avista's July, 2000 natural gas integrated resource plan (Gas IRP). Contained in the Gas IRP is a base forecast of northwest natural gas prices, as detailed in the base case forecast shown below.

Figure C-1  
Northwest Natural Gas Price Forecasts  
2001-2033 nominal dollars



As detailed in the graph, wholesale natural gas prices rise from an average annual value of \$2.52 in 2001 to \$6.35 per decatherm in 2025, the end of the Gas IRP forecast. On average, this equates to a 4.1 percent annual change.

The Gas IRP does not analyze natural gas price sensitivity at the wholesale level and ends its forecast in 2025. Therefore to represent low and high forecasts, the base case escalation rate was adjusted downward and upward by 1 percent annually, respectively. Additionally, to provide a 30-year forecast beginning in 2004, the rate of change in 2025 was continued through 2033. In the low case, the cost per decatherm rises only to \$7.12. In the high case, the price increases to \$12.88. This compares to a base forecast in 2033 of \$9.60 per decatherm.

For the RFP evaluation, Avista utilized base case, high natural gas price, low natural gas price, and high load growth scenarios provided by a third party. These price studies are considered proprietary and therefore are not included with this report.

### **The Electricity Price Forecast**

With the scenarios for future natural gas prices established, electricity price forecasts was estimated using a “sparks spread.” Spark spreads identify the heat rate expressed in Btu/kWh that, when applied to a natural gas price, equate an equivalent price of electricity. For example, on 6/8/2000 the forward price for July 2000 natural gas was \$4.13 per decatherm. The July 2000 Mid-C forward price was approximately \$110 per MWh. The spark spread for July equated to 26,635 Btu/kWh.

The average spark spread through calendar year 2000, again using quotes obtained on 6/8/2000, is 21,920 Btu/kWh. Looking forward, the calendar year 2001 spark spread is approximately 17,300 Btu/kWh. To convert the natural gas price forecasts into electricity forecasts, varying spark spread values were considered. The short-term spark spreads inherent in today’s forward markets appear high given historical levels. Between 1997 and 1999, the spark spread varied from a low of 7,800 to nearly 17,000 Btu/kWh.

To represent the varying spark spread levels, Avista considered three spark spreads of ten, thirteen, and fifteen thousand Btu/kWh applied to the three natural gas price forecasts. At the ten thousand level with base gas, electricity prices rise from approximately \$24 per MWh in 2004 to \$38 per MWh in 2013, to \$96 per MWh in 2033. The average annual nominal price increase equals 4.8 percent. In real terms, the equivalent values are \$22, \$27, and \$31, equal to a 1.1 percent annual increase.

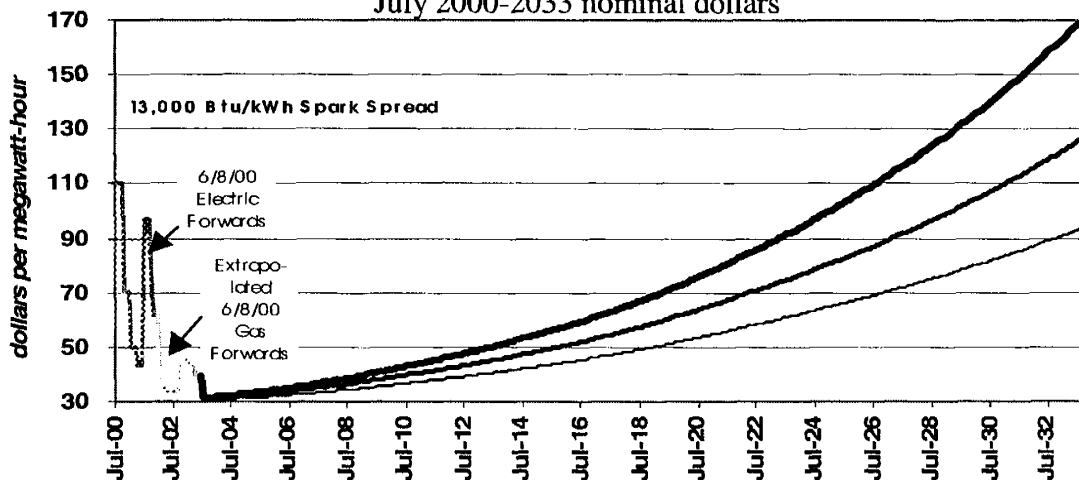
Where the spark spread is assumed to be fifteen thousand Btu/kWh, our high case estimate, electricity prices equal \$39 per MWh in 2004. Prices rise to \$61 in 2013 and then to \$153 in 2033. The average annual price escalation again is 4.8 percent nominal. In real terms, prices rise from \$36 in 2004 to \$49 in 2033, for an annual average real escalation of approximately 1.1 percent.

Avista's base case spark spread forecast is thirteen thousand Btu/kWh. At this level, electricity prices rise from approximately \$32 per MWh in 2004 to \$50 per MWh in 2013, to \$125 per MWh in 2033 using the base case gas forecast. In real terms, the equivalent values are \$29, \$35, and \$40 per MWh in 2004, 2013, and 2033, respectively. The average nominal increase equals 4.8 percent. In real terms, the forecast rises 1.1 percent annually.

Using the low natural gas price forecast and the base case spark spread, electricity prices rise more slowly at 3.8 percent annually, or 0.1 percent real. In 2004 the annual average electricity price equals \$31 per MWh. By 2033 the price equals \$93 per MWh. With the high natural gas forecast, electricity prices rise at an average annual rate of 5.8 percent nominal and 2.0 percent real. Forecasted prices increase from \$32 per MWh in 2004 to \$167 per MWh in 2033.

The following table describes the three electricity price forecasts, including forward market prices prior to August 2003.

Figure C-2  
Northwest Electricity Price Forecasts  
July 2000-2033 nominal dollars



Again, for the RFP evaluation, Avista used third-party proprietary forecasts for base case and various scenarios, for use in comparative dispatch and economic evaluations of resource alternatives. Because these forecasts are proprietary, they are not made part of this report.



# APPENDIX D

# RESOURCE ALTERNATIVES

## RESOURCE ALTERNATIVES

There are multitudes of resource options available to the company. Some are more suitable than others depending on capital cost, dispatchability, accessibility, operating experience, environmental considerations, and other impacts. All resource options will be evaluated including energy efficiency measures. Probably the preferred resource scenario will be a combination of resource options.

A  
combination  
of resource  
options is the  
preferred  
resource  
scenario

Some of the options that have been discussed and are under consideration are:

- Build a generating resource
- Purchase existing or new generation assets
- Complete system upgrades at generating facilities
- Negotiate a long-term power purchase agreement
- Buy in the short-term wholesale market
- Purchase the output of a generating or cogeneration facility
- Develop additional energy efficiency and DSM programs
- Buy energy efficiency through third party developers

Customer load dropping is also being considered although it is not generally considered a resource. Retail load that can be interrupted or curtailed under specific circumstances can free-up temporary capacity and energy. And as such, the company plans to explore those possibilities through contract negotiations with large customers, or through a third party.

The initial screening of resource costs uses data from the Power Council, actual sites being constructed or just recently constructed, and information received from national publications. Much of this information is shown in Table D-1. The mill per kilowatt hour figures are nominal levelized costs, in 1999 dollars.

Nuclear plant costs are not on the list, although it is known (from previous Power Council studies) that nuclear total cost is about 100 mills/kWh or ranked on the high end of the Power Council's geothermal projects.

Biomass plants are also not on the list except for land fill gas and biogasification plant. The analysis show that biomass plants have total costs in the range of the low geothermal costs or about 70 to 80 mills/kWh.

Many of these resources have costs that are very site specific, especially the renewables like, wind and geothermal. Avista would need to do a very detailed cost analysis based on a particular site location in order to assess ultimate viability of these options.

Avista is constantly assessing the markets in order to buy and sell power on an hourly and daily basis. Most utilities and marketers don't want to commit to long-term sales due to the uncertainty in the markets. At this time other utilities in the Northwest find themselves in the same situation as Avista so a long-term commitment from them for a

power supply would not be very likely. Avista has included in the 2000 RFP a provision to bid to the company a long-term power supply contract.

Avista's energy efficiency programs are evaluated in detail on a trimesterly basis and submitted to the company's External Energy Efficiency (Triple-E) Board for review. These reports cover the full menu of standard practice tests and descriptive statistics and are disaggregated by customer segment and technology. These reports are the basis for company program management efforts as well as providing a foundation for meaningful oversight by the Triple-E Board. The company has also assessed the potential for enhancements to specific programs to meet utility resource needs and will be assessing the potential for capacity and peak-energy targeted programs in the near future. Please see Appendix J for further information.

Avista has historically planned and developed various resource types. The company has experience with hydro, coal, natural gas, and biomass generating plants and demand-side resources. This operating experience gives the company valuable information that can be used in its resource evaluations.

Avista needs a resource that can provide additional benefits in support of the existing generation system. What is needed is a resource that can be dispatched, follow load, and provide a capacity component. In other words, as an entity with a control area, the company needs resources that are dispatchable and meets energy and capacity requirements under a variety of conditions.

A natural gas fired electric generation plant is one example of a resource that could meet those needs stated above. Natural gas plants can be built relatively quickly with relatively low capital costs and discharge less pollutants into the air than other fossil fuel plants.

At this point in time the following resources would not pass the initial screening. The following costs are nominal life-cycle, levelized costs.

- Nuclear: Costs are over the 100 mills per kilowatt-hour range. The total cost and the lack of public acceptance make this resource option unacceptable.
- Coal: Costs are 80 to 90 mills. The total cost and cost uncertainty in air quality issues make this resource option unacceptable.
- Wind: Costs are 60 to 80 mills. There are indications that costs are declining but our studies show there are not favorable sites in our service territory so transmission costs would have to be added. Because wind is intermittent the resource would have to be discounted for lack of capacity component. This would make this resource option unacceptable.
- Geothermal: Costs are 80 to 100 mills making this resource option unacceptable.
- Solar: Costs are over 240 mills making this resource option unacceptable.

These costs are presented for general comparison purposes. The company solicited resource bids from the market in a Request-for-Proposals (RFP). The company hoped for





**Table D-1**  
**Alternative Resource Options**  
Source: NWPPC (6/00)

Project Type	Fuel Type	Nominal Life-Cycle Levelized Cost (1999\$)			
		Total	Capital	O&M	Fuel
250 MW CC - West & A2-14 Block 2 Base	Gas	41.18	13.23	3.75	24.21
2x160 SCCT Low	Gas	41.84	5.69	1.78	34.36
250 MW CC - Eastside Block 2 Base	Gas	42.23	14.11	3.98	24.14
2x160 SCCT Base	Gas	42.47	6.32	1.78	34.36
2x160 SCCT High	Gas	43.09	6.95	1.78	34.36
High Plains Wind (AB, MT, WY, CO, NM)	Wind	60.77	47.77	13.00	0.00
High Plains Wind (@ Main Grid)	Wind	69.48	53.21	16.27	0.00
Landfill Gas Recovery	Landfill Gas	69.69	28.84	8.23	32.62
Pacific Coast Wind (BC, OR, WA, CA)	Wind	78.75	61.55	17.20	0.00
Advanced Coal (fluidized bed)	Coal	79.68	37.88	7.89	33.91
Geothermal 4th Plan Group 1- Opt.	Geothermal	79.71	59.77	19.94	0.00
Geothermal 4th Plan Group 1- Base	Geothermal	79.91	59.92	19.99	0.00
Cascades Geothermal – Optimistic	Geothermal	81.26	61.09	20.17	0.00
Geothermal 4th Plan Group 1- Pessimistic	Geothermal	81.35	60.52	20.83	0.00
Cascades Geothermal – Base	Geothermal	81.63	61.41	20.22	0.00
Cascades Geothermal – Pessimistic	Geothermal	82.34	61.72	20.62	0.00
Conventional Coal (300 MW)	Coal	88.57	41.25	9.78	37.54
80MW SCCT, 4/29 Pessimistic	Gas	92.08	38.75	9.95	43.38
Basin & Range Geothermal – Optimistic	Geothermal	103.39	78.06	25.33	0.00
Basin & Range Geothermal – Base	Geothermal	103.57	78.24	25.33	0.00
Basin & Range Geothermal – Pessimistic	Geothermal	105.47	79.02	26.45	0.00
25 MW Bio-Gasification CC (4 <sup>th</sup> Plan)	Biomass	122.45	52.23	33.01	37.21
Basin & Range Wind (ID, AZ, UT, NV)	Wind	135.44	104.78	30.67	0.00
80MW SCCT, 4/29 Optimistic	Gas	144.59	69.44	19.79	55.37
80MW SCCT, 4/29 Base	Gas	148.45	73.30	19.79	55.37
Aurora Fuel Cell (Distribution CG)	Gas	172.68	125.13	25.37	22.17
Eli PV @ Grid (50 miles)	Solar	242.99	237.65	5.33	0.00
Whitehorse PV @ Grid (50 miles)	Solar	284.24	278.20	6.04	0.00
Whitehorse PV @ Grid	Solar	291.30	280.55	10.75	0.00
PV Shingles	Solar	558.37	549.86	8.51	0.00
Roof Rack PV	Solar	611.47	602.95	8.51	0.00
Aurora Fuel Cell (Peaking)	Gas	823.00	674.86	99.65	48.49

## DISTRIBUTED GENERATION TECHNOLOGIES

Distributed Generation can be used as an alternative and/or supplement to utility resource additions.

### Technology Overview

The definition of Distributed Generation is- generation, storage, or DSM devices, measures and/or technologies that are connected to or injected into the distribution level of the power delivery grid. The Distributed Generation (DG) can be located at customer's premises on either side of meter or at other points in the distribution system. These technologies are installed by customers, energy service providers or a utility distribution company at or near a load for an economic advantage over the distribution grid-based system.

DG can potentially have a greater value than grid power due to:

1. enhanced customer value
2. distribution system benefits
3. back-up or emergency power
4. social or environmental value

These values are the result of DG being able to augment central station plants and optimize transmission and distribution asset utilization, facilitate competition and expand consumer choice, and provide services in an unbundled electric service.

By dispersing generation resources, and siting them closer to loads, the potential exists for utilities and other energy service providers to:

1. Provide peak shaving in high load growth areas.
2. Avoid difficulties in permitting or gaining approval for transmission line rights-of-way.
3. Reduce transmission line costs and associated electrical losses.
4. Provide inside the fence cogeneration at customers' industrial or commercial sites.

There seems to be at least two distinct DG markets. One market is for generation in the kilowatt range, represented by devices such as the new microturbines or small fuel cells. The other market, also called DG, but resembling a wholesale market more than a retail one, is for multi-megawatt units that may be on-site at a large commercial or industrial facility. These units are most likely large, aeroderivative turbines, reciprocating engines or large fuel cell plants. The small units can be handled by the existing distribution system, while the larger units would require distribution enhancements and special contracts.

DG is composed of a variety of technologies, some of which are old, and most would have a different niche and would be deployed differently. These technologies include:

- |                             |              |
|-----------------------------|--------------|
| Internal combustion engines | Gas turbines |
| Fuel cells                  | Batteries    |

Micro-hydro	Wind systems
Photovoltaic	Flywheels
Micro-turbines	Stirling engines
Magnetic energy storage	Solar-dish stirling
Diesel engines	Aeroderivative turbines

Common traits in DG technologies are the following:

1. Mass produced
2. Modular
3. Small (<20 MW)
4. Support system reliability
5. Provide economic advantage to end-user
6. Provide customer and utilities an alternative to standard generation options

Following is a list of distributed generation sources and their efficiencies. All efficiencies mentioned are generating efficiency only, excluding recoverable thermal energy.

**Diesel engines** in sizes from 50 kW to 6 MW provide standby power for commercial and small industrial customers and provide transmission and distribution support. Their efficiency is 33% to 35%.

**Internal combustion engines** in sizes from 5 kW to 2 MW, provide primary power and commercial co-generation. Efficiencies: 33% to 35%.

**Combustion turbines** in sizes 1 MW to 100 MW provide industrial co-generation and transmission and distribution support. Their efficiency ranges from 33% to 45%.

**Microturbines** in sizes from 25 kW to 100 kW provide standby power, remote power and commercial co-generation. Their efficiency ranges from 26% to 30%.

**Phosphoric acid fuel cells**, in sizes from 200 kW to 1 MW, are a potential source of premium power and can provide commercial co-generation at an efficiency of 40%.

**Solid oxide fuel cells**, in 25 kW to 3 MW sizes, provide commercial co-generation and primary power with efficiencies of 45% to 65%.

**Polymer electrolyte membrane fuel cells**, from less than 1 kW to 250 kW, should be ideal for residential customers, premium power and remote power with efficiencies of up to 40%.

**Battery storage systems**, from 500 kWh to 5000 kWh, provide power quality, voltage regulation and premium power with efficiencies of 70% to 75%.

**Photovoltaic** arrays are available in sizes from less than 1 watt and up to 1000 kW. Their efficiency depends upon the relationship of sunlight to ac power, typically 10% to 20%. They are used for remote power, peak shaving and power quality.

**Wind Power.** American Wind Energy Association, Washington, D.C., estimates that wind power capacity on line in the United States will grow to 2000 MW by the year 2000.

Each DG technology shares a common need to interface with the grid. The number one barrier to distributed resources is lack of simplified, low cost interconnection capability. Some utility concerns are safety and reliability issues. Several organizations are

beginning to deal with these issues. The National Association of Regulatory Utility Commissioners has issued a Request for Proposals on generic guidelines for handling DG interconnections with the distribution grid, and the Institute of Electrical and Electronics Engineers has 23 Standards Subcommittees working on interconnection standards for DG installations.

Other technical issues include net metering, parallel operating agreements, standby charges, and the effect on gas supply. These and other issues will need to be evaluated and resolved in order to encourage the application of DG resources.

### Market Analysis

Economic impacts from DG systems may include one or more of the following:

- Load management
- Reliability
- Power quality
- Fuel flexibility
- Cogeneration
- Deferred or reduced T&D investment or charge
- Increased distribution grid reliability/stability
- Potential for increased natural gas infrastructure to support DG application

Potential benefits of renewable based DG:

- No/low noise or air pollution
- Independent of fossil fuel price changes
- Good for very small, modular applications
- Could be used on either side of a meter
- Coincident with peak summer demand when solar resource is used

Deployment issues of renewable based DG:

- Intermittent availability (unless used with storage)
- Islanding
- Less than 2 MW
- Interconnection standards and cost
- Will need grid support
- New industry, lacks public exposure

Characteristics of storage technology as a DG resource:

- Provide auxiliary services on either side of the meter
- Used by utilities, energy service provider and end-user
- Wide range of size and storage duration
- Costs will come down faster as core technologies are used for transportation
- Batteries and SMES available now

## MOST LIKELY USERS OF DG IN NEXT FIVE YEARS

	IC Engine	Small & Micro Turbines	Storage	Fuel Cell	PV	Small Wind	Large Wind
Industry	x	x	x	x			
Commercial	x	x	x	x	x	x	
Residential				x	x	x	
Utilities		x	x	x	x		x

### Advantages of Distributed Resources over Central Station Generation and T&D

- Typically can install in a few days to a few weeks for systems less than 100 kW.
- Easier to locate due to small footprint of fuel cells and microturbines. Photovoltaics may be an exception (land versus rooftop); few permits and approvals needed.
- Can be tailored to meet the needs of the customer (isolated with reserve margin, or with utility standby; parallel operating with backup).
- For isolated operation, power quality is a function of inverter harmonics or other customer load.
- Microturbines have a lower (US\$500/kW) investment cost; fuel cells and PV systems are significantly higher.
- Microturbines operating isolated without T&D costs have competitive energy prices of 8 to 10 cents/kWh (low investment and high fuel cost); fuel cells are typically 15-17 cents/kWh. Could be 7-9 cents /kWh for high volume.
- Microturbines and fuel cells can be relocated with relative ease. Photovoltaics may require moving massive structures. If a customer opts for another supplier, the generation equipment is easily relocated.
- Fuel cells have very low emissions of less than 1 parts-per-million (ppm), although safeguards for hydrogen are necessary. Photovoltaics have no emissions. Microturbines are generally less than 9 ppm for CO and less than 9 ppm for NOx.
- Microturbines and fuel cell infrastructure needs are very low if isolated operation. Can be applied in areas where line extensions and new construction are impractical or uneconomic (customers in remote areas or islands). This is a significant advantage for third world countries where only a fuel source is needed.
- On site heat recovery and hot water are available. Fuel cells and air conditioning/chiller systems can be added to reduce the cost to between 6 and 7 cents/kWh.
- Energy losses are in the range of 1% to 2%.
- The low voltage secondary feeds from distributed generation are generally not a hazard to the public.

Along with the increased demand for electricity comes the need for efficiency and economy in generation. DG applications will fill some of that need. Bechtel Power estimates that the annual world wide demand for DG will be on the order of 30 to 40 gigawatts over the next 5 years. Westinghouse estimates that 40 percent of all worldwide capacity addition from 1998 to 2008 will be DG of some form. EPRI estimates a potential market of 2.5 gigawatts per year of DG by the year 2010. U.S. Department of Energy forecasts explosive growth in DG, accounting for as much as 20 percent of all new domestic power generation capacity additions through 2010.

Major companies are investing in facilities to produce DG devices. Allied Signal Power Systems began pilot production of its 75 kW TurboGenerator units in late 1998. ONSI, a United Technologies company, has already produced more than 160 of its 200 kW PC25 phosphoric acid fuel cell power plants. Ballard Generation Systems broke ground in 1998 for its first commercial manufacturing facility, which will soon start producing Ballard's PEM fuel cells. Energy Research has constructed a plant to manufacture up to 17 MW per year of its molten carbonate fuel cells, and Siemens Westinghouse brought on-line a pilot manufacturing facility that can produce up to 4 MW per year of its solid oxide fuel cells.

Companies that are commercializing emerging distributed generation technologies are facing huge challenges. In the bulk power market, distributed energy technologies will find it difficult to compete with the nearly 60 percent efficient combined-cycle gas turbines as the design of choice for a power generator, at least in the near or medium term. Nor will they easily displace reciprocating engine gensets as the tried-and-true technology for emergency or backup generation for most end users who currently have them. DG will first have to find high-value niche applications.

BPA is projecting that DG will turn the energy grid into a two-way web that has the potential to disrupt business unless the grid itself changes to accommodate these new technologies. DG could create chaos on the transmission system through the sheer numbers of transactions and interconnections caused by small generators that go on and off line. But if its coordinated in a market-based system, that could reduce costs and increase reliability to all parts of the electric system, creating the new 'energy web'. These small, local power sources installed at substations or on the customer's side of the meter could reduce transmission congestion, support voltage, shave peaks and improve the use of distribution assets.

Most if not all the DG technologies have to overcome concerns regarding reliability, capital cost, emissions, fuel delivery and nonfuel O&M expenses. For wind generation the concern is reliability. Fuel cells strong point is environmental performance while capital cost is a concern. PV systems need to reduce their capital cost. Reciprocating engines have proven performance and installed costs lower than costs of virtually all competitors. Micro turbines, firing natural gas, can deliver single digit emissions of NOx and CO, but the problem is fuel delivery at needed pressures (250 to 500 psig).

#### Economics

The following DG economics were developed from available trade information. It is generally recognized that costs will decrease over time through new product development and consumer experience. The cost-effective threshold for customers and utilities will continue to be driven by avoided generation costs, which vary considerably though out the United States.

### COMMERCIAL STATUS OF DISTRIBUTED GENERATION

	IC Engines	Small Turbines	Micro-Turbines	Fuel Cell
Commercial Availability	Well established	Well established	New industry	Well established
Size	3 kW-5 MW	1 MW-50 MW	25 kW-200 kW	1 kW-200 kW
Installed Cost (\$/kW)	\$350-\$1500	\$500-\$900	\$300-\$1000	\$3000-\$4500
O&M Costs (cents/kWh)	0.7- 1.5	0.2- 0.8	0.2- 1.0	0.3- 1.5
Fuel Type	Diesel, Propane, NG, oil & biogas	Propane, NG, distillate oil & biogas	Propane, NG, distillate & biogas	Hydrogen, biogas & propane
Typical Duty Cycles	Baseload	Baseload, Intermed. peaking	Peaking Intermed. baseload	Baseload

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	Photovoltaic	Dish-Stirling	Small Wind	Large Wind
Commercial Availability	Well established	Year 2000?	Well established	Well established
Size	0.30 kW-2 MW	30 kW and larger	600 watts-40 kW	40 kW-1.5 MW
Installed Cost (\$/kW)	\$3,000-\$10,000	\$10,000/kW (now) \$400/kW (later)	\$2,500-\$5,000	\$700-\$1,100



# APPENDIX E

## RFP PROCESS - 2000



## AVISTA'S RFP PROCESS-2000

Avista Corp.'s projections of its requirements and resources showed significant deficits in both peak and energy. The company discussed the significance of those changes with Commission staff and also with other parties including a presentation and discussion at the June 22, 2000 TAC meeting. On July 12, 2000 Avista filed an update to its 1997 IRP for Commission acceptance. This updated IRP served as a basis for a Request-For-Proposals (RFP), which was filed for Commission approval on July 13, 2000 and then issued to potential bidders on August 14, 2000.

In addition the company placed an advertisement in the regional newspapers announcing the company's need for long-term firm power, both supply and energy efficiency resources. The advertisement was placed in the newspapers of Seattle, Portland and Spokane.

Avista's RFP is an "all-source" competitive bid RFP based on the company's identified need for 300 MW of electric capacity and energy starting in 2004. The company considered any offer of resources including, but not limited to, market energy and capacity, energy efficiency, renewable resources, turnkey plants, and construction by a bidder on a site furnished by Avista. A resource with operational flexibility capable of meeting changing needs and load conditions was identified as a preference.

The 2000 RFP goal was to identify low cost and environmentally sound resource options

The goal of the 2000 RFP was to identify low cost and environmentally sound resource options that best satisfy Avista's resource needs. This process supported the company's ongoing assessment of the cost and availability of new resources, and provided input for Avista's 2001 IRP. As stated in the RFP, resources bid to the company in response to this RFP had to be competitive with other resource options available to Avista, including resources available at cost from affiliates, in order to be considered for purchase.

The RFP was written so that proposals from energy efficiency measures competed against each other and power supply resources competed against other power supply resources. Then the most favorable resources bid to the company would be compared with Avista's own potential or existing resource acquisition programs for either energy efficiency or power supply resources respectively.

Avista developed an evaluation matrix for both supply-side and demand-side bid proposals. The power supply resource bids that passed the initial screening (completeness of bid information) would go through a production modeling process and an economic modeling analysis. The evaluation matrix then would screen those successful bids. The evaluation matrix ranked the resource bids as to their relative value provided to the company and its customers. The Commission staffs reviewed this information and their input was incorporated into the analyses. The evaluation matrix

had two main categories. The first category was Financial/Price Factors, with a weighting percentage of 65%. The second category was Electric Power and Social/Environmental Factors, with a weighting percentage of 35%. Each of these factors had subcategories that were weighted.

The demand-side proposals were to be evaluated based upon an evaluation matrix of six characteristics. These characteristics incorporated proposal price (at a 50% weighting), dispatchability (15%), customer economics and service (10%), ramping, measure life and persistence (10%), bidder credibility (10%) and portfolio value (5%). A screening team was selected to review the completeness of each proposal as it was received and to assign it to an interdisciplinary preliminary evaluation team composed of analysts, engineers and program implementation specialists knowledgeable of the energy efficiency measures and customer segments being addressed.

On September 18, 2000 Avista opened the bid proposals. The company received 32 bid proposals from 23 parties, for a total of over 4,400 MWs. There were 8 energy efficiency bids, 6 renewable bids, and 18 supply or unit contingent bids. Avista was pleased with the response received from its 2000 RFP. Some bid proposals were not complete and did not pass the initial screening. Three supply-side bid proposals did not pass the initial screen and the bid sponsors were notified on September 22, 2000.

Supply-side bids: For the supply-side bids Avista used PROSYM dispatch model, an economic model and third-party price forecast scenarios to perform analyses of the resource bid proposals received under the RFP. Those bids that scored the best were then screened through the evaluation matrix by an RFP work group consisting of employees from different departments within the company. The weighted percentages used in the company's matrix evaluation were based on each factor's contribution toward meeting company's least cost planning goals. The weighted factors were economic benefit (35%), financial capability (15%), fuel price risk (15%), fuel availability risk (5%), electric factors (20%) and environmental (10%).

On October 17, 2000 Avista completed its second screening using the modeling and evaluation matrix tools and developed its preliminary short list of the bid proposals. Comments from Commission staff asked for additional review of two bids, which were then included. Seven bid proposals made the short list from the second screen. Bidders were notified.

After gathering additional information and discussions with project sponsors, Avista evaluated the preliminary short list bid proposals against one another and against company projects. The result of this third screen was that many supply-side proposals were eliminated from the short-list for negotiation. The company met with IPUC and WUTC staff on November 28-29, 2000 to discuss results of the third screen. On December 11, 2000 the bid sponsors were so notified.

Demand-side bids: The eight energy efficiency proposals received were screened for completeness. Those proposals that contained inadequate information upon which to

base an evaluation were given the opportunity to correct their deficiencies. One proposal was eliminated at this stage for incompleteness. The remaining seven proposals were assigned to their respective preliminary evaluation teams for in-depth review.

The preliminary evaluation teams discussed with the bidders the nature of their proposal and, based upon the proposal and these clarifications, a summary of the relevant characteristics of each proposal was completed. The preliminary evaluation team also completed an initial scoring of the proposal using the evaluation matrix specified in the RFP.

A final evaluation team, composed of all of the members of the seven preliminary evaluation teams, convened to further discuss the characteristics of the proposals and to complete a consensus final scoring and ranking of the proposals. Using this ranking it was determined that five of the seven projects had the potential to be developed into proposals which were cost-effective in comparison to either the IRP avoided cost or those supply-side proposals that were in contention for short-listing.

A single negotiation team was selected to work with the short-listed bidders. Based upon these negotiation sessions the bidders were given the opportunity to modify their proposal to improve the proposals score and likelihood of final selection. Several of the bidders took this opportunity to modify their pricing structure, target markets and energy efficiency measures. Three of these five proposals were ultimately successful in being selected for contracting. These selected proposals were then advance to a due diligence and contracting team to execute the negotiated settlement for implementation.

**Coyote Springs II gas fired project was selected**

On December 12, 2000 Avista made public its resource evaluation decision. Avista Utilities announced the selection of the Coyote Springs II site near Boardman, Oregon as the preferred supply-side resource option and three demand-side management bids (13 MW in energy savings acquired over a three-year period) to meet the utility's growing resource needs.

The Coyote Springs II project is a combined-cycle natural gas-fired combustion turbine with generation output of about 280 MWs. Besides the overall cost effectiveness of the project, a key factor in selecting this resource was its fully licensed status. The construction of this plant is scheduled to begin in January 2001. Completion of the project is expected by June 1, 2002.

Under the terms of the project agreements, ownership of Coyote Springs II will be transferred at cost to Avista Utilities from Avista Corp. subsidiary Avista Power LLC, which acquired Coyote Springs II in July 2000 from Enron North America and Portland General Electric.

**Also selected were three DSM bids**

The three demand-side bids selected included measures varying from compressed air systems equipment and evaluation software to a broad variety of energy efficiency measures. One bid targeted

offices, retail facilities and food service customers while another bid focused primarily on state and local governments, higher education and public hospitals.

With these supply and demand-side resources added to Avista's resource stack, they should provide a significant portion of the needed power supply to meet the electrical requirements of the company for the next several years.



# APPENDIX F

# 2001 ACTION PLAN

## **2001 NEAR-TERM ACTION PLAN**

Avista's preferred energy strategy provides direction for the company's long-term activities. The company's new near-term action plan outlines activities that will support this strategy and improve the planning process. This appendix describes action items planned for 2001 through 2002. Progress on these activities will be monitored over the two-year planning cycle and reported in the company's next Integrated Resource Plan.

### **Public Process**

1. Continue free flowing exchange of information with TAC members.
2. Propose changes to the IRP process that will be useful in the competitive market era.

### **Demand-Side Management**

1. Pursue energy savings for the next three years with funding from the tariff rider.
2. Consider the development of programs that will allow peak shaving.
3. Determine the potential for Time-Of-Use (TOU) rates.
4. Execute and implement DSM contracts that were selected under the 2000 RFP.

### **Supply-Side Resource Options**

1. Pursue the base plan for Spokane River hydro relicensing.
2. Upgrade at least two units at Cabinet Gorge hydro facility.
3. Evaluate the effects of a micro turbine on the system.
4. Installed inlet coolers at Rathdrum combustion turbines for additional summer peaking output (completed July, 2000).
5. Evaluated RFP bids, compared to company options, and selected options that were cost effective and that best met company's long-term resource need (completed December 2000). Complete transfer agreements for selected supply-side resource.
6. Pursue re-negotiation efforts with Mid-Columbia PUDs.
7. Evaluate the need for additional supply or generation units to handle variability in hydro, retail loads, and potential generation outages under projected market conditions.

### **Resource Management Issues**

1. Implement relicensing programs on the Clark Fork River hydro projects, as part of the "Living License" commitment.
2. Continue to examine and pursue cost-effective efficiency improvements at generation facilities.

## AVISTA'S PREFERRED RESOURCE STRATEGY

Avista's Requirements and Resources show some significant deficits both in peak and annual energy for the next ten years. For the short-term, the company is also facing short falls in both capacity and energy. The company will probably receive some energy resources from the 2000 RFP to help meet these earlier needs. Short-term purchases, energy efficiency measures and hydro upgrades will meet these short-term deficits.

In the year 2004 the company shows significant deficits in both energy and capacity. The deficits of about 300 MW in both energy and capacity fluctuate through the years depending on contract terminations. By the year 2009 the energy deficit is still about 300 aMW while the peak deficit has increased to 400 MW. Future years will show increasing deficits as the company experiences increasing load growth.

Strategy is to  
acquire  
supply-side  
and demand-  
side  
resources  
and cost-  
effective unit  
upgrades

One of the decisions of the 2000 RFP process was the selection of Coyote Springs II, a gas-fired combined cycle combustion turbine. With the 280 MW Coyote Springs II addition to our resource stack in 2002, it will provide a significant portion of the needed power supply to meet the electrical requirements for the following ten years. Even with this addition, the company will experience surpluses and deficits on a monthly, weekly, daily and hourly basis depending on weather and hydro conditions. These swings in the power supply will need to be handled daily through short-term purchases and sales in the market place, and/or the acquisition of other power supply options.

Avista currently has long-term purchase rights to power output from four mid-Columbia River hydroelectric plants owned by three Public Utility Districts. Each of the mid-Columbia contract purchases represents a very low cost and a flexible resource for the company. Contracts with Grant County PUD are the first to expire, with Priest Rapids terminating in 2005. The company is involved in re-negotiating these contracts. Avista relies on mid-Columbia plants to handle a certain amount of company need for flexibility. Therefore the company expressed a preference for flexible resources in the 2000 RFP.

Resource additions will need to be flexible enough to handle the loads being ramped up and down under a variety of seasonal and load conditions. Avista experiences load changes of 100 MW or more during several hours of each day. Flexibility will allow the resources to be dispatched. Purchases from the market will not handle this need. The market tends to offer standard heavy load hour and light load hour products that do not meet load shaping or following needs.

Avista was pleased with the number and variety of bids received in the RFP process. The quality of the proposals provided a good reflection of the market. The RFP proposals will also be used to compare other company options. Avista chose the least-cost option between RFP bid proposals and various build/implementation resource opportunities. The supply-side resource chosen was a natural gas-fired electric generation plant. Natural gas plants can be built relatively quickly with relatively low capital costs and discharge less pollutants into the air than other fossil fuel plants. The company would







# APPENDIX G

## RESOURCE AND CONTRACT INFORMATION

## EXISTING AVISTA GENERATING CAPABILITY

The following is a tabulation of the maximum generating capability (the amount of energy the plant is capable of producing during peak conditions) and the nameplate capability (the amount of energy the equipment within the plant was designed to produce) for each of Avista's generating plants. Avista has no resource scheduled for retirement in the next 10 years.

Table G-1

<u>Year</u>	<u>Plant</u>	<u>Maximum Capability (kW)</u>	<u>Nameplate Capability (kW)</u>
1890	Monroe Street <sup>3</sup>	14,800	14,800
1906	Post Falls	18,000	14,750
1908	Nine Mile <sup>3</sup>	24,500	26,400
1910	Little Falls	36,000	32,000
1915	Long Lake <sup>3</sup>	88,000	70,000
1922	Upper Falls	10,200	10,000
1952	Cabinet Gorge	236,000	231,300
1959	Noxon Rapids <sup>3</sup>	528,000	466,200
1978	Northeast (gas/oil)	69,000	61,200
1983	Kettle Falls (wood waste)	49,000	50,700
1984	Colstrip <sup>1</sup> (15% ownership coal-fired)	222,000	233,400
1995	Rathdrum <sup>2</sup> (gas)	176,000	166,500

- <sup>1</sup> The Colstrip coal-fired plant has test capability of 1,400 MW (total for units No. 3 and No. 4). At 15%, Avista's share of the project is 210 MW. The plant operator (Montana Power) operated the units in an over pressure mode that results in the plant exceeding its tested capability. Recent history indicates the plant operates consistently above 1,400 MW and for load and resource tabulations is shown as 222 MW.
- <sup>2</sup> The Rathdrum gas-fired, simple-cycle combustion turbines (two units) were declared available for commercial operation on January 1, 1995. The January rating capability for these units was 176 MW.
- <sup>3</sup> Monroe Street's intake initiation was resolved and its capability was increased from 13 MW to 14.8 MW. Nine Mile's peak capability was decreased from 29 MW to 24.5 MW. In 1999, Avista completed the program to install all four units at Long Lake with new runners, which increased the capability from 72.8 MW to 88 MW. Noxon Rapids total peak capability has been decreased from 554 MW to 528 MW.

## **RESOURCE AND CONTRACT INFORMATION**

The primary objective of the IRP is to develop a long-term plan for meeting Avista's energy requirements. For this 2001 IRP Avista has looked at the situation for the next ten years but has extended the economic analysis for the life of potential resources.

The resource of choice among utility planners is the combined cycle combustion turbine (CCCT) using natural gas as the fuel. These types of generating resources provide low capital costs, use fuel that is in abundance, and have minimal environmental problems compared to other types of thermal generation. In addition, these CCCT units can be sited and constructed in four to five years.

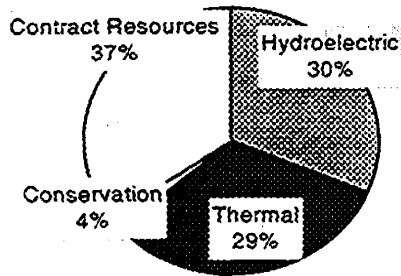
This appendix discusses the resources and contracts that are coordinated to achieve the IRP objective. Specifically, Avista's current need for resources is described. This is then followed by an outline of the power sales agreements Avista holds with utilities and power producers throughout the region.

### **RESOURCE NEED**

Based on Avista's current resource requirements, the company has a significant need for new firm electric resources. Avista determined the best options for future resource additions, which included issuing a Request for Proposals (RFP) that was all-inclusive. The RFP asked for energy efficiency measures and power supply options, including power plant site and turnkey power plant. Avista completed its RFP process and selected supply-side and demand-side resources to fill a significant portion of its resource need.

Without resource additions, the company is facing significant energy and peak deficits. By the year 2009 the peak deficit is 402 MW and the energy deficit is 301 aMW. After 2006-07, all wholesale sales have terminated except the capacity sale to Portland General Electric. Planning reserves are still included as a requirement.

**Table G-2  
Avista Utilities  
2000 Existing Resources  
for Retail  
(Under Critical Water Conditions)**



Resource	Energy Capability (in Average MWs)
<b>AVISTA RESOURCES</b>	
Hydroelectric	313aMW
Thermal	303aMW
Conservation	43aMW
<b>CONTRACT RESOURCES</b>	
Hydroelectric	87 aMW
Cogeneration	55aMW
Utility Purchases	250aMW
<b>Total Resources</b>	<b>1051 aMW</b>

Avista continues to assess resource opportunities—focusing on those that provide the most benefits to the company and its customers. This continual assessment of available resource alternatives helps Avista respond to constantly changing conditions.

The sale of the Centralia coal-fired plant resulted in the loss of 201 Mw of capacity and 177 aMw of annual energy from Avista's resource portfolio. The company entered into a short-term market contract with TransAlta, the new owners of Centralia, to replace a majority of the generation lost with the sale of the plant. The term of this contract starts in July 2000 and extends through December, 2003.

In 1999, the company completed the program to replace all four runners at Long Lake, which increased the compatibility from 72.8 MW to 88 MW. In the planning stages are turbine runner replacements and generator rewinds for three units at Cabinet Gorge and two units at Noxon Rapids. There is also a possibility of an Upper Falls turbine runner replacement and generator rewinds for three units at Little Falls.

## TABULATION OF FIRM REQUIREMENTS AND RESOURCES

Avista's 10-year tabulation of firm requirements and resources shows the company's load and resource position on an annual basis for the next ten years. The line items are the various loads, resources and contracts the company holds by year. The peak column shows the expected maximum capability and requirements of the company during the year—this peak normally occurs in January. The average column shows the expected 12-month annual average energy numbers for each year. The hydro numbers are based on a one-year critical period (1936-37 water year) from the Final Regulation done by the Northwest Power Pool, and reflects the reservoir levels in January per the hydro regulation study.

All the requirements are shown at the top of the page. Most of the purchases and sales contracts end by the year 2004. The peak and average forecasted loads are shown on line 1 labeled System load. Line 17 Reserves are Avista's planning reserves and are part of the total Requirements (as described in Appendix B).

The Resource section is comprised of the resources and purchase contracts. Line 19 shows the system hydro and line 20 is the contract hydro from the mid-Columbia PUD projects (under critical water conditions). The mid-Columbia numbers decrease due to the Priest Rapids Contract ending in 2005 and the Wanapum contract ending in 2009. Avista is hopeful that a contract extension can be negotiated with Grant County PUD in the near future. Lines 24 and 25 are the company's existing single-cycle combustion turbines, and lines 33 and 34 are the expected thermal generation output from Kettle Falls and Colstrip.

Line 23 shows a cogeneration contract terminating at the ends of 2001. This is a 10-year contract with an industrial customer to buy 55 aMW of cogeneration and continue serving their 90 MW load. Avista expects the customer to use its own generation to supply a portion of its own load and the company would serve the remainder of the load.

Line 29 shows the BPA residential exchange contract with the 47 MW flat delivery of power to the company from BPA. There is no dispatchability or flexibility with this contract. Although this contract has not been signed, the company feels it is firm enough to be included. And finally, line 44 is the Surplus (Deficit) numbers calculated by subtracting the Total Requirements from the Total Resource numbers. In the year 2004 Avista is 287 MW deficit on peak and 318 aMW deficit on energy under critical water planning criteria.

G-6

Table G-3

AVISTA CORP.

Requirements and Resources

Line No.	REQUIREMENTS	2000		2001		2002		2003		2004		2005		2006		2007		2008		2009	
		Pk	Avg	Pk	Avg	Pk	Avg	Pk	Avg	Pk	Avg	Pk	Avg	Pk	Avg	Pk	Avg	Pk	Avg	Pk	Avg
1	System Load	1557	1008	1594	1013	1557	971	1572	982	1608	1007	1649	1033	1692	1059	1743	1091	1796	1124	1851	1159
2	PacifiCorp Exchange	0	3	0	3	0	3	0	3	0	3	0	3	0	3	0	3	0	3	0	3
3	Puget #2	100	75	67	50	33	25	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	PacifiCorp 1994	0	9	0	9	0	9	0	9	0	9	0	9	0	9	0	9	0	9	0	0
5	PGE #1	150	0	150	0	150	0	150	0	150	0	150	0	150	0	150	0	150	0	150	0
6	Snohomish 10 yr	100	88	100	88	100	88	100	88	100	88	100	88	100	88	0	0	0	0	0	0
7	Cogentrix 57 mo	100	100	100	75	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	Nichols Pumping	0	7	0	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	West Kootenay	125	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Eugene Water & Electric	10	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	PGE Sale	25	25	25	25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Pend Oreille	6	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	Montana Sale	100	100	100	58	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14	Duke Sale	100	100	100	58	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Clark2 PUD	250	137	250	85	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16	City of Cheney	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Reserves	246	0	249	0	246	0	247	0	251	0	255	0	259	0	264	0	270	0	275	0
18	TOTAL REQUIREMENTS	2871	1662	2737	1470	2086	1096	2069	1082	2109	1107	2154	1133	2201	1159	2157	1103	2216	1127	2276	1162
RESOURCES																					
19	System Hydro	936	313	936	313	936	313	936	313	936	313	936	313	936	313	936	313	936	313	936	313
20	Contract Hydro	195	76	195	76	195	76	195	76	195	76	195	76	195	76	195	76	195	76	195	76
21	Can Ent Return	-10	-5	-10	-5	-10	-5	-10	-5	-15	-5	-15	-4	-11	-4	-10	-4	-10	-4	-10	-3
22	Small Power	12	11	12	11	12	11	12	11	12	11	12	11	12	11	12	11	12	11	12	11
23	Cogeneration	59	55	59	55	59	55	59	55	59	55	59	55	59	55	59	55	59	55	59	55
24	Northeast CTs	69	5	69	5	69	5	69	5	69	5	69	5	69	5	69	5	69	5	69	5
25	Rathdrum CTs	176	62	176	62	176	62	176	62	176	62	176	62	176	62	176	62	176	62	176	62
26	PacifiCorp Exchange	50	3	50	3	50	3	50	3	50	3	50	3	50	3	50	3	50	3	50	3
27	BPA/Avista Exchange	32	12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Entitlement & Supplemental	5	0	4	0	4	0	4	0	0	0	0	0	0	0	0	0	0	0	0	0
29	BPA Res. Exchange	0	0	0	12	47	47	47	47	47	47	47	47	47	47	149	149	149	149	149	149
30	BPA-WNP #3	82	41	82	41	82	41	82	41	82	41	82	41	82	41	82	41	82	41	82	41
31	CSPE	10	5	9	5	9	5	8	1	0	0	0	0	0	0	0	0	0	0	0	0
32	TransAlta-Centralia	200	138	200	143	200	143	200	143	0	0	0	0	0	0	0	0	0	0	0	0
33	Thermal- Kettle Falls	48	45	48	45	48	45	48	45	48	45	48	45	48	45	48	45	48	45	48	45
34	Colstrip	222	191	222	191	222	191	222	191	222	191	222	191	222	191	222	191	222	191	222	191
35	SEMPRA	0	19	0	19	0	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	BPA 5 yr. Purchase	115	115	115	86	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
37	Idaho Purchase	100	100	100	58	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
38	Duke Purchase	100	100	100	58	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
39	MIECO	25	25	25	25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
40	Cinergy Services, Inc.	0	14	0	14	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
41	Energy Services, Inc.	0	50	0	25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
42	Enron	50	50	50	25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
43	TOTAL RESOURCES	2476	1425	2442	1267	2040	944	2039	933	1822	789	1822	785	1771	789	1874	866	1874	866	1874	861
44	SURPLUS (DEFICIT)	-395	-237	-295	-203	-46	-152	-30	-149	-287	-318	-332	-348	-430	-370	-283	-237	-342	-261	-402	-301

## **RE-DISPATCH STUDY**

As the company contemplates the addition of one or more resources to its portfolio it will be faced with a different resource stack and fuel mix. The new resources will have an impact on the resource dispatch sequence because of the fuel supply and marginal costs. The company is using PROSYM to model its resources, to meet its load requirements on an hourly basis, and to assess the dispatch requirements and compatibility of new resources used in conjunction with existing resources, both hydro and thermal. An example of a PROSYM run with a new combined cycle combustion turbine modeled into the company's system is shown in the following charts.

### **Load and Resource Monthly and Hourly Analysis**

#### **Resource Flexibility:**

Flexible generation resources are a key component to meet the requirements of Avista's customers. As depicted in the charts, Avista experiences load changes of 100 MW or more during several hours of each day. Loads must be ramped up and down under a variety of seasonal and load conditions. In order to meet the load, flexible resources (Cabinet Gorge, Noxon Rapids, Long Lake, mid-Columbia contract hydro, and the Rathdrum Combustion turbines) are dispatched. The market today tends to offer only standard heavy load hour and light load hour products that do not meet load shaping or following needs. In the past it was possible to purchase more flexible power at reasonable prices. Physical resources have become more important to shape resources to load and to follow either planned or unplanned load changes.

#### **2004 Study:**

A detailed tabulation of the load and resource requirements study of the year 2004 is shown in the following pages. Avista chose the year 2004 for an in-depth study because, as mentioned before, many of the larger supply and requirements contracts have ended and future requirements change (for the most part) due to load growth.

This study is shown in two parts. The first study shows on and off peak loads and resource requirements monthly under critical and normal hydro conditions. The second study goes into even further detail. Avista created an hourly Surplus-Deficiency duration Curve for the year 2004 using PROSYM to gain the following information. By using the Northwest Power Pool's sixty year hydro generation study for our system, PROSYM runs 720 (sixty years X 12 months/year) hydro scenarios into the forecast net system load, all known contracts, and existing resources. The information gained from this model output shows the company's resource requirements to meet load under many different hydro conditions. This duration curve will be used to analyze how new resource additions will "fit" into the company's requirements without any affect from market conditions. As stated before, standard economic modeling must be performed after dispatch information is gained from PROSYM modeling.

#### **2004 – 2020 Study:**

Hourly system load and resource evaluations for the years 2004, 2010, 2015, and 2020 are also shown. The method used to calculate the surplus and deficiencies for each of these time periods is similar to the method used above. Instead of using 60 years of actual flows Avista inputs the





Table G-4

Avista Utilities																				
System Physical Surplus/(Deficiency)																				
Critical Hydro Conditions																				
Month & Hours	Net System Load	PacifiCorp. Exchange	Spokane Upwr	Contract Resources		BPA Subscrip	BPA WNP #3	Can Ent. Rin	Contract Requirements			Kettle Falls	NE Rairdram	Mid C & Spokane Hydro	Clark Fork Hydro	Total Resource	Total Obligation	Physical Surplus/(Deficiency)	New Flexible Resource Acquisition	Physical Surplus/(Deficiency)
				Small Power	Power				PGE #1	SnrPud	Cogen									
2004																				
Jan HL	1314	-18.8	-11	-4	-4	-47	-82	5	56.25	100	0	-173	94	-242	-918	1475	-557	-270	-287	
Jan LL	1030	0.0	-11	-4	-4	-47	-119	5	-71.5	100	0	-85	-70	-132	-715	1054	-348	-270	-78	
Feb HL	1222	-18.8	-11	-4	-4	-47	-82	5	56.25	100	0	0	-63	-317	-789	1383	-593	-270	-323	
Feb LL	946	0.0	-11	-4	-4	-47	-119	5	-71.5	100	0	0	-46	-169	-643	979	-337	-270	-67	
Mar HL	1113	0.0	-12	-5	-5	-47	-41	5	56.25	100	0	0	59	-299	-709	1274	565	-270	295	
Mar LL	835	0.0	-12	-5	-5	-47	-61	5	-71.50	100	0	0	-43	-156	-571	868	-298	-135	-163	
Apr HL	1049	0.0	-13	-5	-5	-47	-41	5	56.25	100	0	0	-57	-300	-709	1211	-411	-270	-141	
Apr LL	791	0.0	-13	-5	-5	-47	-61	5	-71.50	0	0	0	-43	-204	-620	724	-104	0	-104	
May HL	1046	0.0	-11	-5	-5	-47	0	5	56.25	100	0	0	96	-594	-1000	1208	-208	0	-208	
May LL	788	0.0	-11	-5	-5	-47	0	5	-71.50	0	0	0	-77	-501	-887	722	165	0	165	
Jun HL	1071	0.0	-10	-5	-5	-47	0	5	56.25	100	0	0	104	-700	-962	1232	-270	-270	0	
Jun LL	774	0.0	-10	-5	-5	-47	0	5	-71.50	0	0	0	-89	-632	-926	707	219	0	219	
Jul HL	1050	0.0	-4	-4	-4	-47	0	5	56.25	100	0	-130	-70	-336	-834	1211	-377	-270	-107	
Jul LL	765	0.0	-4	-4	-4	-47	0	5	-71.50	100	0	0	-61	-245	-603	799	-196	-270	74	
Aug HL	1060	0.0	-3	-3	-3	-47	0	5	56.25	100	0	-139	-88	-390	-948	1221	-273	-270	3	
Aug LL	768	0.0	-3	-3	-3	-47	0	5	-71.50	100	0	-70	-67	-158	-582	802	-210	-270	60	
Sep HL	964	0.0	-3	-3	-3	-47	0	5	56.25	100	0	-143	-84	-232	-790	1125	-335	-270	-65	
Sep LL	715	0.0	-3	-3	-3	-47	0	5	-71.50	100	0	-72	-63	-112	-543	748	-205	-270	65	
Oct HL	1079	0.0	-3	-3	-3	-47	0	5	56.25	100	0	-161	-88	-242	-822	1240	-418	-270	-148	
Oct LL	816	0.0	-3	-3	-3	-47	0	5	-71.50	100	0	-70	-69	-111	-546	850	-304	-270	-34	
Nov HL	1173	0.0	-3	-3	-3	-47	-82	5	56.25	100	0	-167	-91	-327	-963	1335	-371	-270	-101	
Nov LL	911	0.0	-3	-3	-3	-47	-119	5	-71.50	100	0	0	-74	-152	-641	945	-304	-270	-34	
Dec HL	1271	0.0	-3	-3	-3	-47	-82	5	56.25	100	0	-171	-116	-429	-1094	1433	-339	-270	-68	
Dec LL	1010	0.0	-3	-3	-3	-47	-119	5	-71.50	100	0	0	-84	-243	-742	1043	-301	-270	-31	
AVE	1007	1.8	-5.7	-3.9	-3.9	-47.0	-41.1	5.0	0.0	88.0	0.0	-61.4	-76.0	-313.1	-790.5	1092.1	-301.6	-222.8	-78.8	
														Ave HLH	-393	-146	-146			
														Ave LLH	-185	-191	6			

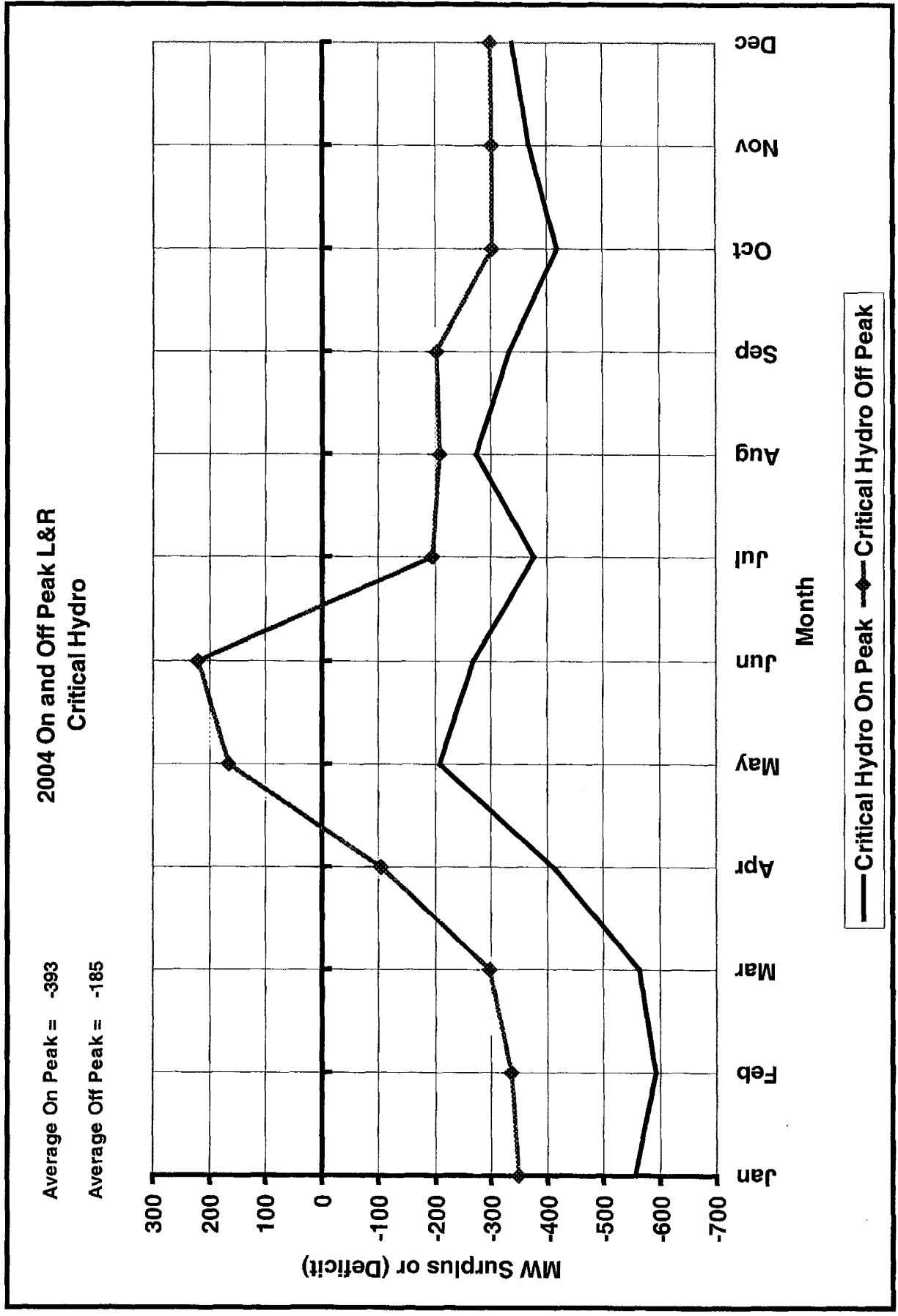
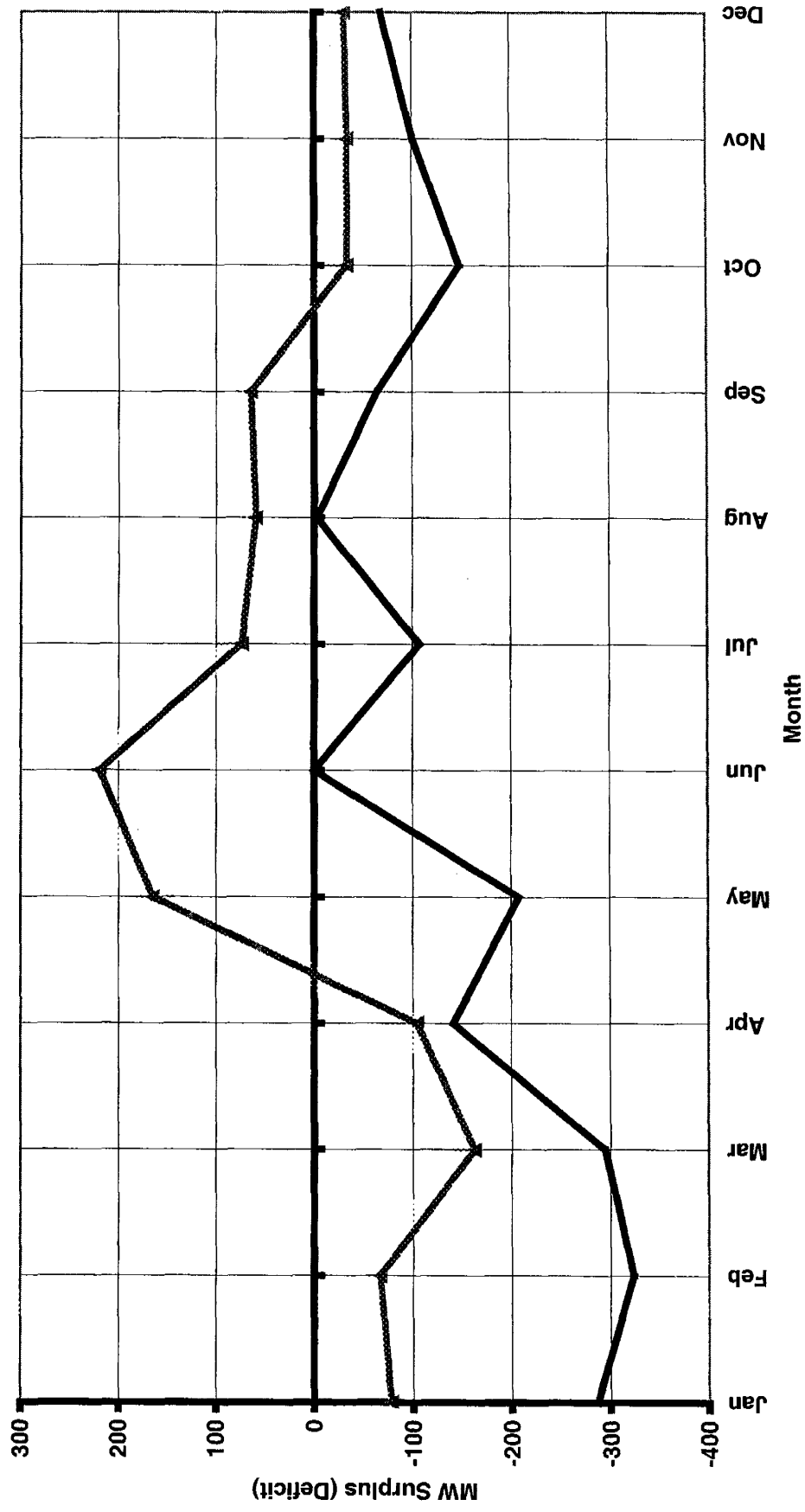


Figure G-1

2004 On and Off Peak L&R  
After New Resource  
Critical Hydro

Average On Peak = -146

Average Off Peak = 6



— Critical Hydro On Peak w/ New Resource    - - - Critical Hydro Off Peak w/ New Resource

Figure G-2

Avista Utilities															Normal Hydro Conditions														
System Physical Surplus/(Deficiency)															2004														
Month & Hours	Net System Load	PacifiCorp Exchange	Spokane Small Upriver Power	Contract Resources			Contract Requirements			Cogen.	Colstrip	Kettle Falls	NE	Rathdrum	Mid C & Spokane Hydro	Clark Fork Hydro	Total Resource Obligation	Physical Surplus/(Deficiency)	Flexible Resource Acquisition	Physical Surplus/(Deficiency)									
				BPA Subscrip	BPA WNP #8	BPA	Can Ent	PGE #	Snopud												Rtn								
2004																													
Jan HL	1314	-18.8	-11	-4	-47	-82	5	56.25	100	0	-200	-47	0	-173	-125	-505	1475	-263	-270	7									
Jan LL	1030	0.0	-11	-4	-47	-119	5	-71.5	100	0	-200	-47	0	-85	-103	-276	1064	-172	-270	98									
Feb HL	1222	-18.8	-11	-4	-47	-82	5	56.25	100	0	-200	-47	0	0	-124	-548	1383	-302	-270	-32									
Feb LL	946	0.0	-11	-4	-47	-119	5	-71.5	100	0	-200	-47	0	0	-103	-292	979	-157	-270	113									
Mar HL	1113	0.0	-12	-5	-47	-41	5	56.25	100	0	-200	-47	0	0	-113	-546	1274	-264	-270	6									
Mar LL	835	0.0	-12	-5	-47	-61	5	-71.50	100	0	-200	-47	0	0	-93	-286	868	-118	-135	17									
Apr HL	1049	0.0	-13	-5	-47	-41	5	56.25	100	0	-200	-47	0	0	-106	-669	1211	-83	-270	187									
Apr LL	791	0.0	-13	-5	-47	-61	5	-71.50	0	0	-200	-47	0	0	-91	-350	724	89	0	89									
May HL	1046	0.0	-11	-5	-47	0	5	56.25	100	0	-200	-47	0	0	-94	-782	1208	-22	0	-22									
May LL	788	0.0	-11	-5	-47	0	5	-71.50	0	0	-200	-47	0	0	-85	-659	722	332	0	332									
Jun HL	1071	0.0	-10	-5	-47	0	5	56.25	100	0	-96	0	0	0	-101	-775	1232	-198	-270	72									
Jun LL	774	0.0	-10	-5	-47	0	5	-71.50	0	0	-96	-47	0	0	-98	-700	707	296	0	296									
Jul HL	1050	0.0	-4	-4	-47	0	5	56.25	100	0	-200	-47	0	-130	-114	-555	1211	-114	-270	156									
Jul LL	765	0.0	-4	-4	-47	0	5	-71.50	100	0	-200	-47	0	0	-112	-405	799	16	-270	286									
Aug HL	1060	0.0	-3	-3	-47	0	5	56.25	100	0	-200	-47	0	-139	-103	-337	1221	-311	-270	-41									
Aug LL	768	0.0	-3	-3	-47	0	5	-71.50	100	0	-200	-47	0	-70	-91	-137	802	-207	-270	63									
Sep HL	964	0.0	-3	-3	-47	0	5	56.25	100	0	-200	-47	0	-143	-87	-326	1125	-237	-270	33									
Sep LL	715	0.0	-3	-3	-47	0	5	-71.50	100	0	-200	-47	0	-72	-72	-157	748	-151	-270	119									
Oct HL	1079	0.0	-3	-3	-47	0	5	56.25	100	0	-200	-47	0	-161	-86	-362	1240	-380	-270	-30									
Oct LL	816	0.0	-3	-3	-47	0	5	-71.50	100	0	-200	-47	0	-70	-76	-166	850	-241	-270	29									
Nov HL	1173	0.0	-3	-3	-47	-82	5	56.25	100	0	-200	-47	0	-167	-101	-449	1335	-240	-270	30									
Nov LL	911	0.0	-3	-3	-47	-119	5	-71.50	100	0	-200	-47	0	0	-93	-208	945	-228	-270	42									
Dec HL	1271	0.0	-3	-3	-47	-82	5	56.25	100	0	-200	-47	0	-171	-117	-454	1433	-313	-270	-43									
Dec LL	1010	0.0	-3	-3	-47	-119	5	-71.50	100	0	-200	-47	0	0	-95	-257	1043	-276	-270	-6									
Ave	1007	-1.8	-5.7	-3.9	47.0	-11.1	5.0	0.0	89.0	0.0	-199.9	-44.8	-4.9	-61.4	-100.1	-437.1	1092.1	-153.5	-222.8	69.3									
															Ave HLH		Ave LLH												
															221		-191												

Table G-5

Average On Peak = 27

Average Off Peak = 123

### 2004 On and Off Peak L&R After New Resource Figure G-3

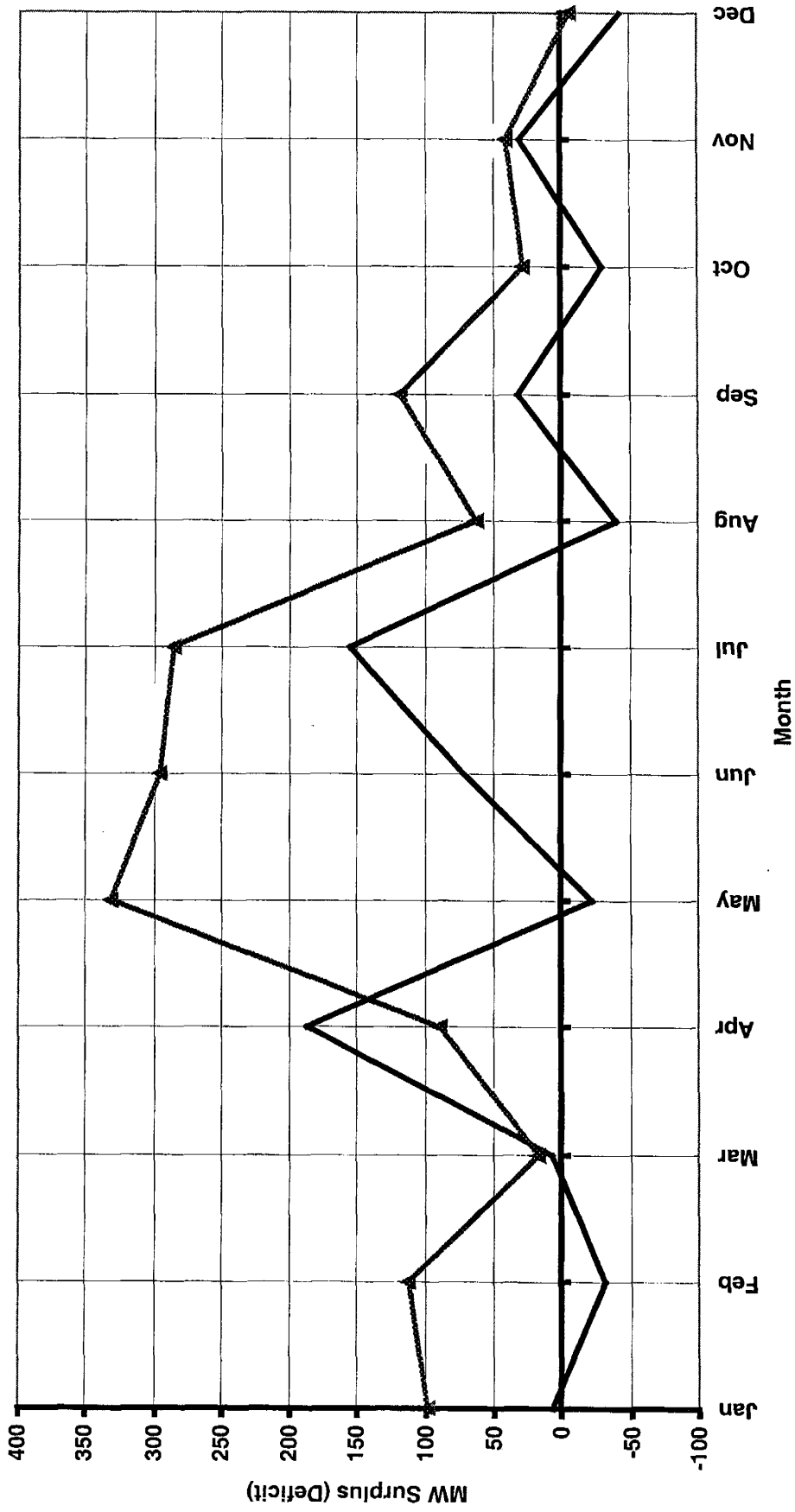


Figure G-4

Daily Load Change Duration (Daily Max minus Daily Min)  
January 1997 - June 2000 Hourly Data

Average Daily Load Change = 402 MW

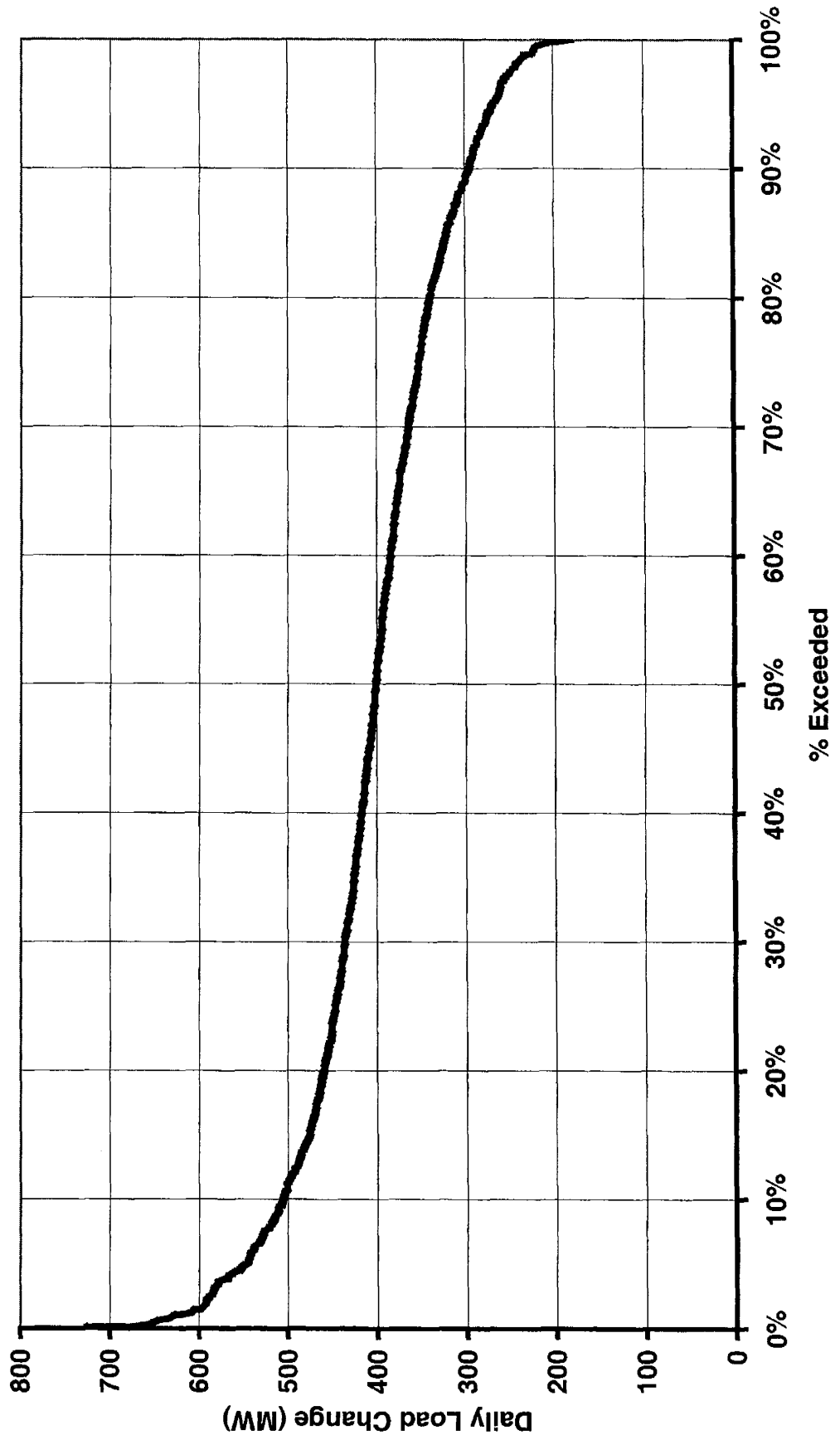
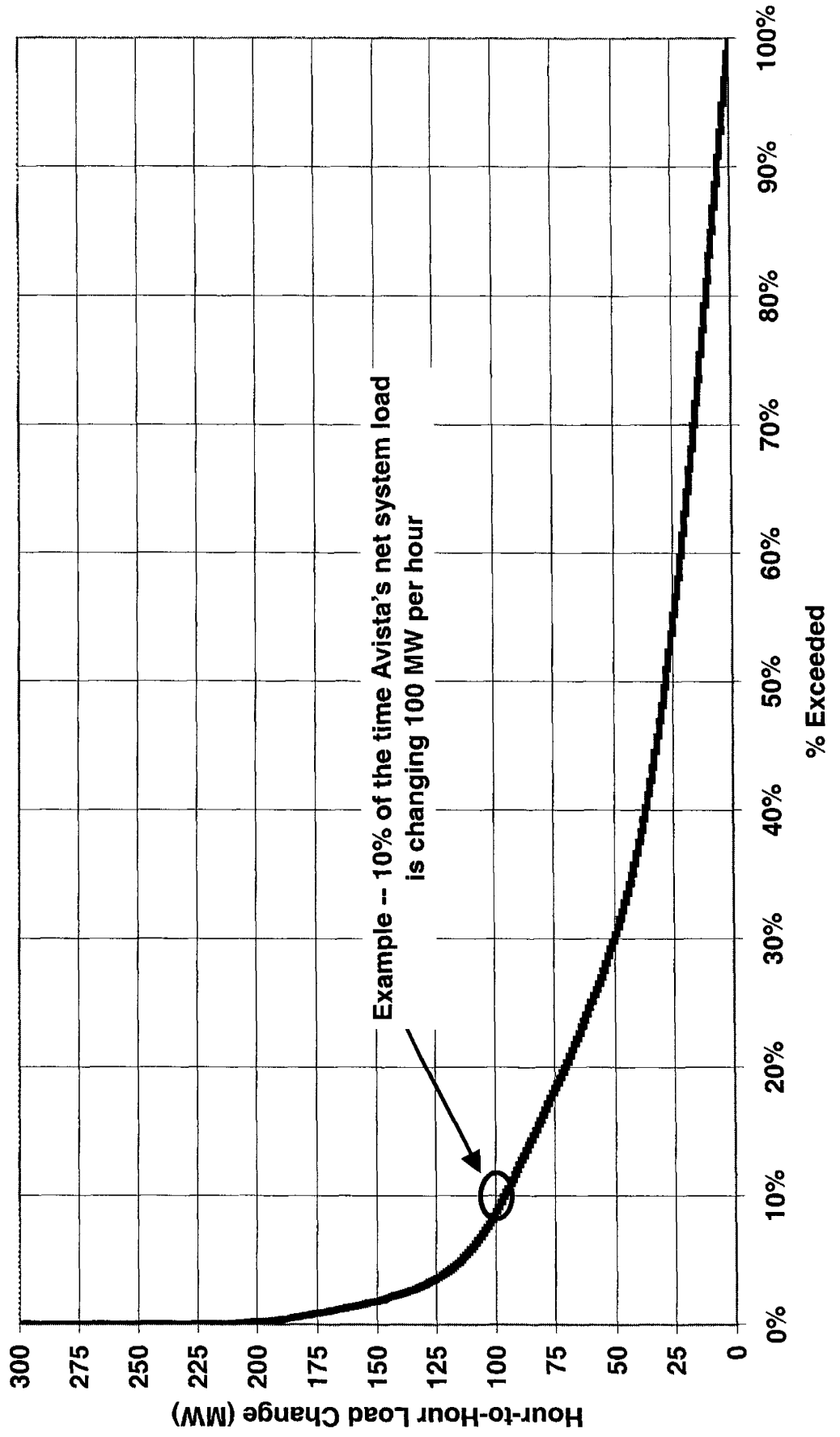


Figure G-5

### Hour-to-Hour Net System Load Change Duration Curve January 1997 - June 2000 Hourly Data

Average Net System Load = 1050 MW



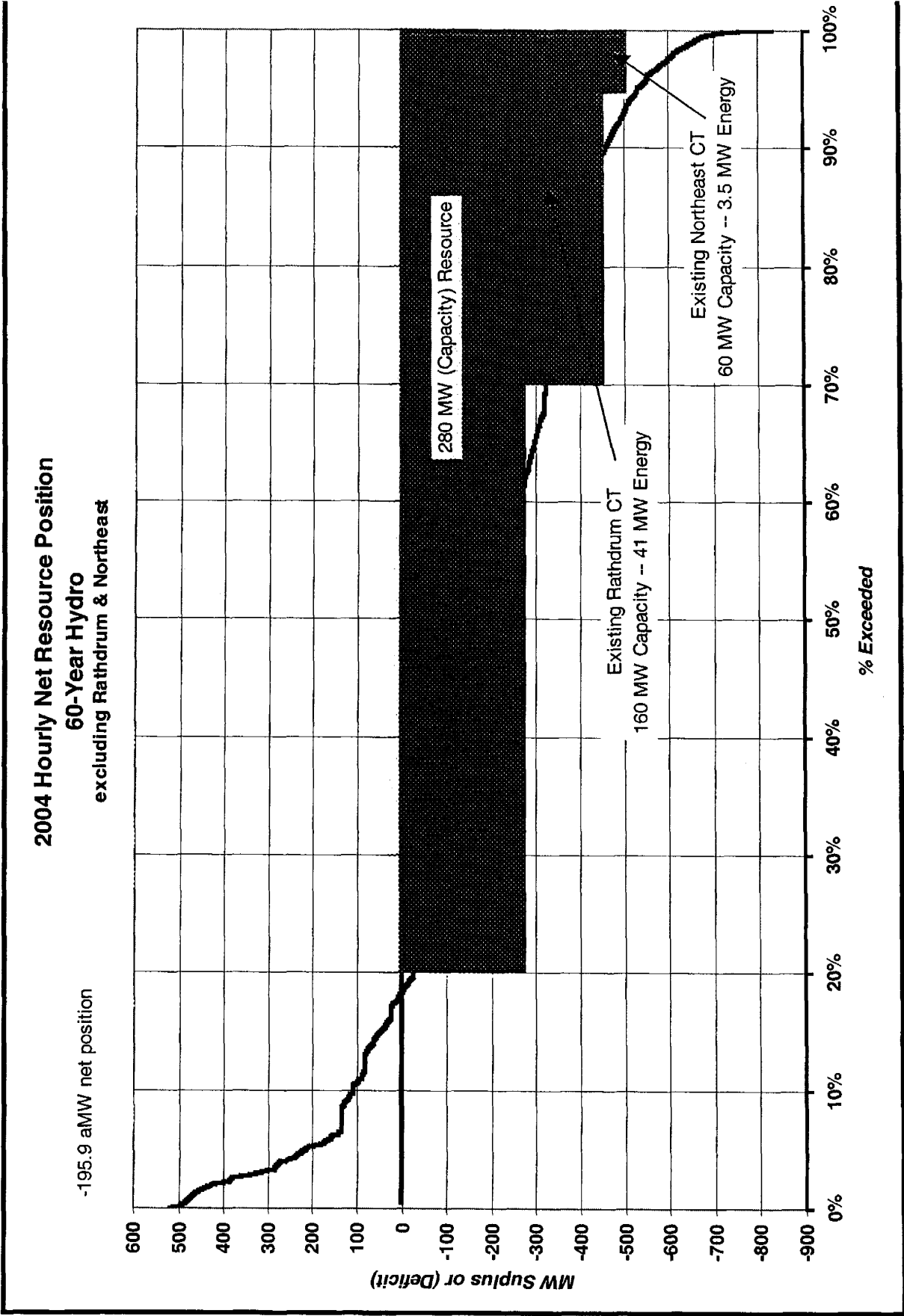


Figure G-6



Figure G-7

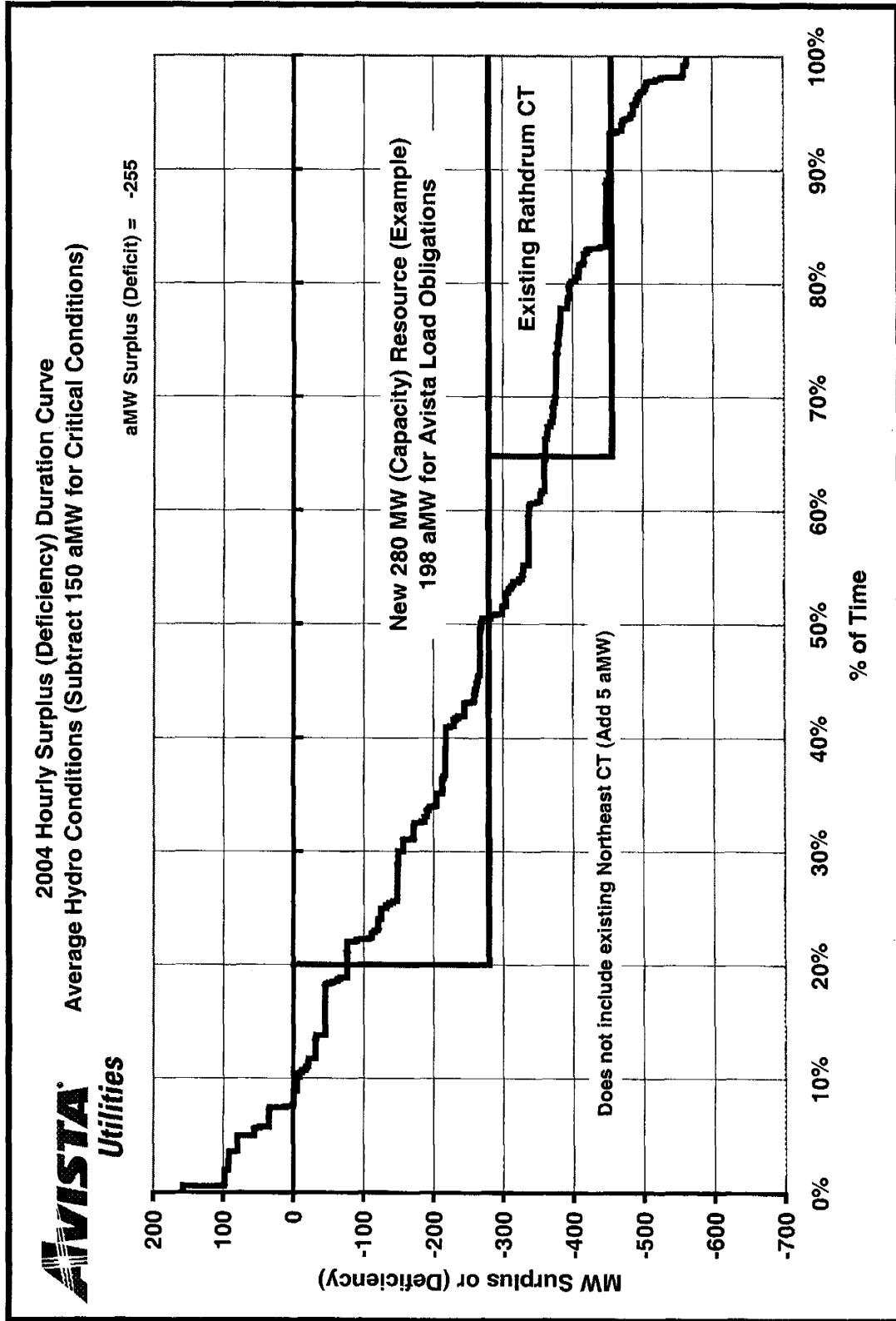


Figure G-8

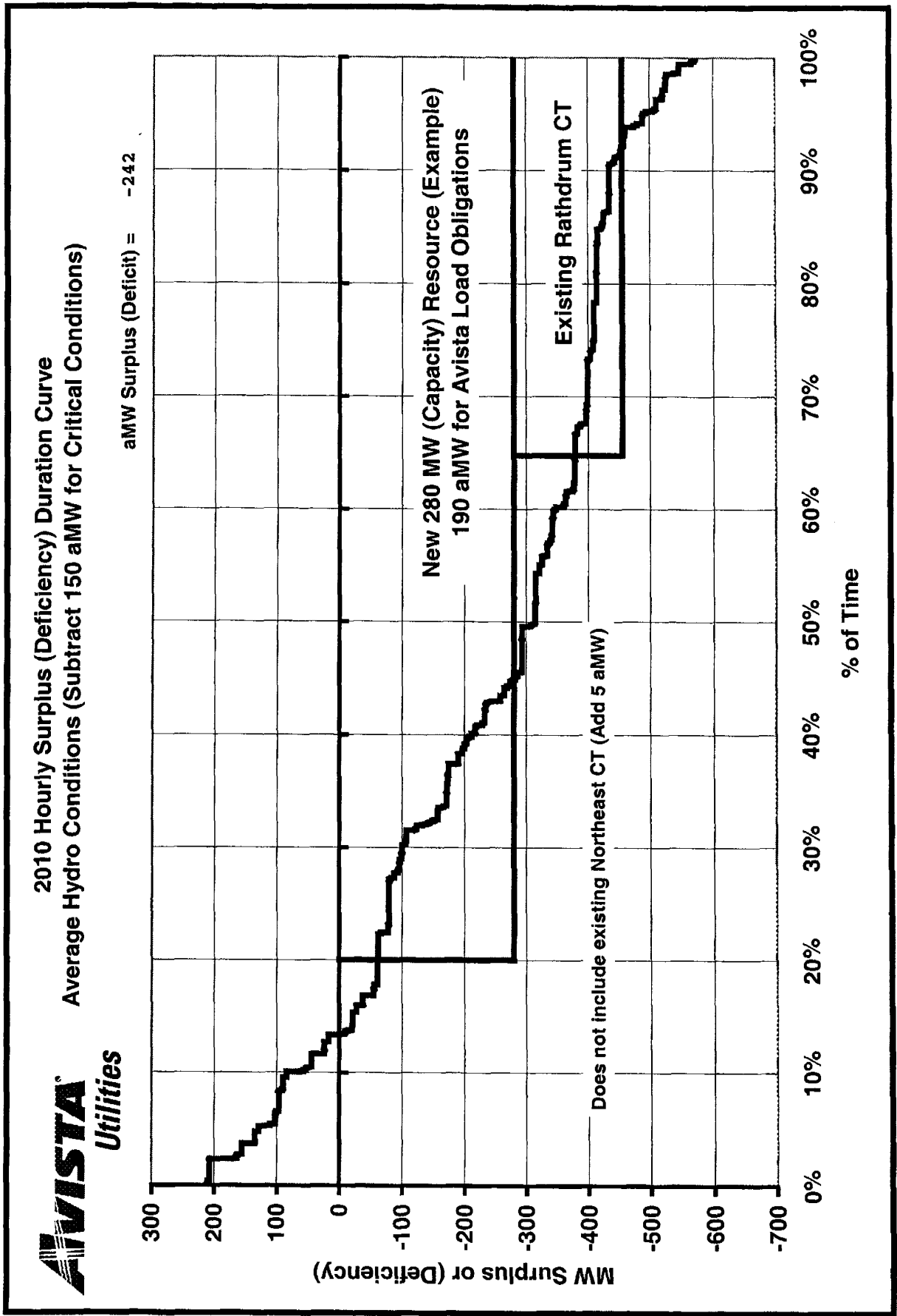


Figure G-9

2015 Hourly Surplus (Deficiency) Duration Curve  
Average Hydro Conditions (Subtract 150 aMW for Critical Conditions)

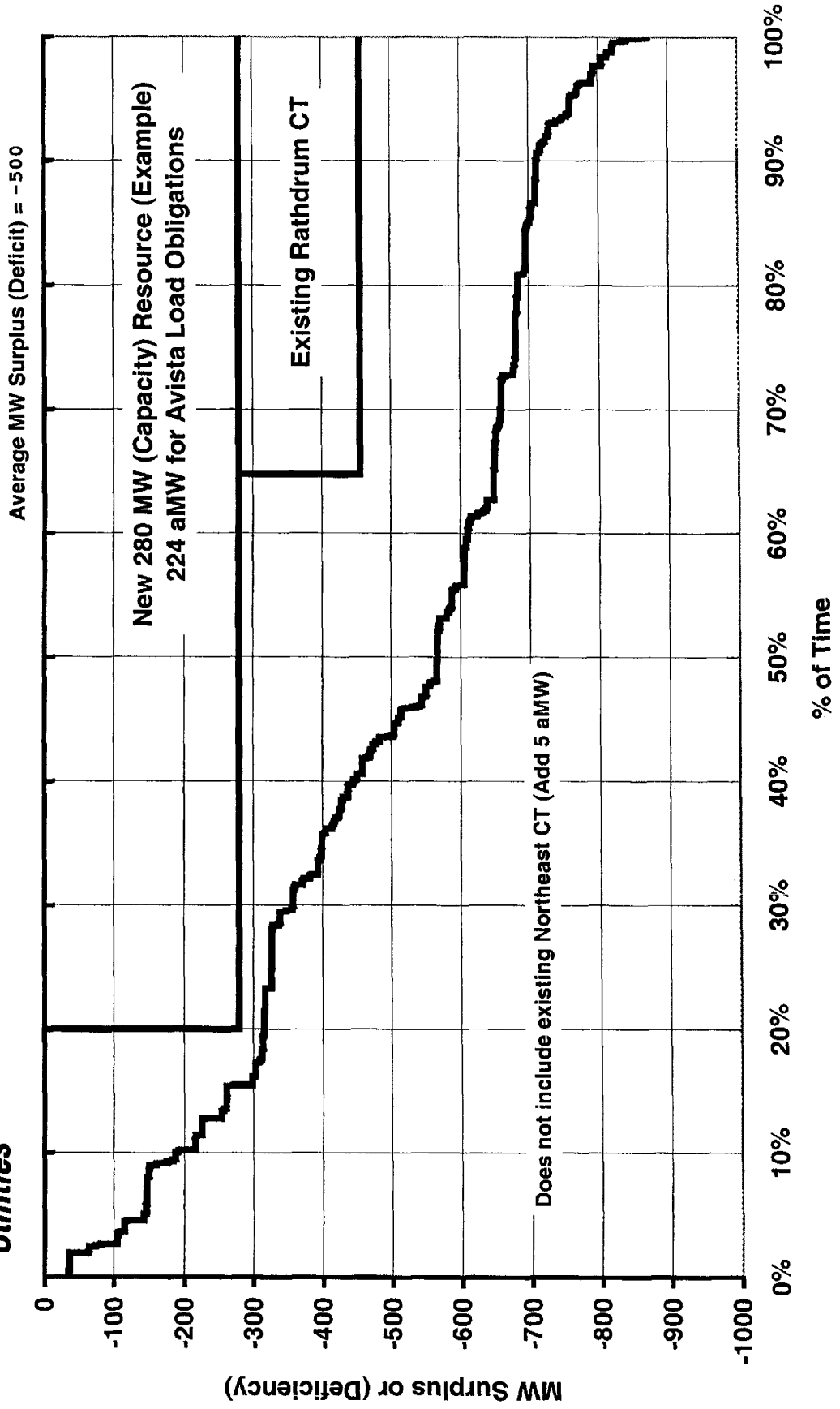
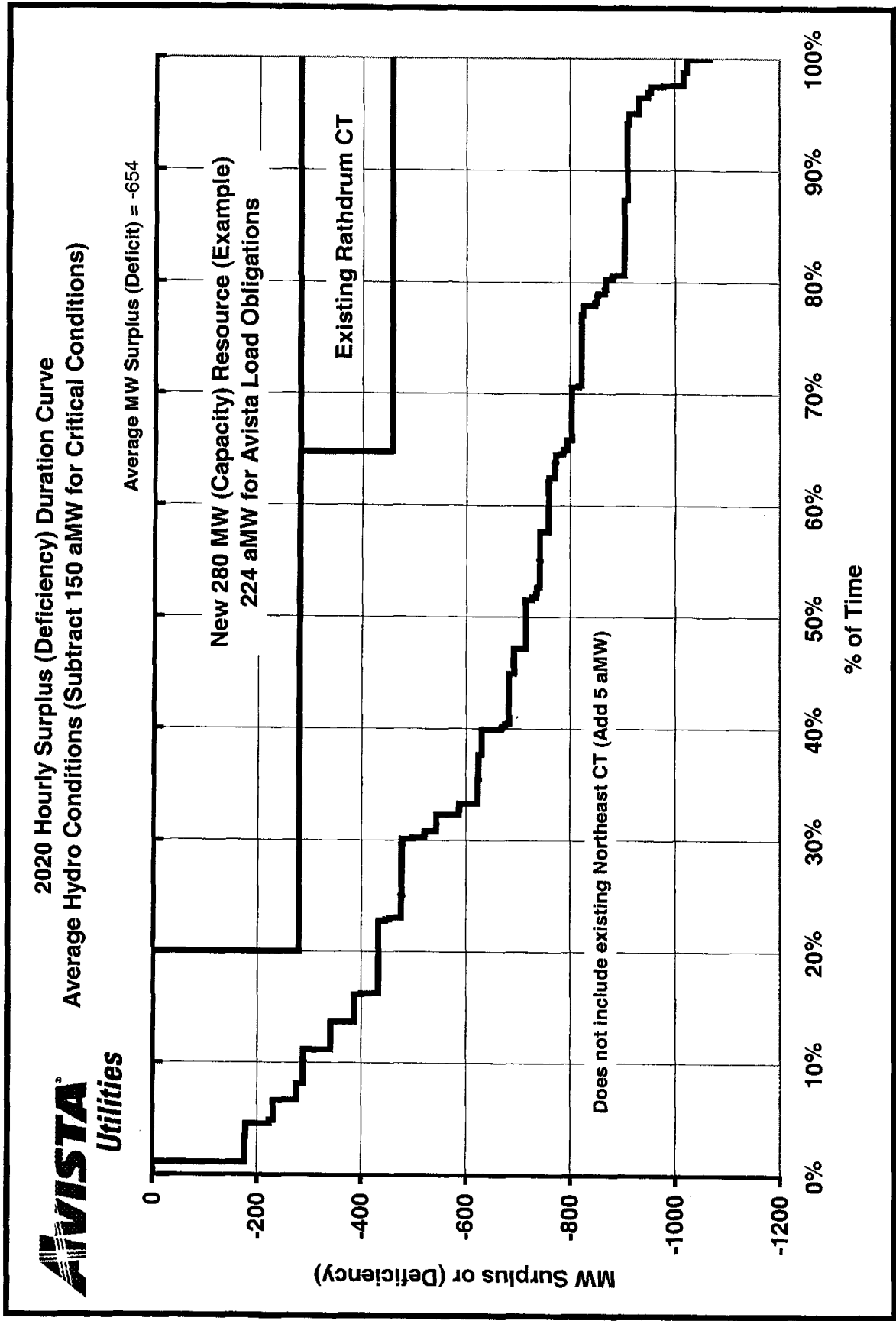


Figure G-10



## CONTRACT INFORMATION

There have been some significant changes in the electric utility industry during the past three years. These changes are a result of competition due to increasing natural gas supplies, technology, open access, retail wheeling opportunities, and customer demands for more energy service options. Within the United States, 24 states have some form of retail open access that covers 60 percent of the nation's population. These changes have affected both the retail side of the business and the wholesale side.

While there has been a lot of wholesale contract activity since the last report, the terms of the more recent contracts have tended to be relatively short. It is interesting to note that most of the purchase and sale agreements terminate by the year 2003, except some of the contracts with BPA and exchanges. There are only three sale contracts that extend beyond the year 2003. These are the PacifiCorp, PGE and Snohomish PUD contracts.

- PacifiCorp and the company entered into a ten-year summer capacity sale for the period June 16 1994 through September 15, 2003 (with PacifiCorp option to extend for up to five years). The company delivers 150 MW of summer capacity with energy purchased at 25 percent load factor based on variable prices.
- Portland General Electric is purchasing from the company 150 MW of capacity through December 31, 2016. The energy associated with the capacity deliveries has to be returned within 168 hours.
- Snohomish PUD purchases 100 MW of firm capacity with a minimum amount of firm energy at 50 percent load factor from the company. The contract ends September 2006.

With retail needs being met by the lowest cost resources, the result will be a continuation of low rates for Avista's customers. Avista will also continue to offer some energy efficiency programs to its customers in order to maintain the DSM infrastructure already in place. Avista provides energy services to customers as a part of the continuing commitment to customers to be a total service company responsive to their needs.

## CONTRACTS WITH UTILITIES

### Bonneville Power Administration/ WWP Exchange

The company and BPA entered into an exchange agreement for the term July 6, 1994 through June 30, 2000. The company will deliver to BPA capacity and energy each month July 6, 1994 through June 30, 1996 and BPA will deliver to the company an equivalent amount of power July 1, 1996 through June 30, 2000.

### Bonneville Power Administration Residential Exchange

BPA has proposed a settlement of power delivery and dollars to cover the Residential Exchange with the investor owned utilities. The initial period of delivery is the BPA five



#### Cogentrix 57 Month

A 5 year interruptible sale commenced October 1, 1995 and terminates September 30, 2000. Cogentrix shall purchase from 46 to 50 MW of capacity between 98% - 100% monthly load factor.

The interruptible product was replaced with firm energy and capacity. This contract has been restructured to a 57-month sale. Starting January 1997 through August the capacity sale is 47 MW between 98% to 100% load factor, on September 1997 the capacity increased to 162 MW through March 1998, on April it decreased to 137 MW and decreased again on October 1998 to 100 MW where it remains through the end of the contract, September 30, 2001.

#### Clark PUD

This sale commenced October 1996 and continues through July 2001. On or before January 1 of each year of the term, Clark will provide to Avista the monthly contract demands it will purchase for that Operating Year. The nomination shall not be greater than 250 MW in any month, or less than 100 MW in any month. The average annual contract demand shall not be less than 175 MW. The total amount of firm energy scheduled by Clark shall equate to a weekly load factor of between 50% and 65%.

#### City of Cheney

This sale is a five year firm sale of 2 MW of capacity at 100% load factor, commencing October 1996 through September 2001, to the City of Cheney.

#### Cinergy Services

Avista is purchasing from Cinergy Services a three year on peak purchase (Monday through Saturday) of 25 MW, starting January 1999.

#### Duke Purchase and Sale

Avista is purchasing at Colstrip 100 MW of firm energy from Duke and selling to Duke at Centralia 100 MW of firm energy. The terms of the agreement is for 100 MW of firm energy at 100% load factor starting January 1, 1999 through July 31, 2001.

#### Eugene Water and Electric Board

Eugene shall purchase 10 MW of capacity with a minimum load factor of 70% up to a maximum of 100%. This is a 5-year agreement, which commenced October 1, 1995 and continues through September 30, 2000. Rates are fixed by contract.

#### Energy Services

This is a four year purchase from Energy Services, Inc. that started July 1, 1997 and goes through June 30, 2001. The energy delivered is 50 MW of firm energy at 100% load factor.

Enron

Avista purchased from Enron two years of 50 MW of firm energy for the period July 1, 1999 to June 30, 2001.

Idaho

Avista is purchasing from Idaho Power 100 MW at 100% load factor for the period August 1, 1998 through July 31, 2001.

Mid-Columbia Purchases

Chelan County PUD:

Rocky Reach Plant

The company has been receiving 3.9% or 32 MW of capacity from Rocky Reach Hydro Plant since 1961, but the debt interest and repayment charges were not a cost factor until 1963. The contract is in effect until November 1, 2011, and Avista's participation was reduced to 2.9% (23 MW) on July 1, 1977, for the remainder of the contract.

The company signed an amendment to the Rocky Reach Power Sales contract June 1, 1968, which provides for company participation in the power output of four additional units in the fall of 1971. The company's percentage share in these additional units will be the same as the initial seven units and currently is 2.9% or 14 MW.

Douglas County PUD:

Wells Plant

The company has a 50-year contract for 5.6% of the Wells Hydro plant power. The power became available in 1967; however, it was assigned to other utilities until September 1, 1972, at which time the company started receiving this power. The PUD may withdraw, within certain limits, a portion of the plant output but cannot reduce the company's share below 3.5%. Avista's participation reduced to 3.5% (29 MW) on September 1, 1997, for the remainder of the contract. The contract is in effect until August 31, 2018.

Grant County PUD:

Priest Rapids Plant

The company first received power from Priest Rapids Hydro Plant in 1959, but debt interest and repayment charges didn't become a factor until 1961. The company's share of this plant's power was initially 11%. Reductions in the company's share were made by the PUD in predetermined maximum amounts on five years' notice. The company's share was reduced to 6.1% on September 1, 1983 and will remain 6.1% (55 MW) until the end of the contract. The contract is in effect until October 31, 2005.

Wanapum Plant

The company received 13.1% of capacity commencing in 1964 but paid only its share of the operating charges. However, debt interest and repayment charges commenced January 1, 1965. Similar to the Priest Rapids contract, the company's share was reduced to 8.2% (75 MW) on September 1, 1983 until the end of the contract. The contract is in effect until October 31, 2009.



### MIECO

The MIECO purchase is for 25 MW of firm energy at 100% load factor. It is a two year agreement starting January 1, 2000 through December 31, 2001.

### Montana Power

Avista is selling to Montana 100 MW at Colstrip at 100% load factor for the period August 1, 1998 through July 31, 2001.

### Nichols Pumping

Avista provides energy at Colstrip for Nichols pumping with the other plant owners providing reimbursement plus an adder with PGE returning the energy at mid-Columbia.

### PacifiCorp 1994

The company and PacifiCorp entered into a ten year summer capacity sale for the period June 16, 1994 through September 15, 2003 (with PacifiCorp option to extend for up to five years). Delivery to PacifiCorp is June 16 through September 15, with PacificCorp option to change the term to June 1 through September 30 by giving prior notice. The company will deliver 100 MW in 1994 and 1995 and 150 MW in 1996 and thereafter. Energy will be purchased at 25 percent load factor based on variable prices.

### PacifiCorp Exchange

The company and PacifiCorp entered into a 15 year, 50 MW exchange, from June 16, 1994 through March 31, 2009. Delivery season is June 16 through September 15 in the summer to PacifiCorp and December 1 through February 28 in the winter to WWP. The energy exchanged is 27,600 MWh per season and the monthly load factor can vary between 0 to 50 percent. Either party may terminate the exchange with three years notice, after March 31, 2004.

### Pend Oreille PUD

Avista is selling to Pend Oreille for the term January 1, 1998 to July 31, 2000 6 MW of firm energy at 100% load factor.

### Portland General Electric

The company is selling to PGE 100 MW of capacity, ten hours per day, fifty heavyload hours per week for the term March 1, 1992 through October 31, 1994. Within 168 hours the energy associated with the capacity deliveries shall be returned. In June 1992 the company signed a long-term capacity sale with PGE for an additional 50 MW beginning November 1992 through October 1994, and 150 MW for the period starting November 1, 1994 through December 31, 2016.

### Portland General Electric

Avista is selling to PGE two separate one year deals with different terms of 25 MW of energy at 100% load factor for the period January 1, 2000 through December 31, 2001.



## GENERATION PERFORMANCE DATA

This section includes five years of historical data relating to WWP's generation and power purchased from independent developers under PURPA regulations. It also includes a monthly summary of economy exchanges, purchases and sales. Resources are identified within one of the following categories:

1. Hydroelectric
  - Noxon Rapids
  - Cabinet Gorge
  - Post Falls
  - Upper Falls
  - Monroe Street
  - Nine Mile
  - Long Lake
  - Little Falls
  
2. Coal-Fired
  - Colstrip No. 3
  - Colstrip No. 4
  
3. Other
  - Kettle Falls
  
4. PURPA - Hydroelectric
  - Upriver Power Project
  - Big Sheep Creek
  - Jim Ford Creek
  - John Day Creek
  - Meyers Falls
  
5. PURPA - Thermal
  - Minnesota Methane
  
6. Economy Purchases/Sales
  - Based on hydro and load conditions at time of purchase or sale.

NOTE: PURPA facilities that produce less than 1500 Mwh/year are not listed.

Table G-6

Hydro Plants

Noxon Rapids

FERC License Expiration Date : 03/01/2046

Rated Capacity: (Peak in MW)		Total	No. 1	No. 2	No. 3	No. 4	No. 5	
		528	102	102	102	92	130	
<u>Year</u>	<u>Month</u>	<u>Forced Outage Rate</u>	<u>Equivalent Availability Factor</u>		<u>Year</u>	<u>Month</u>	<u>Forced Outage Rate</u>	<u>Equivalent Availability Factor</u>
1995	Jan	0.00	100.00		1998	Jan	0.98	99.40
	Feb	0.00	100.00			Feb	0.00	100.00
	Mar	0.00	92.63			Mar	1.08	97.53
	Apr	5.00	80.95			Apr	0.37	99.82
	May	0.00	97.82			May	1.17	98.62
	Jun	0.00	100.00			Jun	0.00	100.00
	Jul	0.00	100.00			Jul	0.00	99.57
	Aug	0.00	100.00			Aug	8.21	96.00
	Sep	0.00	100.00			Sep	2.99	92.14
	Oct	1.00	91.47			Oct	4.35	90.39
	Nov	0.00	99.99			Nov	0.38	98.37
	Dec	0.00	99.92			Dec	0.35	99.74
1996	Jan	0.00	99.96		1999	Jan	0.02	99.88
	Feb	0.00	100.00			Feb	0.01	95.27
	Mar	0.00	89.44			Mar	0.00	93.12
	Apr	0.00	100.00			Apr	0.26	99.82
	May	0.00	99.87			May	0.00	100.00
	Jun	0.00	100.00			Jun	0.00	99.67
	Jul	0.00	100.00			Jul	0.00	99.86
	Aug	3.00	98.77			Aug	0.00	100.00
	Sep	0.00	100.00			Sep	N/A	N/A
	Oct	0.00	99.95			Oct	2.66	75.74
	Nov	0.00	100.00			Nov	0.00	80.00
	Dec	1.00	99.33			Dec	0.03	91.19
1997	Jan	0.81	99.48					
	Feb	0.18	99.17					
	Mar	0.11	88.26					
	Apr	0.00	99.89					
	May	0.05	99.95					
	Jun	0.00	100.00					
	Jul	0.19	99.62					
	Aug	0.00	100.00					
	Sep	2.20	98.99					
	Oct	28.83	82.31					
	Nov	0.00	100.00					
	Dec	0.00	100.00					

Equivalent Availability Factor = Availability Factor = (Available Unit Days/Period Unit Days) \* 100.

Forced Outage Rate = (Forced Outage Unit Days/(Service Unit Days + Forced Outage Unit Days)) \* 100.

Table G-7

Hydro Plants

Cabinet Gorge

FERC License Expiration Date : 03/01/2046

Rated Capacity: Total No. 1 No. 2 No. 3 No. 4  
(Peak in MW) 236 63.50 57.5 57.5 57.5

<u>Year</u>	<u>Month</u>	<u>Forced Outage Rate</u>	<u>Equivalent Availability Factor</u>	<u>Year</u>	<u>Month</u>	<u>Forced Outage Rate</u>	<u>Equivalent Availability Factor</u>
1995	Jan	0.00	99.95	1998	Jan	1.11	97.86
	Feb	1.00	97.40		Feb	0.02	99.27
	Mar	0.00	75.92		Mar	0.04	99.98
	Apr	1.00	95.70		Apr	0.00	100.00
	May	0.00	99.75		May	0.06	99.94
	Jun	0.00	100.00		Jun	0.01	99.99
	Jul	1.00	99.05		Jul	0.00	100.00
	Aug	2.00	99.06		Aug	0.01	100.00
	Sep	0.00	100.00		Sep	0.00	99.88
	Oct	0.00	99.60		Oct	0.08	91.84
	Nov	0.00	99.84		Nov	0.00	99.82
	Dec	0.00	100.00		Dec	0.32	99.63
1996	Jan	0.17	99.85	1999	Jan	0.00	100.00
	Feb	0.00	99.81		Feb	0.00	95.27
	Mar	0.00	100.00		Mar	0.00	100.00
	Apr	0.00	100.00		Apr	0.00	100.00
	May	1.00	99.00		May	0.01	99.99
	Jun	0.00	100.00		Jun	0.00	100.00
	Jul	0.00	100.00		Jul	0.05	99.96
	Aug	0.00	99.76		Aug	0.51	99.74
	Sep	0.00	82.00		Sep	0.00	100.00
	Oct	0.00	91.00		Oct	0.00	98.86
	Nov	1.00	99.40		Nov	0.00	100.00
	Dec	0.00	99.51		Dec	0.00	100.00
1997	Jan	0.00	100.00				
	Feb	0.00	100.00				
	Mar	0.00	99.17				
	Apr	0.00	100.00				
	May	0.00	100.00				
	Jun	0.00	100.00				
	Jul	0.00	100.00				
	Aug	0.03	99.84				
	Sep	0.00	87.00				
	Oct	0.96	80.33				
	Nov	0.01	99.85				
	Dec	0.00	100.00				

Equivalent Availability Factor = Availability Factor = (Available Unit Days/Period Unit Days) \* 100.

Forced Outage Rate = (Forced Outage Unit Days/(Service Unit Days + Forced Outage Unit Days)) \* 100.

Table G-8

**Hydro Plants**

**Post Falls**

FERC License Expiration Date : 7/31/2007

Rated Capacity:	Total	No. 1	No. 2	No. 3	No. 4	No. 5	No.6
(Peak in MW)	18.0	2.9	2.9	2.9	2.9	2.9	3.5

**Upper Falls**

FERC License Expiration Date : 7/31/2007

Rated Capacity:	Total	No. 1
(Peak in MW)	10.2	10.2

**Monroe Street**

FERC License Expiration Date : 7/31/2007

Rated Capacity:	Total	No. 1
(Peak in MW)	14.8	14.8

**Nine Mile**

FERC License Expiration Date : 7/31/2007

Rated Capacity:	Total	No. 1	No. 2	No. 3	No. 4
(Peak in MW)	24.5	4.1	4.1	8.1	8.2

**Long Lake**

FERC License Expiration Date : 7/31/2007

Rated Capacity:	Total	No. 1	No. 2	No. 3	No. 4
(Peak in MW)	88.0	22.0	22.0	22.0	22.0

**Little Falls**

FERC License Expiration Date : NA (License not required)

Rated Capacity:	Total	No. 1	No. 2	No. 3	No. 4
(Peak in MW)	36.0	9.0	9.0	9.0	9.0

Maintenance and outage records for the above plants are not computerized and exist in log style handwritten form. It would take many man-hours to obtain the necessary data to determine accurate forced outage and availability data. Because of this, five years of data is not included. The data is available for inspection or recording at any time.

Table G-9

## Coal-Fired Plants

Colstrip No. 3

Rated Capacity = 700 MW

Service Date = 1/10/1984

Design Plant Life = 35 years

WWP's Share = 15%

<u>Year</u>	<u>Month</u>	Forced	Equivalent	<u>Year</u>	<u>Month</u>	Forced	Equivalent
		Outage	Availability			Outage	Availability
		<u>Rate</u>	<u>Factor</u>			<u>Rate</u>	<u>Factor</u>
1995	Jan	2.92	87.70	1998	Jan	8.51	84.98
	Feb	1.57	97.95		Feb	15.19	85.01
	Mar	0.09	95.09		Mar	8.22	91.97
	Apr	0.00	99.30		Apr	0.00	86.53
	May	3.31	58.86		May	0.09	100.00
	Jun	1.91	19.21		Jun	0.00	100.00
	Jul	10.10	77.05		Jul	0.00	99.70
	Aug	5.39	94.21		Aug	13.14	87.08
	Sep	0.09	99.55		Sep	0.00	97.95
	Oct	0.07	91.80		Oct	27.42	71.73
	Nov	0.00	94.16		Nov	0.00	99.99
	Dec	0.00	100.00		Dec	0.00	99.61
1996	Jan	0.14	99.86	1999	Jan	14.65	82.50
	Feb	0.93	99.49		Feb	27.07	72.23
	Mar	0.00	100.00		Mar	11.34	86.98
	Apr	0.00	99.31		Apr	0.18	98.74
	May	0.00	99.80		May	0.00	69.43
	Jun	16.41	83.51		Jun	0.15	99.85
	Jul	0.00	99.86		Jul	17.37	81.59
	Aug	7.56	92.17		Aug	4.43	92.76
	Sep	9.29	90.71		Sep	0.10	90.98
	Oct	0.91	98.91		Oct	0.36	95.36
	Nov	5.19	91.42		Nov	18.77	79.71
	Dec	9.43	90.71		Dec	0.00	98.22
1997	Jan	10.00	67.36				
	Feb	0.75	99.44				
	Mar	3.74	95.71				
	Apr	0.00	0.00				
	May	0.00	58.78				
	Jun	0.47	98.48				
	Jul	1.95	97.88				
	Aug	8.67	91.17				
	Sep	13.75	86.08				
	Oct	0.00	99.95				
	Nov	38.29	61.58				
	Dec	0.00	99.57				

Note: WWP uses 111 MW/unit based on an over pressure mode of operation.

Forced Outage Rate:

Forced Outage Hours/(Service hours + Forced Outage Hours) \* 100 (%).

Equivalent Availability Factor:

$$\frac{\text{Available Hours} - [(\text{Derated Hours} * \text{Size of Reduction}) / \text{Maximum Capacity}] * 100 (\%)}{\text{Period Hours}}$$

Table G-10

**Coal-Fired Plants**

**Colstrip No.4**

Rated Capacity = 700 MW  
 Service Date = 4/6/1986  
 Design Plant Life = 35 years  
 WWP's Share = 15%

<u>Year</u>	<u>Month</u>	<u>Forced Outage Rate</u>	<u>Equivalent Availability Factor</u>	<u>Year</u>	<u>Month</u>	<u>Forced Outage Rate</u>	<u>Equivalent Availability Factor</u>
1995	Jan	0.00	98.84	1998	Jan	0.00	98.11
	Feb	0.00	99.99		Feb	0.00	99.97
	Mar	0.00	99.10		Mar	0.00	95.58
	Apr	33.01	23.86		Apr	0.00	91.99
	May	34.69	64.72		May	0.12	47.40
	Jun	8.04	92.20		Jun	22.18	77.82
	Jul	0.00	95.09		Jul	7.22	93.83
	Aug	1.21	97.86		Aug	0.29	85.84
	Sep	15.94	69.29		Sep	0.25	90.99
	Oct	9.98	90.00		Oct	0.00	99.98
	Nov	0.32	95.05		Nov	25.28	74.52
	Dec	0.00	100.00		Dec	6.15	93.98
1996	Jan	0.32	99.68	1999	Jan	1.97	93.95
	Feb	0.11	99.89		Feb	0.28	98.51
	Mar	31.43	79.72		Mar	9.33	89.78
	Apr	0.00	100.00		Apr	0.40	98.29
	May	100.00	77.42		May	0.12	97.78
	Jun	0.00	0.00		Jun	0.00	59.90
	Jul	32.62	52.93		Jul	0.50	72.31
	Aug	2.58	97.21		Aug	0.07	94.22
	Sep	16.85	83.15		Sep	0.00	98.71
	Oct	0.77	99.23		Oct	0.20	98.85
	Nov	0.00	73.92		Nov	0.00	99.89
	Dec	6.36	92.52		Dec	0.00	92.27
1997	Jan	0.00	98.42				
	Feb	0.15	99.66				
	Mar	0.00	100.00				
	Apr	0.83	48.39				
	May	2.58	93.51				
	Jun	5.95	96.85				
	Jul	21.09	78.83				
	Aug	14.84	84.24				
	Sep	0.00	92.78				
	Oct	0.00	89.90				
	Nov	0.00	99.92				
	Dec	0.37	99.58				

Note: WWP uses 111 MW/unit based on an over pressure mode of operation.



**Table G-11**

**Other Resources**

**Kettle Falls**

Rated Capacity =47 MW

Service Date = 12/1/1983

Design Plant Life = 35 years

<u>Year</u>	<u>Month</u>	Forced Outage <u>Rate</u>	Availability <u>Factor</u>	<u>Year</u>	<u>Month</u>	Forced Outage <u>Rate</u>	Availability <u>Factor</u>
1995	Jan	0.00	100.00	1998	Jan	0.00	100.00
	Feb	0.00	100.00		Feb	4.40	95.60
	Mar	9.07	90.64		Mar	0.05	96.47
	Apr	0.00	100.00		Apr	0.00	100.00
	May	0.00	29.03		May	0.00	100.00
	Jun	0.00	100.00		Jun	0.00	0.00
	Jul	0.00	100.00		Jul	0.33	95.22
	Aug	0.12	99.88		Aug	0.25	99.75
	Sep	2.04	97.94		Sep	0.60	99.40
	Oct	2.76	97.37		Oct	0.52	99.61
	Nov	4.07	97.34		Nov	0.00	100.00
	Dec	0.00	100.00		Dec	2.81	97.19
1996	Jan	0.00	100.00	1999	Jan	0.11	99.89
	Feb	0.00	100.00		Feb	0.54	99.17
	Mar	0.00	100.00		Mar	0.48	99.64
	Apr	0.00	100.00		Apr	0.16	99.87
	May	0.00	100.00		May	0.00	100.00
	Jun	0.00	60.69		Jun	1.40	62.28
	Jul	0.56	99.44		Jul	0.19	99.85
	Aug	3.39	96.61		Aug	2.83	97.17
	Sep	0.00	100.00		Sep	1.97	98.03
	Oct	0.00	100.00		Oct	30.02	69.98
	Nov	0.95	99.05		Nov	0.59	99.41
	Dec	0.81	99.19		Dec	24.01	75.99
1997	Jan	0.12	99.88				
	Feb	0.77	99.51				
	Mar	0.00	100.00				
	Apr	12.23	86.65				
	May	8.38	88.69				
	Jun	36.17	17.63				
	Jul	4.59	95.98				
	Aug	11.88	88.12				
	Sep	7.24	92.76				
	Oct	3.27	96.86				
	Nov	25.54	74.46				
	Dec	2.17	97.89				

Availability Factor: (Available Hours/Period Hours) \* 100 (%).

Table G-12

**PURPA Hydroelectric Plants**

**John Day Creek Hydroelectric Project/David Cereghino**

Rated Capacity = 900 kW  
 Hours Connected to System = Not Available  
 Level of Dispatchability = none  
 Expiration Date = 9/21/2022

<u>Year</u>	<u>Month</u>	<u>Generation - MWh</u>	<u>Year</u>	<u>Month</u>	<u>Generation - MWh</u>
1995	Jan	60	1998	Jan	156
	Feb	79		Feb	142
	Mar	154		Mar	110
	Apr	129		Apr	141
	May	367		May	150
	Jun	427		Jun	428
	Jul	440		Jul	425
	Aug	417		Aug	430
	Sep	245		Sep	401
	Oct	246		Oct	307
	Nov	209		Nov	292
	Dec	295		Dec	268
1996	Jan	240	1999	Jan	246
	Feb	273		Feb	206
	Mar	327		Mar	148
	Apr	407		Apr	268
	May	419		May	286
	Jun	429		Jun	423
	Jul	426		Jul	395
	Aug	394		Aug	438
	Sep	296		Sep	354
	Oct	224		Oct	273
	Nov	195		Nov	202
	Dec	184		Dec	166
1997	Jan	183			
	Feb	202			
	Mar	140			
	Apr	230			
	May	302			
	Jun	430			
	Jul	429			
	Aug	435			
	Sep	419			
	Oct	314			
	Nov	252			
	Dec	226			

Scheduled energy not metered energy.

Table G-13

## PURPA Hydroelectric Plants

Jim Ford Creek Power Project/Ford Hydro Limited Partnership

Rated Capacity = 1,500 kW

Hours Connected to System = Not Available

Level of Dispatchability = none

Expiration Date = 4/14/2023

<u>Year</u>	<u>Month</u>	<u>Generation - MWh</u>	<u>Year</u>	<u>Month</u>	<u>Generation - MWh</u>
1995	Jan	702	1998	Jan	730
	Feb	826		Feb	639
	Mar	950		Mar	894
	Apr	679		Apr	774
	May	429		May	516
	Jun	227		Jun	554
	Jul	34		Jul	433
	Aug	1		Aug	254
	Sep	0		Sep	51
	Oct	147		Oct	0
	Nov	591		Nov	0
	Dec	613		Dec	360
1996	Jan	857	1999	Jan	587
	Feb	690		Feb	1,040
	Mar	696		Mar	665
	Apr	1,041		Apr	973
	May	881		May	942
	Jun	109		Jun	463
	Jul	0		Jul	84
	Aug	0		Aug	0
	Sep	0		Sep	0
	Oct	0		Oct	0
	Nov	68		Nov	3
	Dec	464		Dec	57
1997	Jan	464			
	Feb	858			
	Mar	870			
	Apr	1,018			
	May	983			
	Jun	553			
	Jul	183			
	Aug	254			
	Sep	0			
	Oct	0			
	Nov	0			
	Dec	0			

Table G-14

PURPA Hydroelectric Plants

Big Sheep Hydroelectric Project/Sheep Creek Hydro, Inc.

Rated Capacity = 1,500 kW

Hours Connected to System = Not Available

Level of Dispatchability = none

Expiration Date = 6/4/2021

<u>Year</u>	<u>Month</u>	<u>Generation-MWh</u>	<u>Year</u>	<u>Month</u>	<u>Generation-MWh</u>
1995	Jan	174	1998	Jan	898
	Feb	526		Feb	469
	Mar	1,173		Mar	830
	Apr	1,071		Apr	1,218
	May	1,265		May	988
	Jun	1,157		Jun	1,066
	Jul	841		Jul	1,221
	Aug	293		Aug	575
	Sep	134		Sep	458
	Oct	199		Oct	139
	Nov	374		Nov	176
	Dec	912		Dec	317
1996	Jan	913	1999	Jan	695
	Feb	674		Feb	748
	Mar	1,053		Mar	695
	Apr	1,139		Apr	1,142
	May	1,182		May	1,029
	Jun	1,045		Jun	1,121
	Jul	1,090		Jul	1,150
	Aug	406		Aug	1,076
	Sep	157		Sep	703
	Oct	139		Oct	254
	Nov	150		Nov	161
	Dec	104		Dec	654
1997	Jan	104			
	Feb	232			
	Mar	352			
	Apr	754			
	May	1,170			
	Jun	927			
	Jul	1,185			
	Aug	990			
	Sep	676			
	Oct	717			
	Nov	1,126			
	Dec	985			

Table G-15

**PURPA Hydroelectric Plants**  
**Upriver Power Project/City of Spokane**

Rated Capacity = 15,700 kW  
 Hours Connected to System = Not Available  
 Level of Dispatchability = none  
 Expiration Date = 7/1/2004

<u>Year</u>	<u>Month</u>	<u>Generation - MWh</u>	<u>Year</u>	<u>Month</u>	<u>Generation - MWh</u>
1995	Jan	9,860	1998	Jan	6,090
	Feb	8,391		Feb	9,035
	Mar	8,565		Mar	9,495
	Apr	10,280		Apr	9,867
	May	10,371		May	9,908
	Jun	7,801		Jun	8,178
	Jul	3,803		Jul	3,527
	Aug	2,449		Aug	1,423
	Sep	2,498		Sep	2,178
	Oct	5,004		Oct	3,678
	Nov	8,342		Nov	4,232
	Dec	7,645		Dec	8,602
1996	Jan	10,915	1999	Jan	10,724
	Feb	6,138		Feb	8,703
	Mar	9,755		Mar	10,238
	Apr	8,498		Apr	9,255
	May	8,159		May	8,349
	Jun	9,199		Jun	8,383
	Jul	3,945		Jul	6,266
	Aug	1,757		Aug	2,520
	Sep	2,727		Sep	2,417
	Oct	3,656		Oct	3,467
	Nov	4,955		Nov	4,844
	Dec	8,307		Dec	9,988
1997	Jan	9,902			
	Feb	10,019			
	Mar	9,721			
	Apr	7,634			
	May	3,825			
	Jun	6,995			
	Jul	7,819			
	Aug	2,667			
	Sep	3,072			
	Oct	5,067			
	Nov	5,704			
	Dec	7,560			

Table G-16

PURPA Thermal Plants

Minnesota Methane/MM Spokane Energy LLL

Rated Capacity = 900 kW  
 Hours Connected to System = Not Available  
 Level of Dispatchability = none  
 Expiration Date = 4/03/2016

<u>Year</u>	<u>Month</u>	<u>Generation - MWh</u>	
1998	Jan	0	
	Feb	0	
	Mar	0	
	Apr	0	
	May	0	Purchased the output 5/25/98
	Jun	228	
	Jul	454	
	Aug	417	
	Sep	420	
	Oct	417	
	Nov	529	
	Dec	496	
1999	Jan	379	
	Feb	256	
	Mar	418	
	Apr	411	
	May	515	
	Jun	433	
	Jul	482	
	Aug	456	
	Sep	472	
	Oct	473	
	Nov	457	
	Dec	473	

Table G-17

**PURPA Hydroelectric Plants**

**Meyers Falls/ HydroTechnology Systems**

Rated Capacity = 1300 kW

Hours Connected to System = Not Available

Level of Dispatchability = none

Expiration Date = 12/31/2006

<u>Year</u>	<u>Month</u>	<u>Generation - MWh</u>	
1999	Jan	0	
	Feb	0	
	Mar	439	
	Apr	829	
	May	825	Sold the plant 2/12/99
	Jun	871	
	Jul	834	
	Aug	877	
	Sep	826	
	Oct	757	
	Nov	819	
	Dec	877	

Scheduled energy not metered energy

## Economy Purchases and Sales

**Table G-18**

<u>Year</u>	<u>Month</u>	<u>Total Short-term Sales - MWh</u>	<u>Average Cost Mills/kWh</u>	<u>Total Short-term Purchases - MWh</u>	<u>Average Cost Mills/kWh</u>
1995	Jan	64,792	18.20	156,753	14.60
	Feb	100,739	12.10	90,075	10.70
	Mar	73,745	12.70	170,578	11.10
	Apr	44,842	12.60	147,880	12.00
	May	63,761	9.60	130,030	9.40
	Jun	222,951	5.50	115,289	9.70
	Jul	146,089	10.80	154,864	12.60
	Aug	137,075	15.20	169,536	16.90
	Sep	202,050	16.20	216,556	16.50
	Oct	248,201	14.70	316,343	11.80
	Nov	266,197	14.50	338,703	11.60
	Dec	386,710	12.50	438,626	9.20
1996	Jan	454,848	14.10	506,752	10.80
	Feb	393,833	13.00	366,217	10.10
	Mar	472,178	11.60	444,631	8.10
	Apr	465,784	9.80	406,995	8.30
	May	505,355	9.80	449,308	8.10
	Jun	694,408	9.36	664,722	9.00
	Jul	903,221	11.20	1,024,820	10.20
	Aug	616,967	14.70	768,015	13.50
	Sep	715,523	15.00	811,316	14.30
	Oct	597,694	16.00	795,513	15.60
	Nov	681,831	18.50	1,187,814	20.10
	Dec	875,158	19.60	1,496,247	20.30
1997	Jan	785,455	15.34	957,485	15.68
	Feb	766,226	14.33	937,534	12.72
	Mar	957,637	11.44	994,721	10.72
	Apr	829,468	11.50	828,168	10.48
	May	1,053,496	11.18	937,016	11.73
	Jun	1,289,979	11.94	1,226,763	12.46
	Jul	1,560,227	15.41	1,427,275	15.80
	Aug	1,103,824	18.02	1,199,566	17.54
	Sep	949,004	21.15	1,132,663	19.64
	Oct	965,159	18.37	812,509	17.86
	Nov	931,711	21.25	933,751	20.04
	Dec	910,810	20.84	894,638	19.98



## Economy Purchases and Sales (continued)

1998	Jan	883,456	19.57	914,422	20.60
	Feb	979,108	17.13	1,068,522	17.48
	Mar	1,185,458	16.69	1,224,978	15.59
	Apr	1,394,605	17.13	1,356,928	16.50
	May	1,137,592	14.08	975,395	13.91
	Jun	1,367,472	14.56	1,211,155	14.77
	Jul	1,521,454	22.45	1,418,320	22.50
	Aug	1,542,756	30.23	1,560,756	30.51
	Sep	2,134,907	31.05	2,158,504	32.85
	Oct	941,013	26.57	962,296	27.05
	Nov	1,165,315	27.78	1,122,001	27.53
	Dec	1,284,335	27.92	1,336,667	28.90
1999	Jan	1,286,835	22.39	1,428,764	24.91
	Feb	933,631	19.78	1,031,218	21.76
	Mar	690,097	20.01	841,704	20.99
	Apr	800,384	19.62	768,516	19.37
	May	1,203,987	19.83	1,090,078	20.24
	Jun	1,191,973	18.66	1,108,388	19.90
	Jul	1,668,614	27.62	1,688,631	29.65
	Aug	1,527,405	33.82	1,604,909	34.11
	Sep	1,689,791	33.41	1,685,617	34.07
	Oct	1,050,743	37.68	1,007,130	36.12
	Nov	1,024,158	30.25	865,599	32.17
	Dec	1,372,407	28.81	1,219,047	29.34



APPENDIX H

OTHER ITEMS

## **DISTRIBUTION SYSTEM AND PRACTICES**

### **Scope of the Distribution system**

The Distribution system starts at the substation fence and ends at the customer's meter. Between these two points, distribution feeders consisting of poles, conductor, transformers and associated devices provide the interface between the substation and the customer. An equivalent underground system exists as well. At Avista Utilities, the primary voltage levels range from 34,500 volts to 2,300 volts.

### **Distribution Planning**

Distribution feeders are designed, built and upgraded based on Reliability and Planning criterion. Planning is the task of identifying when new substations and distribution feeders are to be built or when the current carrying capability of the conductors need to be increased. Planning can also be called Distribution Load Forecasting. A long range plan is prepared through the use of a load-forecasting program. Ten-year distribution forecasts are performed for both summer and winter peak loads. Avista uses a PC based program to forecast loads. The program uses five years of load history along with a growth rate to predict what future loads will be. The analysis then flags capacity problems on substation transformers and feeders based upon loading criteria specific to urban and rural areas. There are two main components used in the load-forecasting program: capacity data and load data. Capacity data is gathered annually by studying substation and distribution equipment load data. Feeder load readings are examined monthly. At the completion of a Distribution Load Forecast, the distribution system upgrades for the next ten years will have been identified.

Reliability criterion insures that the Avista Utility distribution system is operated to assure continuity of service consistent with sound economical planning principles. The intent is to limit the number of customers affected by an outage and the duration of the outage. National and state standards are used to establish normal and emergency levels for customer voltage, distribution equipment loading and distribution short circuit levels.

### **Distribution Construction Budget**

The Distribution Construction Budget consists of:

Growth items driven by a load growth forecast. This includes all projects providing additional capacity to serve projected future load.

Maintenance items submitted by operating areas. These are primarily increasing the current carrying capacity of the feeders.

## **Distribution Practices**

Substation site selection, loss reduction and asset management are items under this topic.

The selection of a substation is an economical analysis including cost of present and future system losses, cost of additional transmission and cost of land. Surrounding geography and availability of suitable land factor into the selection. Transmission routing has a major impact on the selection process and can be the overriding consideration.

Distribution loss reduction is an attempt to run the system as efficiently as possible.

In the early eighties, Avista started using economic conductor analysis for all new construction. Economic conductor sizing includes the cost of distribution conductor losses when selecting the conductor size.

About the same time, a system-wide capacitor replacement program was initiated. This was an opportunity to optimize the number and location of capacitors for line loss reduction. When distribution feeders are modified, capacitor banks are reviewed for proper location and size.

When transformers are purchased, the associated core and winding losses are evaluated as part of the bid. The total ownership cost of the transformer, (purchase price and losses over the life of the transformer) is examined.

The distribution feeders are reviewed for load imbalance. Reducing load imbalance is a cost-effective means of lowering system losses.

Avista has been converting older 2,300 and 4,000 volt distribution systems to higher operating voltages and in doing so, the feeder amps and corresponding losses are decreased. There are two of these systems to be converted.

Asset management is a process to control costs.

Through a comprehensive integrated set of Material, Design and Construction standards, uniform construction practices are attempted. This is an attempt to avoid the acquisition of non-standard items. When purchasing materials for line construction, the lowest purchase price does not necessarily mean the least installed-cost; the big picture must be kept in view.

Avista has an active pole inspection, stubbing and replacement program. Through programs such as this, the useful life of the installed plant is extended. Prior to any distribution rebuild or voltage conversion, an inspection is completed to assess the condition of the poles.

Avista utilizes computer modeling extensively.

The distribution system is modeled for voltage, overloaded equipment, short circuit current and voltage flicker. These models will predict the improvements that can be achieved when a feeder is reconfigured or upgraded. The software, which is used to build the models, was purchased from an external vendor.

The implementation of GIS (graphical information system) is underway. In addition to a mapping system, this tool allows access to the distribution system data-base for data acquisition, system analysis and design.

To gain more experience in the area of Distributed Generation, a Micro-turbine has been placed on the Avista system and operational data is being acquired. In addition, a Fuel Cell has been in operation for several years and operational experience is being accumulated with it. Computer modeling is being conducted to determine the affects of Distributed Generation on the Distribution system.

### **Conclusion**

Avista is actively engaged in exploring cost effective and efficient ways to distribute energy to our electrical customers. New products are being tried to make our distribution systems more efficient with out sacrificing safety.

## SYSTEM PLANNING (TRANSMISSION)

### **Relationship to Resource Planning**

Avista (Transmission) System Planning and Operations continues to respond to the requests from Resource Planning for integration of resources to serve retail load. As Resource Planning analysis installation of additional generation on the system, it will make requests for studies from System Planning. System Planning will investigate the impacts and provide information as requested to Resource Planning for use in evaluation of the cost-effectiveness of various resource options. System Planning's goal is to provide reliability and maximize the efficient use of the transmission system.

### **Current Issues**

Avista System Planning and Transmission Operations faces an uncertain future as a result of the current restructuring of the Electric Transmission Businesses as the industry moves toward a more deregulated market. This turmoil includes several activities:

- 1. An increased emphasis on reliability.** Both the North American Electric Reliability Council (NERC) and the Western Systems Coordination Council (WSCC) have instigated a move toward mandatory compliance with reliability and operating criteria.
- 2. An increased emphasis on operational studies** to determine the simultaneous capability of transfer paths. This has resulted in the formation of four regional study groups that determine simultaneous and non-simultaneous capabilities of all impacted transfer paths. Included in this is the Northwest Operational Planning Study Group in which Avista participates. The rule for operation states simply: if the flow pattern hasn't been studied to assure system integrity, then the system cannot be operated in that way.
- 3. A move toward consolidation of transmission resources into larger organization** so that it will be more completely separate from any merchant entities. On December 20, 1999 the Federal Energy Regulatory Commission (FERC) issued its final rule (**Order No. 2000**) regarding the **development of Regional Transmission Organizations (RTOs)**. The Order requires that all public utilities that own, operate or control interstate transmission facilities file by October 15, 2000, either a proposal to participate in an RTO or an alternative filing describing efforts and plans to participate in an RTO. Avista with other utilities filed a phase one RTO West.

The big impact of #1 above is that previous to this move toward mandatory compliance, utilities could occasionally violate WSCC reliability criteria (usually unintentional) as long as there were no detrimental effects on neighboring systems. Mandatory Compliance states that utilities must now meet all criteria within their own boundaries as well as not affecting others. On June 18, 1999 the majority of the members of the WSCC signed agreements to participate in the WSCC's Reliability Management System (RMS). This system tracks violations of operating and planning criteria with consequences ranging from letters to management and State Utility Commissions to monetary penalties. The initial RMS implementation included only critical operating criteria. A pilot NERC

compliance program is under way that will eventually blend with RMS. Ultimately there will be a complete Mandatory Compliance system that will require utilities to get a long list of important operating and planning criteria. The consequences for non-compliance may be severe and include monetary penalties. The full implementation of Mandatory Compliance will require national legislation to be effective and binding.

The **increased emphasis on operational studies** is a result of de-regulation and other factors that put the transmission system of the Western Interconnection at a potentially higher operational risk. The two large widespread outages in 1996 contributed to the urgency of making sure the transmission system can handle transfer needs in each upcoming operating season. Abnormally large amounts of new generation are planned for installation in the Western Interconnection in the next 3-5 years. While local interconnection studies are being performed, it is nearly impossible to do long range system wide planning because no one knows what new plants will come to fruition and what the actual generation patterns will be. Other factors, such as changes in generation patterns on the Columbia river to help mitigate fish depletion have added complexity to planning studies. As a result of all of this, more emphasis is being put on the near term "operational" studies rather than longer term "planning" studies. Each sub-region will analyze the allowable transfer levels for recognized transfer paths. Avista is an active participant in the Northwest Operational Planning Study Group.

Order No. 2000 requires Avista and other interstate transmission owners to work together to determine possible configurations for a Regional Transmission Organization (RTO), and to file a plan with the FERC on or before October 15, 2000. Avista and other transmission owners have proposed formation of an Independent Transmission Company (ITC), and will file for its formation with the FERC by this deadline. Work on the RTO and ITC proposals have been a monumental task because of differences in transmission rates between the differing utilities, and the fact that the FERC would like whatever transmission organization ultimately forms (whether just the ITC or a combination of an ITC with an RTO) to levelize the cost of transmission to encourage open access. Implementation of an ITC or RTO could cause cost shifts for the participants that are beneficial to some and unacceptable to others. Avista expects the discussions surrounding and ITC and/or RTO to continue to develop over the next year to eighteen months.

**Expansion Possibilities & System Reconfiguration**

The impact of expansion on the Avista transmission system is largely dependent upon the location of the proposed expansion. Some of the possible solutions to various system constraints may have the added benefit of making load and generation additions more easy to integrate. These solutions include possible conversions of parts of the 115 kV system to a radial rather than looped system and a significant amount of additional or reconductored 230 kV transmission lines. Any new load or generation integration will continue to be handled on a case by case basis.

**Reliability**

Avista's transmission system is planned, designed, constructed and operated to meet peak load demands and peak load transfers while assuring continuity of service during system disturbances and to be consistent with sound economic planning principles. FERC Form 715 includes the planning limits of both the transmission lines and transformer capabilities for the Avista system. Avista Planning uses the Western Systems Coordinating Council's "Reliability Criteria for System Design" as a benchmark to determine the performance of Avista's system in relation to interconnections with other Northwest regions and utilities.

**PUBLIC INVOLVEMENT**

Avista serves at the consent of its publics. The company believes the most effective way to reach balanced business decisions is by working with the public, utility commission staffs and other key audiences. An effective public involvement process creates the opportunity to build credibility and trust for the company. Avista realizes public participation will continue to be an important consideration in resource planning as well as all other business decisions.

Public meetings, open houses, facility tours, customer surveys and advisory groups are all being used today to help others understand the company's situation, receive input from constituency groups, gauge public concerns and accommodate group needs. Avista is firmly committed to the education of all its stakeholders. Communication, education and involvement are the foundation of Avista's internal and external relations.

There are dozens of utility company projects going on each day through out the service territory. Most of this work is low-impact, routine maintenance completed on existing facilities. Occasionally a more significant project with noticeable effects is required in order for the company to continue to provide safe and reliable service.

It is these more complex projects with more community impact that an exchange of information between all parties is essential. Avista uses public meetings to educate the public about the need for the project and to solicit input and, when possible, obtain consensus on the preferred alternatives from the standpoint of impacts to the communities affected. Avista holds public meetings on an issue-specific basis throughout the year. Meetings are formatted to allow citizens to take in valuable information as well as ask questions of accountable Avista employees and provide input on preferred alternatives or community impacts that need to be taken into account.

A good example of this public involvement was the company's huge effort in getting the relicensing completed for the Noxon Rapids and Cabinet Gorge hydro facilities. This public involvement resulted in a comprehensive settlement agreement with 27 parties. The company utilized a unique collaborative approach that produced one of the most successful ever-hydro relicensing efforts.

Technical Advisory Committee (TAC):



The TAC is comprised of representatives from customer groups, government agencies and environmental organizations, which reviews all of Avista's resource planning activities. Avista sponsored three TAC meetings during this latest planning cycle. The three dates and information discussed were:

- August 19, 1999
  - IRP Plan and Future Activities
  - Energy (electric and natural gas) Forecast
  - Fuel Cells
  - Energy Efficiency Programs
  
- November 18, 1999
  - Future Gas Supply and Prices
  - Wholesale Markets and Prices
  - Relicensing of Noxon and Cabinet
  - Distribution Planning
  - Bull Trout Impact on System Hydro
  - Transmission Planning
  - Centralia Sale
  - Level of Risk in Marketing Activities
  - Identification of Stranded Costs
  
- June 22, 2000
  - Need for Additional Resources
  - Resource Analysis
  - Avista's Models and Model Outputs
  - Forward Pricing Curves (electric and gas)
  - RFP Purpose and Status
  - New Resource Site Investigation
  - IRP Partial Draft

#### Survey Results:

The company handed out a survey at the last TAC meeting to try and get feed back from the participants as to the effectiveness of the meetings and their needs. The six questions and a summary of responses received are:

1. Are we providing enough information to meet your needs?  
Answers- Yes (at this time), might help to have pre-meeting information.
2. What about the quality (verbal and written) of the information?  
Answers- Great.
3. How can we improve the feed back from you to us?  
Answers- Ask for it, more contact outside the scheduled meetings.
4. Is the number of TAC meetings okay?  
Answers- Yes.
5. If there were additional information you need, what would it be?  
Answers- None, information ahead of time, comparison of resource alternatives.

6. Do the presenters at the meetings provide enough information?

Answers- Yes.

### **HYDRO PROJECT RELICENSING**

Avista Corp. was granted by the Federal Energy Regulatory Commission on February 23, 2000, a new 45-year license to operate the Noxon Rapids and Cabinet Gorge hydroelectric projects on the lower Clark Fork River. The license order was received a year before the existing licenses expired and culminates seven years of planning and consultation, utilizing a unique collaborative approach that produced one of the most successful ever hydro relicensing efforts. The application to relicense was submitted by Avista Corp., February 18, 1999, and contained a comprehensive settlement agreement with 27 signatories.

**Avista was  
granted a  
new 45-year  
license for  
Noxon  
Rapids and  
Cabinet  
Gorge**

The landmark agreement ensured the continued economical operation of the two plants while providing a variety of enhancements to natural resources of the project area. Avista Corp. retains nearly all the valuable load following and peaking capability of the two projects while providing early implementation of protection, mitigation, and enhancement measures to benefit native fish species, recreation opportunities, continued protection of cultural resources, wildlife populations, and water quality. Avista Corp. will spend approximately \$4.7 million annually with a significant expenditure earmarked for enhancing bull trout populations. Bull trout are presently listed as threatened under the Endangered Species Act.

The highly successful outcome of the relicensing process has received national media attention and awards. Avista Corp. received in 1999 the National Hydropower Association's prestigious Hydro Achievement Award for Stewardship of Water Resources. The award was given to Avista Corp. for exemplary stewardship of the nation's rivers, resourcefulness, and creativity in meeting challenges associated with hydroelectric development; and an uncompromising commitment to championing hydro power as a vital component of the country's energy future.

The FERC license order and settlement agreement is in many ways the first of its kind, and represents a cost to the company well below the outcomes of other hydro relicensing proceedings where issues were often contested. The following summarizes the highlights of the Clark Fork hydro relicensing program:

- At nearly 800 MW of generating capacity, this is the largest collaborative relicensing effort ever undertaken in the United States.
- The Clark Fork process is considered the template for FERC's new collaborative alternative relicensing approach and is the first-ever on time relicensing for a major project.

- The Clark Fork Settlement Agreement comprises 27 participants and is the first of its kind in the nation for a large project. Signatories include Native American Tribes (5), federal agencies (2), state agencies (8), nongovernmental organizations (10), and local authorities (2).
- A partnership with Trout Unlimited represents a first of its kind with a national river organization.
- The Living License™, created in the Avista Corp. process is a first of its kind. Based on the principles of adaptive management and flexible funding, this innovative approach has created among the participants unprecedented local ownership and joint management of new license conditions.
- Precedent setting acceleration of Noxon Rapids license term by four years (2005 to 2001 to coincide with Cabinet Gorge license) facilitates simultaneous relicensing of both projects.
- Other precedents in the relicensing process include early FERC involvement, early EIS scoping, and neutral facilitation of consultation process.
- The first Programmatic Agreement for a project of this size, signed by five tribes, two states, and the federal government that resolves cultural resource issues.
- Successfully incorporated agency mandatory conditioning authorities with local, consensus-based, decision making.
- The first collaboratively prepared environmental assessment and license application for a large project.
- First relicensing process resulting in early implementation (two years prior to license expiration) of new license terms and funding of natural resource protection and enhancement measures.

## AVOIDED COST

Avoided costs are costs determined by a public utility commission process that is intended to represent the costs a utility would otherwise incur to generate or purchase power if not acquired from another source. These costs would apply to customer owned resources made available to Avista.

In general, avoided cost is meant to represent the incremental cost of new electric resources available to a utility. Avoided cost rates reflect the price of power from avoided resource or resource mix. These rates are often applied to the purchase of energy from PURPA qualifying facilities (QF). In some cases, the avoided cost is used to determine the cost-effectiveness of potential resource alternatives.

Presently, the avoided cost methodology used in the filed tariff for the purchase of QF's output of less than one megawatt in size is the same in both Washington and Idaho. The avoided costs are based on a gas-fired combined cycle combustion turbine, used as the surrogate firm resource to determine costs of future power during the projected time period of resource need. Based on the 2000 RFP, Avista has good data on the capital and siting costs of a CCCT. The big question in these calculations is the future cost of natural gas. Gas price assumptions can vary the project economics substantially. The company has, from third parties, scenarios of natural gas prices into the future. Avista will use all of this information to derive the avoided cost figures which will be representative of the costs that the company might expect associated with the construction and operation of a CCCT.

The avoided costs shown in the 2000 RFP are based on figures from the NWPPC and natural gas prices from the company's natural gas 2000 IRP. Based on the current situation these gas prices are probably on the low side. These inputs resulted in the calculated avoided cost in the RFP to rise from \$38 per MWh in 2004 to \$58 in 2020.

With the publication of the 2001 IRP, Avista will file revised avoided costs to match the parameters in the IRP, including information received from the 2000 RFP. Avista has 90 days after the IRP filing to file revised numbers in Washington. The company will also file at about the same time updated avoided cost numbers in Idaho. This will allow the company to remain in compliance with the state's requirements in their management of the PURPA legislation.



## APPENDIX I

# GLOSSARY OF TERMS, ABBREVIATIONS & ACRONYMS

Aggregators	Brokers who seek to bring together customers or generators to buy or sell power in bulk, making a profit on the sale.
Average Megawatt (aMW)	A measure of the average rate of energy delivered. One aMW equals 8,760,000 kWh per year.
Avista Corp.	Formerly the Washington Water Power Company and the parent company for Avista Utilities.
Avoided Costs	Costs determined by a public utility commission process that are intended to represent the cost a utility would otherwise incur to generate or purchase power if not acquired from another source.
B. C. Hydro	British Columbia Hydro and Power Authority.
Base Loaded	A resource which operates more efficiently without being cycled to meet daily load changes.
Bilateral Contracts	Contract between a generator and consumer which may involve aggregation.
BPA	Bonneville Power Administration, the federal power marketing agency for the Pacific Northwest.
Capacity	The maximum load a generator, power plant, or power system can produce or carry under specified conditions.
Capacity Constrained	A condition where a system adds resources for capacity needs rather than energy needs.
Capitol Costs	Cost of investment in a new resource, installed \$ per kW.
CF (Capacity Factor)	The percentage of a resource's maximum generation capacity that is actually used.
Cogeneration	The sequential production of electricity and useful thermal energy.
CO2 (Carbon Dioxide)	An emission from fossil fuel burning.
Competition Transition Charge (CTC)	Nonbypassable charge to customers to recover utility stranded costs.
Conservation	Reducing electrical consumption with measures that increase the energy efficiency of appliances, motors, building shells, etc.

Cost Shifting	Shifting cost from one group of customers to another—from industrial to residential or commercial to residential—or from one utility to another.
CPUC	California Public Utilities Commission.
Critical Period	The historical period of water conditions during which the region's hydro power system would generate the least amount of energy while drafting shortage reservoirs from full to empty.
Customer Groups	Industrial, residential, commercial and agricultural.
Data Resources Inc. (DRI)	WWP's national economic forecasting contractor.
Demand	The instantaneous rate at which electric energy is delivered to or used by a system.
Demand-Side Management (DSM)	The activity of acquiring demand-side resources.
Demand-Side Resources	Resources that can be added to a utility system to reduce customer electric usage, or control the timing or shaping of such usage.
DIG	Demand Side Issues Group
Direct Access	Ability of a power producer to sell directly to a retail customer.
Dispatchability	The ability to operate or not operate a resource for economic reasons.
Distribution	Function of distributing power to retail customers.
Distributed Generation	Generation, storage or DSM devices, measures and/or technologies that are connected to or injected into the distribution level of the power delivery grid.
DSI	Direct Service Industries (certain industrial customers of BPA)
Electrical Energy	The amount of electrical usage or output average over a specified period, e.g. kWh.
Energy Policy Act (EPAcT)	House Referendum #776 passed in 1992, encouraged competition among bulk power producers.
EMF	Invisible lines of electric and magnetic fields surrounding an electric conductor, commonly

	referred to as Electro-Magnetic Fields.
End-Use	The final use of electricity by customers (e.g. lighting, cooking, etc.).
Environmental Externalities	Environmental effects, including environmental benefits, that are not directly reflected in the cost of electricity.
EWG	Exempt Wholesale Generator (of electricity). They are exempt from certain regulations which traditional utilities must follow.
Existing Resources	Those resources that are currently in use, or being developed under contract but not yet in operation.
FERC	Federal Energy Regulatory Commission.
Firm Load	Customer load served by a utility without a contractual provision for curtailment.
Fixed Costs	Costs that do not vary in relation to change in plant output.
Fossil Fuels	Coal, oil, natural gas and other fuels deriving from fossilized geologic deposits.
Framework	CPUC's new market structure for generation, transmission and distribution among investor-owned utilities.
Fuel Cells	Fuel cells convert hydrogen gas to electricity through an electrochemical process with no combustion.
Fuel Efficiency	Utilizing fuels in applications that produce the greatest end-use efficiency (e.g. conversion of electric space and water heating to natural gas).
Fuel Mix	The make-up of resources used to serve load by fuel type.
Generation	Producing electricity.
Generation Costs	Costs associated with producing electricity or acquiring it through contracts.
Grid	Large electric system linking transmission lines both regionally and locally.
GWh	1 gigawatt-hour = 1 million kilowatt hours.
Independent System Operator (ISO)	Independent operator of transmission lines to assure reliable and fair transfers of electricity from generators to distribution companies.



Inland Northwest	The area of eastern Washington, northern Idaho and western Montana.
Integrated Utility	Utility that provides generation, transmission and distribution services for its customers.
IOU	Investor-Owned Utility.
IPP's	Independent Power Producers.
IPUC	Idaho Public Utilities Commission.
IRP	Integrated Resource Plan or integrated resource planning.
kW	1 kilowatt = 1000 watts
kWh	1 kilowatt-hour = 1000 watt-hours
Levelized Cost	The present value of a cost stream converted into a stream of equal annual payments.
Load	Amount of electricity being used at any given time.
Load Forecast	The predicted demand for electric power for planning purposes.
Lost Opportunities	Resources, which if not acquired or developed within a certain time, could be lost.
Market Forces	Competition for sales, new alliances, innovative pricing structures, customer demand, choice and various kinds of services.
Market Power	Domination of the new marketplace by electricity suppliers that own a high percentage of generation.
MCS	Model Conservation Standards.
Mill/kWh	One mill equals one tenth of a cent. Frequently used as a monetary measure when referring to the cost of producing or conserving electricity.
Monte Carlo Simulation	Monte Carlo refers to the traditional method of sampling random variables in simulation modeling. Samples are chosen randomly across the range of the distribution.
Muni	Municipal- or publicly owned utility.
MW	1 megawatt = 1000 kilowatts

MWh	1 megawatt-hour = 1000 kilowatt-hours
Net System Load	The total load of a system, including both firm and interruptible, within a utilities service area.
Nominal	Rates or costs that include the effects of inflation.
Nonfirm Interruptible Load	Load which can be curtailed in response to a system emergency.
Nonfirm/Secondary Energy	Electric energy having limited or no assured availability.
Nonutility Generation	Generation by producers other than electric utilities.
NWPP	Northwest Power Pool, an organization of electrical utilities.
NWPPC	Northwest Power Planning Council. A federally chartered council comprising Idaho, Oregon, Montana and Washington that establishes policy on Northwest electrical energy, fish and wildlife issues.
O & M	Operation and Maintenance Costs.
Obligation to Serve	Regulatory obligation of a utility to provide electric planning services for all customers and to assure an adequate supply of electricity now and in the future.
Pacific Northwest Coordination Agreement (PNCA)	An agreement signed in 1964 by the federal government and Northwest utilities to agree to operate generating projects as a single entity to make the optimum use of the water and storage resources in the region.
Peak	The greatest amount of demand occurring during a specific period of time.
Performance-Based Ratemaking (PBR)	Regulated rates based on performance objectives, not on actual costs.
Power Brokers and Marketers	Companies seeking to sell generation to large industrial customers or to an aggregate of smaller customers.
Power Exchange (PX)	"Spot" price market where electricity is bought and sold much like a stock exchange.
Present Value	The worth of future returns of costs in terms of their value now.
PUHCA	Public Utilities Holding Company Act.

PURPA	Public Utility Regulatory Policies Act.
QFs	Qualifying Facilities under PURPA (cogeneration and small power production facilities).
Rate Regulation	Supervision over rates and major decisions by elected officials and their appointees.
Real	Costs or rates that are corrected for the effects of inflation.
Redesign or Reengineering	Process corporations utilize to eliminate non-value added work and handoffs.
Regional Transmission Group (RTG)	New forum for energy service providers within a specific geographic area to agree on operating parameters and resolve issues.
Regulatory Compact	Long-term agreements between regulatory agencies and utilities, which are usually embodied in regulatory decisions.
Reliability	A measurement of the availability over a defined period regarding the delivery of power to a customer.
Renewable Resource	Resources such as wind, solar, hydro, etc., in which their availability is not limited by use.
Resource Clearinghouse	WWP's internal employee group responsible for overall integration of resource acquisition activities.
Restructuring	Reconfiguring the market structure by opening the generation of electricity and retail services to competition.
Retail Wheeling	An alternative to traditional energy service where customers are able to choose any electric provider they want.
Seasonal Output	Electrical output from a resource which varies in amount according to the season.
Stranded Costs	Costs associated with providing electricity that are above market prices.
Supply-Side Resources	Resources that generate an electrical output in the utility system.
TAC	Technical Advisory Committee.
Tariff	A schedule filed by a utility with a regulatory agency describing transactions between the utility and customers in terms of type of service,

	rates changed and means of payment.
Tariff Rider	A separate Schedule of rates, in addition to general tariff, intended to collect payment for specific programs or services such as DSM.
Traditional Ratemaking	Regulated rates based on costs expanded, not on meeting performance objectives.
Transition Period for Direct Access	1998-2005, as defined by the CPUC.
Transmission	Lines over which electricity from generators is sent to distribution companies.
Transmission Availability	A separate schedule of rates, in addition to general tariff, intended to collect payment for specific programs or services such as DSM.
Unbundled Rates	Separate line-item charges for generation, transmission, distribution and other services and programs.
Unbundled Services	Functional separation of generation, transmission and distribution services. Customers can select generation services from competing suppliers (direct access).
Utility Distribution Company (UDC)	The regulated utility that serves as the intermediary between the generator and the consumer by supplying distribution services.
Variable Costs	Costs that vary in direct proportion with plant output.
Watt	A basic unit of electric power equal to 0.00134 horsepower.
Weatherization	A process of making buildings more energy efficient such as the Home Insulation Program.
Wheeling	The use of one utility system's transmission facilities to transmit power of and for another system.
Wholesale Wheeling	Selling electricity to wholesale buyers to resell to retail customers.
WNP	Washington Public Power Supply System Nuclear Project.
WSCC	Western System Coordinating Council.
WUTC	Washington Utilities and Transportation Commission.



## APPENDIX J

# AVISTA'S ENERGY EFFICIENCY RESOURCES



## AVISTA CORPORATION ENERGY EFFICIENCY RESOURCES

### Summary

Avista Corporation has been operating demand-side management (DSM) programs, in one form or another, for over ten years. These programs are funded by the Energy Efficiency Tariff Rider, a surcharge on Washington and Idaho retail electric rates, that has been in place for over five years. Current DSM activities are conducted by the Energy Services Department funded by the Tariff Rider at a level of 1.0% in Idaho and 1.5% in Washington.

### History

- |           |   |
|-----------|---|
| Pre-1990  | Energy efficiency activities conducted by Avista was limited to small scale capitalized programs.   |
| 1991      | Avista introduced the first significant non-residential energy efficiency programs.   |
| 1992      | Avista introduced the first significant residential energy efficiency programs. Included was a pilot for the Switch-Saver program, which funded conversions of residential space heating and domestic hot water from Avista electric to natural gas.  |
| 1993-1994 | Based on the success of the Switch-Saver program, Energy Exchanger was Initiated, which funded fuel conversions for all Avista Utilities residential electric customers.  |
| 1995      | The Washington Utilities and Transportation Commission (WUTC) and Idaho Public Commission (IPUC) approved the implementation of North America's first non-bypassable distribution charge to fund the conservation activities of Avista Corporation. Called the DSM, or Energy Efficiency, Tariff Rider, it was funded by electric and natural gas surcharges (1.5% and 0.5% respectively) and administered on a two year pilot basis. |
| 1996      | The Tariff Rider was extended for the three-year period through 1999. The natural gas surcharge was adjusted to 0.0% as a result of the substantial reduction in the cost of natural gas. The stipulation was made that the natural gas surcharge would be reestablished at a level above 0% if gas efficiency programs could be cost-effectively offered to a broad customer base.   |
| 1998      | The fixed sunset date for Tariff Rider funding was lifted. The only remaining condition for termination is based upon the imposition of public purpose legislation in Washington and Idaho.   |
| 1999      | The WUTC and IPUC approved revision to the Tariff Rider, allowing DSM program administration to be aligned more closely with customer needs.  |
| 1999      | The Idaho general ratecase filed by Avista Corporation resulted in the reduction of funding through the electric surcharge collected in Idaho from 1.5% to 1.0%   |

## **The Tariff Rider**

The Tariff Rider has funded the energy efficiency activities of Avista in Washington and Idaho since 1995. In 1998 the sunset date for funding of the Tariff Rider was lifted, allowing us to administer DSM without the looming prospect of funding termination.

Recently, the Idaho general ratecase filed by Avista Corporation resulted in the reduction of funding to the Tariff Rider in Idaho from 1.5% to 1.0%. This was mandated as a result of a persistently positive Tariff Rider balance within Idaho.

The purpose of the Tariff Rider is to allow continued energy efficiency funding irrespective of increased competition in the electric industry. By shifting revenue collection from generation to distribution, several problems with historical energy efficiency accounting are alleviated. The Tariff Rider provides a stable, predictable source of conservation funding while eliminating concerns about capital budgeting, accumulation of increased regulatory assets, uncertain future regulatory treatment of capitalized investment, and future competitiveness.

The Tariff Rider mechanism maintains continuity in the promotion and support of energy efficiency, provides for long-term resource diversity, recognizes the timing of resource needs, promotes the transformation of consumer markets to energy efficient choices, and provides a valuable customer service.

Avista Corporation's Tariff Rider currently collects approximately \$4.5 million per year.

## **Local and Regional Benefits**

In 1999 Avista fundamentally altered the approach to DSM from a regulatorily inspired traditional utility program approach to a market segmentation approach. The market segmentation approach focuses on customer needs of segments (i.e. retail, office, etc.) rather than on rate schedules and similar regulatory distinctions. Avista expects this approach to allow the company to be more responsive to customer need.

In recognition of the unique needs of the limited income and physically challenged customers, Avista has established this as its own customer segment within the strategy. The focus of this segment has been electric to natural gas conversions, enhancing energy efficiency measure persistence by treating the health and human safety issues for the structure and the implementation of assistive technologies to improve the safety and quality of life for the physically challenged customers.

In addition to ten customer segments, Avista has also identified fifteen technologies that are individually managed to ensure that Avista is at the forefront of the industry in knowledge. The technology managers have the resources and knowledge to assess the applicability of their technology and work with individual customer segment managers to bring it to the customer site.





energy efficiency measures. This is part of an effort to not only more accurately assess the cost-effectiveness of the programs, but also to identify non-energy benefits that are of value in marketing the programs. Organizationally, the cost-effectiveness data is through the end of calendar year 1998. An evaluation of cost-effectiveness for calendar year 1999 is currently underway.

It is also worth noting that Avista periodically reviews the potential for providing natural gas efficiency services to our retail natural gas customers. The initial Tariff Rider and program filing in 1995 included a natural gas surcharge of approximately 0.5% and corresponding program offerings. The natural gas surcharge was reduced to 0.0% beginning in 1997 as a result of the lack of cost-effective program opportunities at the time of its approval.

Avista continually monitors the weighted average cost of gas (as a proxy for the gas avoided cost) and will reevaluate the cost-effectiveness of natural gas programs should it increase significantly. Avista will re-evaluate the potential for gas efficiency programs if changes in the weighted average cost of gas, gas end-use technologies, or methods of program delivery warrant the effort.

Since the implementation of the customer segment approach to delivering energy efficiency programs, Avista has committed to providing the Triple-E Board with trimesterly reports detailing significant projects, implementation changes M&E activities, and cost-effectiveness studies. The most recent report is included in this appendix.



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**Introduction**

This is the third Triple-E Report produced in fulfillment of Avista Corporation's commitment to enhanced analysis and reporting made at the time of the August 1999 Schedule 90 revision.

This report covers the four-month period from April 1, 2000 to July 31, 2000. Inasmuch as this is the third trimesterly report, we now have one full year of data produced using the same methodology. Consequently we have included as Appendix A several twelve-month summaries and graphs.

Except where noted, the methodology applied in developing these numbers is unchanged from that elaborated upon in previous Triple-E Reports. As a consequence you will find more numerical and less written content in this report.

Future Triple-E Reports may require significant modifications to incorporate the effects of the proposed natural gas efficiency portfolio, the implementation of proposals selected under the Avista Request for Proposals process and other changes as they become necessary.

## Quantitative Calculations

### Cost Allocation

Avista uses two approaches for compiling the costs attributable to energy-efficiency activities.

1. A cash basis is employed for use in determining utility expenditures for calculation of the Energy-Efficiency Tariff Rider balance. Both incentive and non-incentive utility expenditures are tracked in this way.
2. An accrual method is used for purposes of determining the utility incentive costs for calculation of cost-effectiveness. This accrual method realizes utility incentive costs for incomplete projects at the same rate at which energy savings from those incomplete projects are realized. For example, the methodology realizes 75% of the anticipated incentive cost when the project is contracted to match the 75% of the expected energy savings claimed upon contracting. This approach is intended to match the drop-out rate of projects as they progress through "the pipeline" as well as the utility resources invested in the project at each stage.

### Incentive Calculation, Capture of Analytical Data

The calculation of site-specific customer incentives was being centralized during this trimester, with the calculations performed by the Analysis Team. This change was made in order to ensure consistency in the calculation of incentives and to provide the opportunity for the Team to capture non-energy benefits and identify measurement and evaluation (M&E) opportunities.

A user-friendly incentive calculation model has been created to capture project-specific data. At the moment it is too early to determine if this will result in improved identification / quantification of non-energy benefits, but we are certain that this approach will virtually guarantee that all incentives are calculated in compliance with Schedule 90 and the policy manual that has been developed to guide implementation.

It is hoped that this calculation can be transitioned back to those responsible for program implementation once the model has proven itself and a sufficient body of precedence on policy issues has been compiled.

### Allocation of Utility Costs to Segments and Technologies

Whenever possible, utility non-incentive costs are directly assigned to the customer segments identified in this report. However, a sizable proportion of implementation activity covers multiple segments. These costs are allocated to either a general implementation or a general M&E account number.

At the close of the trimester the lead coordinator for Energy-Efficiency Tariff Rider opportunities allocates the general implementation costs to each individual segment. Similarly, the Analysis Team allocates general M&E costs to each individual customer segment.

Once these general costs have been allocated to customer segments, the customer segment managers allocate all costs assigned to their segment (both those assigned to that segment as well as those allocated from the general implementation account) to the various technologies.

The final result is an allocation of all utility non-incentive costs across the segment / technology matrix.

Incentive costs are all directly assigned to the segment/technology matrix based upon the nature of the project and customer.

Refer to *Tables 1-4* for utility cost allocations across programs, customer segments, and technologies

Refer to *Tables 5-6* for the allocations of electric and therm savings across customer segments and technologies.

Refer to *Tables 7-8* for the allocations of customer costs and non-energy benefits across customer segments and technologies.

Table 1

## Utility Costs Aggregated by Programs and Customer Segments

	Implementation	Incentives <sup>1</sup>	M&E	TOTAL
<b>SEGMENTS</b>				
Agricultural	\$ 8,219	\$ 32,470	\$ 3,193	\$ 43,882
Government	\$ 103,711	\$ 217,232	\$ 3,790	\$ 324,732
Food Service	\$ 19,305	\$ 7,164	\$ 2,945	\$ 29,413
Health Care	\$ 18,028	\$ 10,203	\$ 2,945	\$ 31,175
Hospitality	\$ 41,295	\$ 112,654	\$ 3,193	\$ 157,142
Limited Income	\$ 11,328	\$ 365,504	\$ -	\$ 376,832
Manufacturing	\$ 109,579	\$ 121,501	\$ 8,488	\$ 239,568
Office	\$ 29,621	\$ 27,155	\$ 7,269	\$ 64,044
Residential <sup>2</sup>	\$ 56,721	\$ 105,580	\$ 883	\$ 163,184
Retail	\$ 11,504	\$ 12,686	\$ 2,986	\$ 27,177
<b>GENERAL</b>				
General (Implementation)	\$ 624,022	\$ -	\$ -	\$ 624,022
General (M&E)	\$ -	\$ -	\$ 56,669	\$ 56,669
<b>OTHER EXPENDITURES</b>				
NEEA <sup>3</sup>	\$ 2,793	\$ 375,577	\$ -	\$ 378,370
Leases <sup>4</sup>	\$ 26,249	\$ -	\$ -	\$ 26,249
<b>OLD PROGRAMS</b>				
LED Traffic Signals	\$ -	\$ 3,120	\$ -	\$ 3,120
New Technologies	\$ 373	\$ 27,169	\$ -	\$ 27,543
Prescriptive HVAC	\$ -	\$ -	\$ -	\$ -
Prescriptive Lighting	\$ -	\$ 1,440	\$ -	\$ 1,440
RMFP	\$ -	\$ -	\$ -	\$ -
Site Specific	\$ 3,053	\$ 112,622	\$ -	\$ 115,675
SS-VFD	\$ -	\$ 35,577	\$ -	\$ 35,577
Trade Ally	\$ 345	\$ (4,930)	\$ -	\$ (4,585)
<b>TOTAL</b>	<b>\$ 1,066,145</b>	<b>\$ 1,562,724</b>	<b>\$ 92,361</b>	<b>\$ 2,721,230</b>
<b>BROKEN OUT BY CATEGORY</b>				
Total assigned to segments	\$ 409,310	\$ 1,012,148	\$ 35,692	\$ 1,457,151
Total assigned to general	\$ 624,022	\$ -	\$ 56,669	\$ 680,691
Total assigned to other	\$ 29,042	\$ 375,577	\$ -	\$ 404,619
Total assigned to old programs	\$ 3,771	\$ 174,998	\$ -	\$ 178,770
<b>TOTAL</b>	<b>\$ 1,066,145</b>	<b>\$ 1,562,724</b>	<b>\$ 92,361</b>	<b>\$ 2,721,230</b>
<b>CATEGORY AS A PERCENT</b>				
Total assigned to segment	15.0%	37.2%	1.3%	53.5%
Total assigned to general	22.9%	0.0%	2.1%	25.0%
Total assigned to other	1.1%	13.8%	0.0%	14.9%
Total assigned to old programs	0.1%	6.4%	0.0%	6.6%
<b>TOTAL</b>	<b>39.2%</b>	<b>57.4%</b>	<b>3.4%</b>	<b>100.0%</b>

**NOTES:**

- 1) Incentives are accounted for on an accrual basis, and are therefore de-rated (in the same way as kWh, therms, etc.)
- 2) Costs for this trimester's portion (1/3) of the Natural Gas Awareness Campaign are included in *Residential*.
- 3) Costs associated with membership in NEEA are included in this table, but are excluded from all other tables.
- 4) Costs associated with outstanding leases are included in this table, but are excluded from all other tables.
- 5) The Government segment includes educational institutions as well as federal, state and local governments.



Table 2

Assignment of Utility Costs to Customer Segments

	Assigned Impl. [A]	Assigned M&E [B]	Total util assigned non-incent \$ [C]	Gen impl allocated [D]	Gen M&E allocated [E]	Total alloc overhead [F]	Old pgm alloc		Total old pgm non-incent allocations [II]	TOTAL IMPL [J]	TOTAL M&E [K]	TOTAL INCENTIVE [L]	GRAND TOTAL [M]	Allocated ovhd as % of total [N]
							impl cost [G]	Old pgm alloc M&E cost [H]						
Agricultural	\$ 8,219	\$ 3,193	\$ 11,412	\$ 72,003	\$ 2,576	\$ 74,578	\$ -	\$ -	\$ -	\$ 80,222	\$ 5,769	\$ 32,470	\$ 118,460	63.0%
Government	\$ 103,711	\$ 3,790	\$ 107,500	\$ 48,002	\$ 10,303	\$ 58,305	\$ 345	\$ -	\$ 345	\$ 152,057	\$ 14,093	\$ 271,222	\$ 437,372	13.3%
Food Service	\$ 19,305	\$ 2,945	\$ 22,250	\$ 48,002	\$ 3,864	\$ 51,865	\$ 826	\$ -	\$ 826	\$ 68,132	\$ 6,809	\$ 6,039	\$ 80,980	64.0%
Health Care	\$ 18,028	\$ 2,945	\$ 20,973	\$ 72,003	\$ 2,576	\$ 74,578	\$ 2,366	\$ -	\$ 2,366	\$ 92,396	\$ 5,521	\$ 10,203	\$ 108,120	69.0%
Hospitality	\$ 41,295	\$ 3,193	\$ 44,488	\$ 72,003	\$ 3,864	\$ 75,866	\$ -	\$ -	\$ -	\$ 113,298	\$ 7,057	\$ 112,654	\$ 233,009	32.6%
Limited Income	\$ 11,328	\$ -	\$ 11,328	\$ 24,001	\$ 10,303	\$ 34,304	\$ -	\$ -	\$ -	\$ 35,329	\$ 10,303	\$ 365,504	\$ 411,136	8.3%
Manufacturing	\$ 109,579	\$ 8,488	\$ 118,067	\$ 72,003	\$ 5,152	\$ 77,154	\$ -	\$ -	\$ -	\$ 181,581	\$ 13,640	\$ 242,690	\$ 437,912	17.6%
Office	\$ 29,621	\$ 7,269	\$ 36,890	\$ 48,002	\$ 5,152	\$ 53,153	\$ 234	\$ -	\$ 234	\$ 77,857	\$ 12,421	\$ 28,099	\$ 118,376	44.9%
Residential	\$ 56,721	\$ 883	\$ 57,604	\$ 120,004	\$ 7,728	\$ 127,732	\$ -	\$ -	\$ -	\$ 176,725	\$ 8,611	\$ 107,995	\$ 293,331	43.5%
Retail	\$ 11,504	\$ 2,986	\$ 14,490	\$ 48,002	\$ 5,152	\$ 53,153	\$ -	\$ -	\$ -	\$ 59,506	\$ 8,138	\$ 12,686	\$ 80,330	66.2%
	<b>\$ 409,310</b>	<b>\$ 35,692</b>	<b>\$ 445,002</b>	<b>\$ 624,022</b>	<b>\$ 56,669</b>	<b>\$ 680,691</b>	<b>\$ 3,771</b>	<b>\$ -</b>	<b>\$ 3,771</b>	<b>\$ 1,037,104</b>	<b>\$ 92,361</b>	<b>\$ 1,189,562</b>	<b>\$ 2,319,026</b>	

- [A] The implementation cost charged directly to that customer segment.
- [B] The M&E cost charged directly to that customer segment.
- [C] The total utility non-incentive cost of the customer segment.
- [D] The general implementation cost allocated to the customer segment.
- [E] The general M&E cost allocated to the customer segment.
- [F] The total allocated general cost.
- [G] The implementation cost allocated from 'old programs' (those not specified as customer segments in the new tariff) to new customer segments.
- [H] The M&E cost allocated from 'old programs' (those not specified as customer segments in the new tariff) to new customer segments.
- [I] The total non-incentive cost allocated from old programs to new customer segments.
- [J] Total implementation cost for the customer segment, including allocated general cost and allocated implementation cost from old programs.
- [K] Total M&E cost for the customer segment, including allocated general M&E and allocated M&E cost from old programs.
- [L] Total incentives paid under both old programs and new segments during the trimester to customers within this customer segment.
- [M] Total utility cost (including incentives) for the customer segment.
- [N] The allocation of general implementation and M&E cost as a percent of the total program cost.

NOTES:

Incentives are accounted for on an accrual basis, and are therefore de-rated (in the same way as kWh, therms, etc.) Costs for this trimester's portion (1/3) of the Natural Gas Awareness Campaign are included in Residential. Costs associated with membership in NEEA are excluded from this table, and are excluded from all cost-effectiveness calculations. Costs associated with outstanding leases are excluded from this table, and are excluded from all cost-effectiveness calculations.

Table 3

Allocation of Utility Costs Across Customer Segments and Technologies

	Appliances	Assistive Technologies	Compressed Air	Controls	HVAC	Industrial Process	Lighting	Monitoring	Motors	New Tech	Renewables	Resource Management	Shell	Sustainable Building	TOTAL \$	% of Portfolio
Agricultural	\$ -	\$ -	\$ -	\$ 12,899	\$ 32,470	\$ 51,594	\$ 4,300	\$ 4,300	\$ 8,599	\$ 4,300	\$ -	\$ -	\$ -	\$ -	\$ 118,460	5.1%
Government	\$ -	\$ -	\$ -	\$ 171,809	\$ 18,738	\$ -	\$ 160,245	\$ 8,308	\$ 4,699	\$ 15,420	\$ -	\$ 58,153	\$ -	\$ -	\$ 437,372	18.9%
Food Service	\$ 4,479	\$ -	\$ -	\$ 15,228	\$ 22,482	\$ -	\$ 38,790	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 80,980	3.5%
Health Care	\$ -	\$ -	\$ -	\$ 33,411	\$ 59,063	\$ -	\$ 11,505	\$ -	\$ -	\$ 4,141	\$ -	\$ -	\$ -	\$ -	\$ 108,120	4.7%
Hospitality	\$ -	\$ -	\$ -	\$ 3,428	\$ 13,311	\$ -	\$ 84,535	\$ -	\$ -	\$ 119,700	\$ -	\$ 12,035	\$ -	\$ -	\$ 233,009	10.0%
Limited Income	\$ 123,122	\$ -	\$ -	\$ -	\$ 260,145	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 27,869	\$ -	\$ 411,136	17.7%
Manufacturing	\$ -	\$ -	\$ 47,309	\$ 135,861	\$ 19,924	\$ 155,995	\$ 20,079	\$ 19,522	\$ 9,761	\$ 19,898	\$ -	\$ -	\$ 9,761	\$ -	\$ 437,912	18.9%
Office	\$ -	\$ -	\$ -	\$ 23,866	\$ 33,562	\$ -	\$ 28,332	\$ -	\$ 1,598	\$ 20,981	\$ -	\$ 4,514	\$ 1,009	\$ 4,514	\$ 118,376	5.1%
Residential	\$ 64,868	\$ -	\$ -	\$ -	\$ 174,393	\$ -	\$ 39,482	\$ -	\$ -	\$ 14,588	\$ -	\$ -	\$ -	\$ -	\$ 293,331	12.6%
Retail	\$ -	\$ -	\$ -	\$ 24,481	\$ 6,764	\$ -	\$ 38,938	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 10,147	\$ -	\$ 80,330	3.5%
<b>TOTAL \$</b>	<b>\$ 192,469</b>	<b>\$ -</b>	<b>\$ 47,309</b>	<b>\$ 420,983</b>	<b>\$ 640,854</b>	<b>\$ 207,590</b>	<b>\$ 426,206</b>	<b>\$ 32,129</b>	<b>\$ 24,657</b>	<b>\$ 198,827</b>	<b>\$ -</b>	<b>\$ 74,702</b>	<b>\$ 48,785</b>	<b>\$ 4,514</b>	<b>\$ 2,319,026</b>	<b>100.0%</b>
% of portfolio	8.3%	0.0%	2.0%	18.2%	27.8%	9.0%	18.4%	1.4%	1.1%	8.6%	0.0%	3.2%	2.1%	0.2%		

NOTES:

Incentives are accounted for on an accrual basis, and are therefore de-rated (in the same way as kWh, therms, etc.) Costs for this trimester's portion (1/3) of the Natural Gas Awareness Campaign are included in Residential. Costs associated with membership in NEEA are excluded from this table, and are excluded from all cost-effectiveness calculations. Costs associated with outstanding leases are excluded from this table, and are excluded from all cost-effectiveness calculations.

**Table 4 Allocation of Direct Incentives Across Customer Segments and Technologies**

	Appliances	Assistive Technologies	Compressed Air	Controls	HVAC	Industrial Process	Lighting	Monitoring	Motors	New Tech	Renewables	Resource Management	Shell	Sustainable Building	TOTAL \$	% of Portfolio
Agricultural	\$ -	\$ -	\$ -	\$ -	\$ 32,470	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 32,470	2.7%
Government	\$ -	\$ -	\$ -	\$ 163,502	\$ 2,123	\$ -	\$ 85,477	\$ -	\$ 4,599	\$ 15,420	\$ -	\$ -	\$ -	\$ -	\$ 271,222	22.8%
Food Service	\$ 4,479	\$ -	\$ -	\$ 240	\$ -	\$ -	\$ 1,319	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 6,039	0.5%
Health Care	\$ -	\$ -	\$ -	\$ 4,036	\$ 313	\$ -	\$ 1,713	\$ -	\$ -	\$ 4,141	\$ -	\$ -	\$ -	\$ -	\$ 10,203	0.9%
Hospitality	\$ -	\$ -	\$ -	\$ 3,428	\$ 13,311	\$ -	\$ 30,375	\$ -	\$ -	\$ 65,540	\$ -	\$ -	\$ -	\$ -	\$ 112,654	9.5%
Limited Income	\$ 111,714	\$ -	\$ -	\$ -	\$ 237,329	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 16,461	\$ -	\$ 365,504	30.7%
Manufacturing	\$ -	\$ -	\$ 18,026	\$ 87,056	\$ 402	\$ 136,473	\$ 557	\$ -	\$ -	\$ 176	\$ -	\$ -	\$ -	\$ -	\$ 242,690	20.4%
Office	\$ -	\$ -	\$ -	\$ 1,297	\$ 10,993	\$ -	\$ 1,249	\$ -	\$ 1,598	\$ 11,953	\$ -	\$ -	\$ 1,009	\$ -	\$ 28,099	2.4%
Residential	\$ -	\$ -	\$ -	\$ -	\$ 90,992	\$ -	\$ 2,415	\$ -	\$ -	\$ 14,588	\$ -	\$ -	\$ -	\$ -	\$ 107,995	9.1%
Retail	\$ -	\$ -	\$ -	\$ 14,334	\$ -	\$ -	\$ (1,648)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 12,686	1.1%
<b>TOTAL \$</b>	<b>\$ 116,194</b>	<b>\$ -</b>	<b>\$ 18,026</b>	<b>\$ 273,893</b>	<b>\$ 387,934</b>	<b>\$ 136,473</b>	<b>\$ 121,458</b>	<b>\$ -</b>	<b>\$ 6,297</b>	<b>\$ 111,818</b>	<b>\$ -</b>	<b>\$ -</b>	<b>\$ 17,470</b>	<b>\$ -</b>	<b>\$ 1,189,562</b>	<b>100.0%</b>
% of portfolio	9.8%	0.0%	1.5%	23.0%	32.6%	11.5%	10.2%	0.0%	0.5%	9.4%	0.0%	0.0%	1.5%	0.0%	100.0%	

**NOTES:**

Incentives are accounted for on an accrual basis, and are therefore de-rated (in the same way as kWh, therms, etc.) Incentive costs for this trimester's portion (1/3) of the Natural Gas Awareness Campaign are included in Residential. Incentive costs associated with membership in NEEA are excluded from this table, and are excluded from all cost-effectiveness calculations. Incentive costs associated with outstanding leases are excluded from this table, and are excluded from all cost-effectiveness calculations.

**Table 5** Allocation of Electric Savings Across Customer Segments and Technologies

	Appliances	Assistive Technologies	Compressed Air	Controls	HVAC	Industrial Process	Lighting	Monitoring	Motors	New Tech	Renewables	Resource Management	Shell	Sustainable Building	TOTAL kWh	% of Portfolio
Agricultural	-	-	-	-	750,100	-	-	-	-	-	-	-	-	-	750,100	4.4%
Government	-	-	-	2,849,176	141,554	-	1,195,792	-	58,742	195,811	-	62,007	-	-	4,503,082	26.6%
Food Service	111,983	-	-	340,544	-	-	286,074	-	-	-	-	-	-	-	738,601	4.4%
Health Care	-	-	-	54,348	3,914	-	42,817	-	-	29,575	-	-	-	-	130,654	0.8%
Hospitality	-	-	-	37,500	443,739	-	509,363	-	-	594,346	-	-	-	-	1,584,949	9.3%
Limited Income	567,883	-	-	-	1,142,087	-	-	-	-	-	-	-	28,065	-	1,738,035	10.3%
Manufacturing	-	-	833,442	1,707,075	5,027	2,265,250	9,289	-	-	1,600	-	-	-	-	4,821,682	28.4%
Office	-	-	-	(37,177)	149,075	-	(241,820)	-	26,633	93,106	-	-	12,561	-	2,379	0.0%
Residential	460,187	-	-	-	1,803,241	-	102,651	-	-	106,620	-	-	-	-	2,472,699	14.6%
Retail	-	-	-	261,916	-	-	(51,901)	-	-	-	-	-	-	-	210,015	1.2%
<b>TOTAL kWh</b>	<b>1,140,053</b>	<b>-</b>	<b>833,442</b>	<b>5,213,382</b>	<b>4,438,737</b>	<b>2,265,250</b>	<b>1,852,266</b>	<b>-</b>	<b>85,375</b>	<b>1,021,059</b>	<b>-</b>	<b>62,007</b>	<b>40,626</b>	<b>-</b>	<b>16,952,196</b>	<b>100.0%</b>
% of portfolio	6.7%	0.0%	4.9%	30.8%	28.2%	13.4%	10.9%	0.0%	0.5%	6.0%	0.0%	0.4%	0.2%	0.0%	100.0%	

NOTE: These figures include de-rated electric savings from the Contracted and Construction phases.

**Table 6** Allocation of Natural Gas Savings Across Customer Segments and Technologies

	Appliances	Assistive Technologies	Compressed Air	Controls	HVAC	Industrial Process	Lighting	Monitoring	Motors	New Tech	Renewables	Resource Management	Shell	Sustainable Building	TOTAL	% of Portfolio
Agricultural	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0%
Government	-	-	-	37,759	(4,351)	-	(7,351)	-	-	-	-	(41,038)	-	-	(15,002)	9.0%
Food Service	-	-	-	-	-	-	(440)	-	-	-	-	-	-	-	(440)	0.3%
Health Care	-	-	-	7,613	-	-	(316)	-	-	-	-	-	-	-	7,297	-4.4%
Hospitality	-	-	-	-	-	-	(2,370)	-	-	-	-	-	-	-	(2,370)	1.4%
Limited Income	(24,220)	-	-	-	(48,710)	-	-	-	-	-	-	-	(1,197)	-	(74,127)	44.7%
Manufacturing	-	-	-	-	-	1,275	(68)	-	-	-	-	-	-	-	1,207	-0.7%
Office	(19,633)	-	-	-	(76,402)	-	-	-	-	-	-	-	13,226	-	(96,034)	57.9%
Residential	-	-	-	-	-	-	-	-	-	-	-	-	-	-	422	-0.3%
<b>TOTAL</b>	<b>(43,853)</b>	<b>-</b>	<b>833,442</b>	<b>45,351</b>	<b>(128,463)</b>	<b>1,275</b>	<b>(10,123)</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>(41,038)</b>	<b>12,029</b>	<b>-</b>	<b>(165,821)</b>	<b>100.0%</b>
% of portfolio	26.4%	0.0%	0.0%	-27.3%	78.1%	-0.8%	6.1%	0.0%	0.0%	0.0%	0.0%	24.7%	-7.3%	0.0%	100.0%	

NOTE: These figures include de-rated natural gas savings from the Contracted and Construction phases.

**Table 7** Allocation of Non-Energy Benefits Across Customer Segments and Technologies

	Appliances	Assistive Technologies	Compressed Air	Controls	HVAC	Industrial Process	Lighting	Monitoring	Motors	New Tech	Renewables	Resource Management	Shell	Sustainable Building	TOTAL NEB \$	% of Portfolio
Agricultural	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	0.0%
Government	\$ -	\$ -	\$ -	\$ 39,164	\$ -	\$ -	\$ 147,750	\$ -	\$ -	\$ 197,368	\$ -	\$ -	\$ -	\$ -	\$ 384,282	19.2%
Food Service	\$ -	\$ -	\$ -	\$ 219	\$ -	\$ -	\$ 2,436	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 2,655	0.1%
Health Care	\$ -	\$ -	\$ -	\$ 3,700	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 3,700	0.2%
Hospitality	\$ -	\$ -	\$ -	\$ 3,136	\$ -	\$ -	\$ 68,097	\$ -	\$ -	\$ 11,639	\$ -	\$ -	\$ -	\$ -	\$ 82,872	4.1%
Limited Income	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	0.0%
Manufacturing	\$ -	\$ -	\$ -	\$ 3,669	\$ -	\$ 1,149,655	\$ 5,746	\$ -	\$ -	\$ 2,388	\$ -	\$ -	\$ -	\$ -	\$ 1,161,458	58.0%
Office	\$ -	\$ -	\$ -	\$ 6,585	\$ -	\$ -	\$ (9,149)	\$ -	\$ -	\$ 30,023	\$ -	\$ -	\$ 319,986	\$ -	\$ 347,445	17.4%
Residential	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 9,878	\$ -	\$ -	\$ -	\$ -	\$ 9,878	0.5%
Retail	\$ -	\$ -	\$ -	\$ 6,303	\$ -	\$ -	\$ 3,069	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 9,372	0.5%
<b>TOTAL NEB \$</b>	<b>\$ -</b>	<b>\$ -</b>	<b>\$ -</b>	<b>\$ 62,775</b>	<b>\$ -</b>	<b>\$ 1,149,655</b>	<b>\$ 217,949</b>	<b>\$ -</b>	<b>\$ -</b>	<b>\$ 251,297</b>	<b>\$ -</b>	<b>\$ -</b>	<b>\$ 319,986</b>	<b>\$ -</b>	<b>\$ 2,001,662</b>	<b>100.0%</b>
% of portfolio	0.0%	0.0%	0.0%	3.1%	0.0%	57.4%	10.9%	0.0%	0.0%	12.6%	0.0%	0.0%	16.0%	0.0%	100.0%	

NOTE: The non-energy benefit figures contained in this table are listed as net present value (NPV).

**Table 8** Allocation of Customer Costs Across Customer Segments and Technologies

	Appliances	Assistive Technologies	Compressed Air	Controls	HVAC	Industrial Process	Lighting	Monitoring	Motors	New Tech	Renewables	Resource Management	Shell	Sustainable Building	TOTAL NEB \$	% of Portfolio
Agricultural	\$ -	\$ -	\$ -	\$ -	\$ 91,000	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 91,000	3.1%
Government	\$ -	\$ -	\$ -	\$ 733,989	\$ 9,241	\$ -	\$ 342,110	\$ -	\$ 28,667	\$ 37,041	\$ -	\$ -	\$ -	\$ -	\$ 1,151,047	39.2%
Food Service	\$ 9,131	\$ -	\$ -	\$ 280	\$ -	\$ -	\$ 12,469	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 21,881	0.7%
Health Care	\$ -	\$ -	\$ -	\$ 15,822	\$ 3,834	\$ -	\$ 5,276	\$ -	\$ -	\$ 26,463	\$ -	\$ -	\$ -	\$ -	\$ 51,395	1.7%
Hospitality	\$ -	\$ -	\$ -	\$ 4,930	\$ 4,109	\$ -	\$ 122,898	\$ -	\$ -	\$ 124,009	\$ -	\$ -	\$ -	\$ -	\$ 255,945	8.7%
Limited Income	\$ 111,714	\$ -	\$ -	\$ -	\$ 237,329	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 365,504	12.4%
Manufacturing	\$ -	\$ -	\$ 51,359	\$ 5,895	\$ 7,775	\$ 301,582	\$ 4,013	\$ -	\$ -	\$ 394	\$ -	\$ -	\$ 16,461	\$ -	\$ 371,018	12.6%
Office	\$ -	\$ -	\$ -	\$ (184,801)	\$ 67,042	\$ -	\$ (91,323)	\$ -	\$ 15,450	\$ 4,950	\$ -	\$ -	\$ 99,162	\$ -	\$ (89,520)	-3.0%
Residential	\$ 145,515	\$ -	\$ -	\$ 750	\$ 455,279	\$ -	\$ 10,860	\$ -	\$ -	\$ 76,322	\$ -	\$ -	\$ -	\$ -	\$ 688,725	23.4%
Retail	\$ -	\$ -	\$ -	\$ 31,671	\$ -	\$ -	\$ (964)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 30,707	1.0%
<b>TOTAL NEB \$</b>	<b>\$ 266,360</b>	<b>\$ -</b>	<b>\$ 51,359</b>	<b>\$ 608,536</b>	<b>\$ 875,608</b>	<b>\$ 301,582</b>	<b>\$ 405,340</b>	<b>\$ -</b>	<b>\$ 44,117</b>	<b>\$ 289,179</b>	<b>\$ -</b>	<b>\$ -</b>	<b>\$ 115,623</b>	<b>\$ -</b>	<b>\$ 2,937,703</b>	<b>100.0%</b>
% of portfolio	9.1%	0.0%	1.7%	20.7%	29.8%	10.3%	13.8%	0.0%	1.5%	9.2%	0.0%	0.0%	3.9%	0.0%	100.0%	

NOTE: The customer cost figures contained in this table are not adjusted for incentives received. Instead, they reflect the entire de-rated cost of the energy efficiency project.

Cost-Effectiveness Calculations

The cost-effectiveness calculations are completed based upon the industry-standard California Standard Practice Manual for each of the four tests.

Quantifiable non-energy benefits are included in these calculations. Avista has been aggressive in identifying these non-energy benefits where they are quantifiable.

The largest non-energy benefit has usually taken the form of quantifiable deferred capital expenditures on the part of the customer (resulting from replacing an existing end-use with a limited life remaining with a high-efficiency alternative with a substantially longer life). A methodology for quantifying this substantial benefit for inclusion in cost-effectiveness calculations was under development during this trimester but was not applied to the calculations for this report.

Maintenance savings, particularly for lighting end-uses, have also been significant.

To date Avista has not found a sufficiently rigorous calculation of other non-energy benefits (productivity, security etc.) to include them in the calculation of cost-effectiveness. To the extent that these benefits are non-quantifiable the resulting cost-effectiveness calculations are conservative.

Refer to *Tables 9 and 10* for summaries of cost-effectiveness results by customer segment and technology.

Refer to *Tables 11 and 12* for summaries of net benefits by customer segments and technologies.

Refer to *Table 13* for further details on the calculation of the cost-effectiveness ratios and related descriptive statistics.

**Table 9** **Cost-Effectiveness Statistics by Customer Segment**

	Total Resource <u>Cost Test</u>	Utility Cost <u>Test</u>	Participant <u>Test</u>	Non- Participant <u>Test</u>
Agricultural	1.22	1.82	8.20	0.36
Government	0.93	1.93	2.17	0.44
Food Service	1.43	1.68	15.24	0.43
Health Care	0.30	0.38	1.84	0.16
Hospitality	1.20	1.59	4.71	0.45
Limited Income	0.44	0.44	N/A	0.31
Manufacturing	3.50	1.87	19.98	0.44
Office	594.38	0.87	(4.31)	0.16
Residential	0.49	1.43	1.97	0.39
Retail	0.41	0.38	4.89	0.19
<b>PORTFOLIO</b>	<b>1.27</b>	<b>1.36</b>	<b>4.89</b>	<b>0.39</b>

**Table 10** **Cost-Effectiveness Statistics by Technology**

	Total Resource <u>Cost Test</u>	Utility Cost <u>Test</u>	Participant <u>Test</u>	Non- Participant <u>Test</u>
Appliances	0.80	1.42	3.09	0.44
Assistive Technologies	N/A	N/A	N/A	N/A
Compressed Air	1.73	2.95	8.34	0.43
Controls	1.37	2.95	5.00	0.46
HVAC	0.67	1.17	4.71	0.36
Industrial Process	4.22	2.04	11.23	0.46
Lighting	0.80	0.82	3.18	0.33
Monitoring	-	-	N/A	-
Motors	0.39	0.99	1.64	0.28
New Tech	1.24	0.96	3.93	0.34
Renewables	N/A	N/A	N/A	N/A
Resource Management	(0.70)	(0.70)	N/A	0.03
Shell	2.73	1.67	4.44	0.17
Sustainable Building	-	-	N/A	-
<b>PORTFOLIO</b>	<b>1.27</b>	<b>1.36</b>	<b>4.89</b>	<b>0.39</b>

**NOTES:**

Costs for this trimester's portion (1/3) of the Natural Gas Awareness Campaign are included in *Residential*.

Costs associated with membership in NEEA are excluded from all cost-effectiveness calculations.

Costs associated with outstanding leases are excluded from all cost-effectiveness calculations.

"N/A" is listed for segments and technologies with benefits, but no costs.

Table 11

## Net Benefits by Customer Segment

	Total Resource Cost Test	Utility Cost Test	Participant Test	Non- Participant Test
Agricultural	\$ 38,197	\$ 96,727	\$ 421,213	\$ (383,016)
Government	\$ (87,935)	\$ 407,609	\$ 1,027,946	\$ (1,100,751)
Food Service	\$ 41,513	\$ 54,700	\$ 225,517	\$ (183,855)
Health Care	\$ (104,491)	\$ (66,998)	\$ 34,751	\$ (131,341)
Hospitality	\$ 76,298	\$ 136,717	\$ 532,149	\$ (453,098)
Limited Income	\$ (231,855)	\$ (231,855)	\$ 858,269	\$ (1,213,556)
Manufacturing	\$ 1,413,317	\$ 380,186	\$ 2,435,154	\$ (1,021,750)
Office	\$ 449,408	\$ (15,655)	\$ 624,141	\$ (153,705)
Residential	\$ (444,004)	\$ 126,848	\$ 562,438	\$ (1,212,046)
Retail	\$ (58,361)	\$ (49,711)	\$ 70,169	\$ (127,922)
<b>PORTFOLIO</b>	<b>\$ 1,092,087</b>	<b>\$ 838,567</b>	<b>\$ 6,791,747</b>	<b>\$ (5,981,040)</b>

Table 12

## Net Benefits by Technology

	Total Resource Cost Test	Utility Cost Test	Participant Test	Non- Participant Test
Appliances	\$ (68,577)	\$ 81,590	\$ 313,567	\$ (500,858)
Assistive Technologies	\$ -	\$ -	\$ -	\$ -
Compressed Air	\$ 58,924	\$ 92,257	\$ 244,619	\$ (185,696)
Controls	\$ 281,161	\$ 553,028	\$ 1,339,189	\$ (1,029,915)
HVAC	\$ (376,727)	\$ 110,948	\$ 1,807,980	\$ (2,396,107)
Industrial Process	\$ 1,201,158	\$ 216,612	\$ 1,688,834	\$ (487,547)
Lighting	\$ (143,521)	\$ (77,588)	\$ 620,079	\$ (757,825)
Monitoring	\$ (32,129)	\$ (32,129)	\$ -	\$ (32,129)
Motors	\$ (37,984)	\$ (165)	\$ 24,155	\$ (62,139)
New Tech	\$ 86,831	\$ (7,105)	\$ 461,446	\$ (374,614)
Renewables	\$ -	\$ -	\$ -	\$ -
Resource Management	\$ (126,953)	\$ (126,953)	\$ (45,545)	\$ (85,724)
Shell	\$ 254,418	\$ 32,586	\$ 337,423	\$ (63,971)
Sustainable Building	\$ (4,514)	\$ (4,514)	\$ -	\$ (4,514)
<b>PORTFOLIO</b>	<b>\$ 1,092,087</b>	<b>\$ 838,567</b>	<b>\$ 6,791,747</b>	<b>\$ (5,981,040)</b>

**NOTES:**

Net benefits are calculated by subtracting costs from benefits.

Costs and benefits included in each cost-effectiveness test are detailed in Table 13.

Costs for this trimester's portion (1/3) of the Natural Gas Awareness Campaign are included in *Residential*.

Costs associated with membership in NEEA are excluded from all cost-effectiveness calculations.

Costs associated with outstanding leases are excluded from all cost-effectiveness calculations.



Table 13

## Summary of Cost-Effectiveness Tests and Descriptive Statistics

<u>Total Resource Cost Test</u>	Regular Income	Limited Income	Overall	<u>Utility Cost Test</u>	Regular Income	Limited Income	Overall
	<u>portfolio</u>	<u>portfolio</u>	<u>portfolio</u>		<u>portfolio</u>	<u>portfolio</u>	<u>portfolio</u>
Electric avoided cost	\$ 3,266,327	\$ 532,751	\$ 3,799,079	Electric avoided cost	\$ 3,266,327	\$ 532,751	\$ 3,799,079
Non-Energy benefits	\$ 2,001,662	\$ -	\$ 2,001,662	Natural Gas avoided cost	\$ (288,016)	\$ (353,470)	\$ (641,486)
Natural Gas avoided cost	\$ (288,016)	\$ (353,470)	\$ (641,486)	UCT benefits	\$ 2,978,312	\$ 179,281	\$ 3,157,593
TRC benefits	\$ 4,979,974	\$ 179,281	\$ 5,159,255	Non-incentive utility cost	\$ 1,083,832	\$ 45,632	\$ 1,129,464
Non-incentive utility cost	\$ 1,083,832	\$ 45,632	\$ 1,129,464	Incentive cost	\$ 824,057	\$ 365,504	\$ 1,189,562
Customer cost	\$ 2,572,199	\$ 365,504	\$ 2,937,703	UCT costs	\$ 1,907,890	\$ 411,136	\$ 2,319,026
TRC costs	\$ 3,656,031	\$ 411,136	\$ 4,067,167	UCT ratio	1.56	0.44	1.36
TRC ratio	1.36	0.44	1.27	Net UCT benefits	\$ 1,070,422	\$ (231,855)	\$ 838,567
Net TRC benefits	\$ 1,323,943	\$ (231,855)	\$ 1,092,087				

<u>Participant Test</u>	Regular Income	Limited Income	Overall	<u>Non-Participant Test</u>	Regular Income	Limited Income	Overall
	<u>portfolio</u>	<u>portfolio</u>	<u>portfolio</u>		<u>portfolio</u>	<u>portfolio</u>	<u>portfolio</u>
Bill Reduction	\$ 5,679,957	\$ 858,269	\$ 6,538,227	Electric avoided cost savings	\$ 3,266,327	\$ 532,751	\$ 3,799,079
Non-Energy benefits	\$ 2,001,662	\$ -	\$ 2,001,662	Non-Part benefits	\$ 3,266,327	\$ 532,751	\$ 3,799,079
Participant benefits	\$ 7,681,619	\$ 858,269	\$ 8,539,889	Revenue loss	\$ 6,125,922	\$ 1,335,171	\$ 7,461,092
Customer project cost	\$ 2,572,199	\$ 365,504	\$ 2,937,703	Non-incentive utility cost	\$ 1,083,832	\$ 45,632	\$ 1,129,464
Incentive received	\$ 824,057	\$ 365,504	\$ 1,189,562	Customer incentives	\$ 824,057	\$ 365,504	\$ 1,189,562
Participant costs	\$ 1,748,141	\$ -	\$ 1,748,141	Non-Part costs	\$ 8,033,811	\$ 1,746,307	\$ 9,780,118
Participant Test ratio	4.39	N/A	4.89	Non-Part. ratio	0.41	0.31	0.39
Net Participant benefits	\$ 5,933,478	\$ 858,269	\$ 6,791,747	Net Non-Part. benefits	\$ (4,767,484)	\$ (1,213,556)	\$ (5,981,040)

<u>Descriptive Statistics</u>	Regular Income	Limited Income	Overall
	<u>portfolio</u>	<u>portfolio</u>	<u>portfolio</u>
Annual kWh savings	15,214,161	1,738,035	16,952,196
Customer cost/kWh	\$ 0.17	\$ 0.21	\$ 0.17
Non-incentive utility cost/kWh	\$ 0.07	\$ 0.03	\$ 0.07
Electric avoided cost/kWh	\$ 0.21	\$ 0.31	\$ 0.22
Incentive cost/kWh	\$ 0.05	\$ 0.21	\$ 0.07

**NOTES:**

Costs for this trimester's portion (1/3) of the Natural Gas Awareness Campaign are included in *Residential*.

Costs associated with membership in NEEA are excluded from all cost-effectiveness calculations.

Costs associated with outstanding leases are excluded from all cost-effectiveness calculations.

"N/A" is listed for segments and technologies with benefits, but no costs.

### Energy-Efficiency Tariff Rider Balance Calculations

The Energy-Efficiency Tariff Rider balance has been reduced by over 50% during the course of this trimester. Within Washington the ending balance fell by 45%, as opposed to Idaho (where the Rider was reduced to 1.0% in August, 1999) where the balance fell by 77%.

It is anticipated that the Idaho Energy-Efficiency Tariff Rider balance will reach zero by the end of September, 2000. To date, there has been no change in the level of program delivery to Idaho in spite of the reduced Rider level.

The Washington balance is projected to reach zero by the Spring 2001.

Refer to *Table 14* for the most recent update to our Tariff Rider balance calculation.

Table 14

Calculation of Energy Efficiency Tariff Rider Balance and Interest

Month	Washington		Washington		Washington		Washington		Idaho		Idaho		Idaho	
	DSM Expenditures	DSM Revenues	Beginning DSM balance	Ending DSM balance	Washington Interest	Ending bal. with interest	Beginning DSM balance	Ending DSM balance	Idaho Beginning DSM balance	Idaho Ending DSM balance	Idaho Interest	Ending bal. with interest	Idaho Interest	Ending bal. with interest
January 1999	\$ 171,037	\$ 371,658	\$ 2,617,016	\$ 2,817,637	\$ 10,950	\$ 2,828,586	\$ 2,617,016	\$ 2,817,637	\$ 1,453,579	\$ 1,445,337	\$ 2,385	\$ 1,147,722	\$ 2,385	\$ 1,147,722
February	\$ 188,863	\$ 321,483	\$ 2,828,586	\$ 2,961,216	\$ 23,068	\$ 2,982,885	\$ 2,828,586	\$ 2,961,216	\$ 1,147,722	\$ 1,204,273	\$ 8,767	\$ 1,213,040	\$ 8,767	\$ 1,213,040
March	\$ 416,803	\$ 292,771	\$ 2,982,885	\$ 2,858,853	\$ 23,084	\$ 2,881,937	\$ 2,858,853	\$ 2,858,853	\$ 1,213,040	\$ 1,289,438	\$ 9,378	\$ 1,308,815	\$ 9,378	\$ 1,308,815
April	\$ 781,855	\$ 266,606	\$ 2,881,937	\$ 2,366,688	\$ 23,291	\$ 2,389,979	\$ 2,366,688	\$ 2,366,688	\$ 1,308,815	\$ 1,172,629	\$ 10,017	\$ 1,182,647	\$ 10,017	\$ 1,182,647
May	\$ 333,288	\$ 247,454	\$ 2,389,979	\$ 2,304,165	\$ 20,927	\$ 2,325,092	\$ 2,304,165	\$ 2,304,165	\$ 1,172,629	\$ 1,172,644	\$ 9,894	\$ 1,182,538	\$ 9,894	\$ 1,182,538
June	\$ 283,079	\$ 296,981	\$ 2,325,092	\$ 2,308,994	\$ 18,716	\$ 2,327,710	\$ 2,308,994	\$ 2,308,994	\$ 1,182,538	\$ 1,264,521	\$ 9,391	\$ 1,226,165	\$ 9,391	\$ 1,226,165
July	\$ 315,854	\$ 237,115	\$ 2,327,710	\$ 2,248,971	\$ 18,476	\$ 2,267,447	\$ 2,248,971	\$ 2,248,971	\$ 1,264,521	\$ 1,220,902	\$ 9,966	\$ 1,274,087	\$ 9,966	\$ 1,274,087
August	\$ 470,627	\$ 272,035	\$ 2,267,447	\$ 2,068,855	\$ 18,248	\$ 2,087,102	\$ 2,068,855	\$ 2,068,855	\$ 1,220,902	\$ 1,274,087	\$ 9,931	\$ 1,220,902	\$ 9,931	\$ 1,220,902
September	\$ 220,534	\$ 302,045	\$ 2,087,102	\$ 2,168,613	\$ 17,289	\$ 2,185,903	\$ 2,168,613	\$ 2,168,613	\$ 1,274,087	\$ 1,221,021	\$ 9,908	\$ 1,230,929	\$ 9,908	\$ 1,230,929
October	\$ 333,763	\$ 260,080	\$ 2,185,903	\$ 2,112,220	\$ 17,333	\$ 2,129,553	\$ 2,112,220	\$ 2,112,220	\$ 1,221,021	\$ 1,007,955	\$ 9,736	\$ 1,017,691	\$ 9,736	\$ 1,017,691
November	\$ 174,943	\$ 263,916	\$ 2,129,553	\$ 2,218,161	\$ 17,137	\$ 2,235,298	\$ 2,218,161	\$ 2,218,161	\$ 1,017,691	\$ 935,206	\$ 8,927	\$ 944,132	\$ 8,927	\$ 944,132
December	\$ 759,358	\$ 317,111	\$ 2,235,298	\$ 1,793,053	\$ 17,333	\$ 1,810,386	\$ 1,793,053	\$ 1,793,053	\$ 944,132	\$ 739,552	\$ 7,786	\$ 747,338	\$ 7,786	\$ 747,338
January 2000	\$ 261,424	\$ 350,395	\$ 1,810,386	\$ 1,899,357	\$ 16,061	\$ 1,915,419	\$ 1,899,357	\$ 1,899,357	\$ 747,338	\$ 666,973	\$ 6,713	\$ 673,686	\$ 6,713	\$ 673,686
February	\$ 296,815	\$ 318,411	\$ 1,915,419	\$ 1,937,014	\$ 14,791	\$ 1,951,805	\$ 1,937,014	\$ 1,937,014	\$ 673,686	\$ 705,407	\$ 5,639	\$ 711,046	\$ 5,639	\$ 711,046
March	\$ 566,151	\$ 296,857	\$ 1,951,805	\$ 1,682,511	\$ 15,360	\$ 1,697,871	\$ 1,682,511	\$ 1,682,511	\$ 711,046	\$ 605,780	\$ 5,499	\$ 611,278	\$ 5,499	\$ 611,278
1999 totals	\$ 4,449,983	\$ 3,419,265	\$ 22,408	\$ 22,408	\$ 46,212	\$ 46,212	\$ 22,408	\$ 22,408	\$ 1,398,284	\$ 1,398,284	\$ 105,685	\$ 105,685	\$ 105,685	\$ 105,685
2000 totals	\$ 1,124,390	\$ 965,663	\$ 224,088	\$ 224,088	\$ 46,212	\$ 46,212	\$ 224,088	\$ 224,088	\$ 313,469	\$ 313,469	\$ 17,850	\$ 17,850	\$ 17,850	\$ 17,850

Month	Combined		Combined		Combined		Combined		Combined		Combined	
	DSM Expenditures	DSM Revenues	Beginning DSM balance	Ending DSM balance	Combined Interest	Ending bal. with interest	Beginning DSM balance	Ending DSM balance	Washington Interest	Idaho Interest	Washington Interest	Idaho Interest
January 1999	\$ 241,185	\$ 533,563	\$ 3,670,595	\$ 3,962,973	\$ 13,335	\$ 3,976,308	\$ 3,670,595	\$ 3,962,973	\$ 13,335	\$ 3,976,308	\$ 13,335	\$ 3,976,308
February	\$ 285,483	\$ 478,664	\$ 3,976,308	\$ 4,165,489	\$ 30,436	\$ 4,195,925	\$ 3,976,308	\$ 4,165,489	\$ 30,436	\$ 4,195,925	\$ 30,436	\$ 4,195,925
March	\$ 473,969	\$ 436,334	\$ 4,195,925	\$ 4,158,290	\$ 32,462	\$ 4,190,752	\$ 4,158,290	\$ 4,158,290	\$ 32,462	\$ 4,190,752	\$ 32,462	\$ 4,190,752
April	\$ 1,060,790	\$ 399,355	\$ 4,190,752	\$ 3,589,317	\$ 33,309	\$ 3,572,626	\$ 3,589,317	\$ 3,589,317	\$ 33,309	\$ 3,572,626	\$ 33,309	\$ 3,572,626
May	\$ 484,956	\$ 369,140	\$ 3,572,626	\$ 3,476,809	\$ 30,820	\$ 3,507,630	\$ 3,476,809	\$ 3,476,809	\$ 30,820	\$ 3,507,630	\$ 30,820	\$ 3,507,630
June	\$ 370,828	\$ 388,967	\$ 3,507,630	\$ 3,525,768	\$ 28,107	\$ 3,553,875	\$ 3,507,630	\$ 3,525,768	\$ 28,107	\$ 3,553,875	\$ 28,107	\$ 3,553,875
July	\$ 396,516	\$ 358,133	\$ 3,553,875	\$ 3,513,492	\$ 28,043	\$ 3,541,534	\$ 3,513,492	\$ 3,513,492	\$ 28,043	\$ 3,541,534	\$ 28,043	\$ 3,541,534
August	\$ 616,726	\$ 355,018	\$ 3,541,534	\$ 3,279,826	\$ 28,178	\$ 3,308,004	\$ 3,279,826	\$ 3,279,826	\$ 28,178	\$ 3,308,004	\$ 28,178	\$ 3,308,004
September	\$ 306,419	\$ 388,049	\$ 3,308,004	\$ 3,389,635	\$ 27,197	\$ 3,416,832	\$ 3,389,635	\$ 3,389,635	\$ 27,197	\$ 3,416,832	\$ 27,197	\$ 3,416,832
October	\$ 638,308	\$ 341,651	\$ 3,416,832	\$ 3,120,175	\$ 26,704	\$ 3,146,879	\$ 3,120,175	\$ 3,120,175	\$ 26,704	\$ 3,146,879	\$ 26,704	\$ 3,146,879
November	\$ 342,820	\$ 349,307	\$ 3,146,879	\$ 3,153,966	\$ 26,064	\$ 3,179,430	\$ 3,146,879	\$ 3,153,966	\$ 26,064	\$ 3,179,430	\$ 26,064	\$ 3,179,430
December	\$ 1,068,194	\$ 419,368	\$ 3,179,430	\$ 2,532,604	\$ 25,120	\$ 2,557,724	\$ 2,532,604	\$ 2,532,604	\$ 25,120	\$ 2,557,724	\$ 25,120	\$ 2,557,724
January 2000	\$ 435,516	\$ 444,122	\$ 2,557,724	\$ 2,566,330	\$ 22,774	\$ 2,589,105	\$ 2,566,330	\$ 2,566,330	\$ 22,774	\$ 2,589,105	\$ 22,774	\$ 2,589,105
February	\$ 389,463	\$ 442,780	\$ 2,589,105	\$ 2,642,421	\$ 20,430	\$ 2,662,851	\$ 2,642,421	\$ 2,642,421	\$ 20,430	\$ 2,662,851	\$ 20,430	\$ 2,662,851
March	\$ 766,790	\$ 392,230	\$ 2,662,851	\$ 2,288,291	\$ 20,858	\$ 2,309,150	\$ 2,288,291	\$ 2,288,291	\$ 20,858	\$ 2,309,150	\$ 20,858	\$ 2,309,150
1999 totals	\$ 6,260,189	\$ 4,817,549	\$ 329,773	\$ 329,773	\$ 64,063	\$ 64,063	\$ 329,773	\$ 329,773	\$ 64,063	\$ 64,063	\$ 64,063	\$ 64,063
2000 YTD totals	\$ 1,591,769	\$ 1,279,132	\$ 224,088	\$ 224,088	\$ 46,212	\$ 46,212	\$ 224,088	\$ 224,088	\$ 46,212	\$ 46,212	\$ 46,212	\$ 46,212

DSM balance reduction in most recent twelve months:

Rev-Exp	Exp./Rev	% balance reduction
Washington \$ (1,398,663)	141%	\$ 1,184,066 41%
Idaho \$ (600,543)	184%	\$ 697,537 59%
System \$ (2,199,206)	147%	\$ 1,881,602 45%

NOTES:  
Interest calculations have been revised to be based upon the prior month's balances, per the one month lag incorporated into the filed accounting guidelines. January interest reflects the adjustment to annual 1995 to 1998 balances to reflect this one month lag.

## Measurement and Evaluation Results

Attached are brief descriptions of measurement and evaluation (M&E) efforts that have occurred during the course of the trimester. Additional work has been done within this area, the results of which will be presented at the Spring / Summer 2001 Triple-E meeting.

It should be noted that Avista is reducing the M&E resources that will be devoted to providing independent testing of unproven energy efficiency devices. Based upon our experience it is more appropriate to rely on other independent third-party laboratories to provide this type of testing. This change in emphasis does not extend to measuring the energy impact of commercially available and proven energy efficiency devices claimed as part of our program portfolio.

### Resource Management Partnership Program (RMPP)

Resource managers assigned to participating school districts initiate and maintain behavioral, operational and hardwired energy efficiency measures at facilities throughout the school district.

Energy savings claims from the RMPP program are based upon comparisons of actual comprehensive meter reads from all meters of each participating school district. Provisions have been made to appropriately measure and claim re-adoption of the short lifespan behavioral and operational measures. The methodology adopted for the measurement of re-adoption is consistent with the calculation of the weighted average lifespan of the energy savings claimed from this program. (The weighted average energy savings in this category is only four years).

Hardwired measures that are installed in facilities participating in the RMPP program are claimed in the specific technology category involved rather than as part of the resource management technology.

Energy savings from this program have been gradually declining over time as the most cost-effective measures are acquired. During this trimester only 62,007 annual kWh were claimed in the Government segment under the resource management technology. As previously mentioned, this does not include the acquisition of substantial hardwired lighting efficiency measures, as those savings accrue to the lighting technology.

### VendingMISER™

As indicated in the last trimester report, Avista is continuing a long-term evaluation of the VendingMISER™ vending machine control device. At present Avista is claiming 1500 annual kWh per device. This amount was based upon manufacturer data, independent tests and further tests completed by Avista.

Based upon M&E completed to date it appears that the actual savings of devices installed by Avista is closer to the range of 1,000 to 1,200 kWh per year.

Due to the substantial variance in the savings from device to device this M&E project will continue into at least the next trimester before the past and future energy savings claims are corrected.

Additionally, Avista has expanded the M&E effort to attempt to identify other potential factors in determining the energy savings on installed devices. Specifically, we are interested in determining if the newer machines achieve greater energy savings as a result of their larger physical size and increased panel illumination. Past measurements by Avista have not consistently recorded machine size, type or vintage.

Individual project reviewsCity of Coeur d'Alene LED Traffic Lights Measurement & Evaluation Report

## Methodology:

A complete intersection-by-intersection inspection to verify what was actually installed.

Savings were determined utilizing readings from the existing kWh meter before and after installation. Calculated estimates were used for one new intersection, Hanley and Ramsey.

## Findings:

Light Count Error: The initial report shows 16 through lanes at Government and Ironwood, but there are only 13 through lanes. This error is relatively insignificant, resulting in an overstatement of savings projections by 1,700 kWh (about 1%.)

Run Time Assumptions: Conservative run times were used for the original estimates. As a result, savings projections in the Avista Service Territory were 15% below actual results (28,000 kWh).

Exclusion of Kootenai Electric Intersections: No savings were ever claimed for the three intersections in Kootenai Electric Service Territory. The savings for the three Kootenai Electric Intersections is 50,000 kWh.

Winter Peaking Phenomenon: Five downtown intersections exhibited an unexpected "winter peaking" phenomenon. Results are shown below:

<b>Intersection</b>	<b>Typical Summer Usage</b>	<b>Winter Peak</b>
Second/Third and Sherman	800 kWh	5000 kWh
Fourth/Fifth and Sherman	400 kWh	3600 kWh
Seventh and Sherman	760 kwh	2400 kWh

Initial assumptions were that the increased usage was the result of (possibly unnecessary) cabinet heaters. Upon further investigation with the City's Signal Supervisor it was determined that these cabinet heaters have not been in use. The City Signal Supervisor is well aware that cabinet heaters are not needed with modern controls. As a result, heaters have not been used for many years.

The City was also surprised by the winter peaking phenomenon, and decided to investigate. It was learned that the winter peak is the result of extensive use of Christmas lighting in the downtown area. The Coeur d'Alene City Accounting Department is aware of the increased winter usage, and budgets accordingly.

Conclusion: *The savings should be adjusted upward from 144,000 kWh to 222,000 kWh. This adjustment will be made in the 8/1/00 to 12/31/00 report.*

GlobalTech™

GlobalTech™ is a device permitting the reduction in energy use of lighting systems at specific times of the day. Avista has worked with two outdoor area lighting demonstration projects within the service territory. Data is being collected regarding reductions in energy use, reductions in light output and overall effect upon the end-use.

The technology employed in the GlobalTech™ device will transition from being incentivized under the New Technology incentive tier to the standard high-efficiency incentive tier in January of 2001. This transition to standard efficiency incentives is based upon the amount of time that has elapsed since the project became commercially available in our area.

## Notable Projects, Disclosures, and Policy Updates

Avista is presenting to the Triple-E Board written revisions of two major implementation policy areas. The first of these, the New Technology Policy Statement, is a material revision to our past approach in this area. The second policy statement, regarding the calculation of customer simple paybacks, is a collection of minor revisions to a previous written policy.

It is our intent to commit other policies to writing over the remainder of 2000 and the early portion of 2001. Each of these will be revised as necessary and appropriate, and significant revisions will become part of future Triple-E Reports.

### New Technology Policy Statement

Avista has committed to writing policies regarding the granting and management of projects receiving enhanced incentives under the New Technology portion of the Schedule 90 incentive structure.

The policy is subject to revision on an as-necessary basis. Interpretation of the policy and management of the projects fall primarily to the Program Manager for that particular Customer Segment.

The most current policy statement is included below in its entirety:

### **Avista Utilities Customer Solutions Department Policy on the Granting of New Technology Incentive Status**

#### **Overview**

The Avista Utilities Schedule 90 identifies three tiered categories of incentives available to customers for energy-efficiency projects. These tiers are (1) high-efficiency incentives, (2) new technology incentives and (3) fuel-efficiency (electric to natural gas conversion) incentives. While the third category, fuel-efficiency incentives, is very distinct from the other two categories, there is much more opportunity for confusion regarding the applicability of the high-efficiency and new technology incentive levels.

Similarly Avista is proposing a Schedule 190 natural gas efficiency tariff with both high-efficiency and new technology incentives. These two incentive structures share the same indistinct relationship as has been found in the electric Schedule 90 tariff.

In both the electric and gas efficiency tariffs the new technology incentives exceed the high-efficiency incentive levels by a substantial 50% to 100%.

This general policy statement is being created in order to ensure that these enhanced incentives are applied in a non-discriminatory manner and to increase their effectiveness by targeting them for the appropriate technology applications.

#### **Policy Statement**

The intent of the enhanced new technology incentive structure is to provide the flexibility for Avista to overcome known and identifiable market barriers for appropriate and cost-effective applications of energy-efficiency with a temporary and targeted application of premium customer incentives on either a case-by-case or on a prescriptive basis. The end result must be the acquisition of long-term energy savings either from increased penetration of an energy-efficiency measure or through the accelerated adoption of the measure. It is well known that not all market barriers can be addressed by an enhanced incentive, and the enhanced incentive structure is not intended to be the sole mechanism for addressing all market barriers.

The reference to “known and identifiable market barriers” requires that the request for new technology status be accompanied by a satisfactory identification of this market barrier. This may include, but is not necessarily limited to:

- A lack of confidence on the part of the customer as to how it will effect their operation. This is only a market barrier if there are significant energy savings achievable within the Avista service territory that would benefit from such a demonstration project. The wholesale and/or retail infrastructure is undeveloped or underdeveloped in a way that reduces or delays the penetration of the energy-efficiency measure.
- A degree of saturation required to promote the incorporation of a particular measure into an energy code or the promotion of the measure as the industry standard.
- A lack of confidence regarding the energy efficiency or the non-energy impact of the measure.

The application must also be “appropriate”. This means that:

- The measure may not have non-energy disbenefits that are so substantial as to make the measure non-viable from the standpoint of an informed and rational consumer. This is particularly true in a case where the non-energy disbenefits are related to safety.
- The measure must be the best-available energy practice available regardless of fuel. Under no circumstances will Avista provide enhanced new technology incentives for measures that are not the best available option for the customer.

Measures incentivized under the new technology structure must also be “cost-effective”. Cost-effective will be defined as:

- Having a cost-effectiveness substantially above 1.0 using the Total Resource Cost test as calculated in Avista’s periodic reporting methodology.
- This calculation does include quantifiable non-energy benefits. The decision on the inclusion of non-quantifiable non-energy benefits will be made on a case-by-case basis.

The enhanced incentives must be “temporary”. This means that:

- There must be a well-established and sound business plan indicating that the market barrier identified will be addressed by the enhanced incentives within a finite period of time. This period of time should not exceed two years in most cases, with shorter periods preferred to longer periods due to the inherent risk in the longer term.
- Quantifiable market indicators must be identified that will track the success, or lack thereof, of the enhanced incentives in addressing the market barrier. Non-quantifiable indicators are acceptable, but a clear definition is an absolute requirement.
- The term over which new technology incentives are granted must be consistent with the business plan for overcoming the market barrier as well as ensuring equitable treatment to customers.

The application of the new technology incentive must be “targeted”:



- Enhanced incentives will only be applied as part of a business plan for addressing the market barrier. The business plan selected must be the best available for addressing that technology application. The field of "best available" is not confined to options that are available through Schedule 90 or 190 only. Other options may include multi-utility approaches, regional or national approaches or other options that may or may not include utilities at all.
- Whenever applicable, the new technology approach must coordinate with other utility or non-utility initiatives in the same field.

#### Procedure

Adherence to quality business planning and decision-making is of great importance in the proper application of the new technology incentive alternative. Strict adherence to a particular procedure is much less important.

It is well recognized that concepts for new technology applications will be, and should be, discussed widely and informally. This is to be encouraged as a means of both generating and improving successful new technology applications.

As the concept becomes increasingly firm, it is necessary to work closely with all DSM portfolio managers to ensure that the application is coordinated with their offerings. At this stage mutually exclusive concepts and concepts that for any reason do not fit within the portfolio should be identified. The discussion of timing of the launch and coordination would also be initially discussed with the portfolio manager.

When the concept becomes reasonably firm the Partnership Solutions Team would become involved. At this later stage the business plan concept would be trued up to the new technologies policy. Upon conclusion a brief business plan and future checkpoints would be established for each new technology. Those responsible for following -through with the implementation and the checkpoints would also be clearly identified.

#### Summary

This approach is intended to provide a basis for systematically evaluating new technology concepts. The process will be periodically reevaluated to determine if it meets the needs of the Company's energy-efficiency effort. The best expected measure of success would be to:

- improve the quality of concepts that are launched either through the new technologies option or through alternative approaches to the market issue(s).
- eliminate or suspend those concepts that are, for any reason, inappropriate for the new technologies treatment .
- provide a basis for continuous improvement of our process through learning about how to better approach these identified market opportunities.

#### Sample New Technologies Business Plan

LED Traffic Lights

#### Market Barrier:

- An emerging technology.
- There are bureaucratic and legal issues with being the first adopted, particularly among smaller traffic entities.

- The life of the units are unknown and potentially variable (due to UV degradation).
- Red-light runtime is unknown.
- Capital cost of yellow and green lights are significantly above red lights (but red-light only installations are available).
- Sufficient number of manufacturers, but none within our service territory.

Appropriateness:

- Due to the slow degradation instead of catastrophic failure, there is a non-energy safety benefit.
- There are also reduced costs (and increased safety) due to the reduction in the number of incandescent lamp changes required.

Cost-effectiveness:

- Red-lights are cost-effective (reference attached cost-effectiveness analysis).
- Green lights and yellow lights are not cost-effective at this time.

Timeline:

- New technology incentives guaranteed for one year and reevaluated at that point.

Targeting:

- Target the larger traffic entities within our service territory on the belief that smaller entities will follow-suit. Target customers are City of Spokane, County of Spokane, and City of Coeur d'Alene.
- Include substantial M&E (runtime, degradation of light) in the early period in order to represent these figures to other entities.

Summary:

- Use enhanced incentives and limited-time-offer to obtain significant penetration of the early adopter segment.
- Discontinue incentive with appropriate (e.g. 3 month) notice once we have the following:
  - 1) A solid adoption (e.g. two of the three identified) in the early adopter segment.
  - 2) A significant start in the smaller segment (e.g. 3 entities)
  - 3) At least one manufacturer marketing the product to customers within our service territory.

Additionally:

- Coordinate implementation with any developing RCM program in the governmental segment.
- Long-term bonus: Challenge the industry standard of three to four lights per intersection. Can this be reduced by one light (down to a minimum of two) as a result of the lack of catastrophic failure in LEDs? This would substantially reduce the capital cost of converting over to LEDs.
- Coordinate with WA General Administration or our own internal financing / leasing program.

Simple Payback Policy Statement

Schedule 90 prescribes three separate incentive approaches to electric efficiency projects; (1) electric efficiency, (2) new technology and (3) fuel-conversion. The definitions and tier structures of each of these three categories are as follows:

Electric efficiency: These are projects which exceed code-minimum or industry standard but are not electric to gas conversions or granted new technology status. Incentives are:

- 8 cents per first-year kWh for projects with simple paybacks in excess of 72 months
- 6 cents per first-year kWh for projects with simple paybacks between 48 and 72 months
- 4 cents per first-year kWh for projects with simple paybacks between 18 and 48 months
- No customer direct monetary incentives are granted for projects with paybacks under 18 months

New Technology: These are projects granted new technology status per the standards outlined in the preceding New Technology policy. Incentives for the savings directly attributable to the project (excluding any market transformation effect) are:

- 14 cents per first-year kWh for projects with simple paybacks in excess of 72 months
- 12 cents per first-year kWh for projects with simple paybacks between 48 and 72 months
- 10 cents per first-year kWh for projects with simple paybacks less than 48 months

Fuel-Conversion: Projects involving the conversion of an end-use from electric to natural gas. Projects must be served by Avista electricity, but need not be served by Avista natural gas. The entire reduction in electric kWh load is applied to the incentives below:

- 3 cents per first-year kWh for projects with simple paybacks in excess of 72 months
- 2 cents per first-year kWh for projects with simple paybacks between 48 and 72 months
- 1 cents per first-year kWh for projects with simple paybacks between 24 and 48 months
- No customer direct monetary incentives are granted for projects with paybacks under 24 months

Because the tiered structure of each of these three categories is based upon the projects simple payback, it was necessary to develop a written standard for the calculation of simple payback. The standardization of the calculation promotes consistent calculations in full compliance with Schedule 90. In addition to the written policy, a spreadsheet model was developed to perform the calculations.

The process of incentive calculation also incorporates the collection of additional project data for use in cost-effectiveness calculations.

The most current written policy on simple-payback calculations is attached below.

#### **Standards for the Calculation of Customer Simple Paybacks for Application to Schedule 90 Incentives**

##### Non-Energy Benefits

- Data regarding non-energy benefits is to be collected by the technical project lead and by the account executive with the entry into SalesLogix being the account executive's responsibility.
- Non-energy benefit data will be incorporated into cost-effectiveness calculations by Partnership Solutions.
- Non-energy benefits are not to be included in the calculation of simple payback for purposes of determining the customer's incentive.

Simple Payback (used for Direct Incentives)

- Simple payback is the customer cost, as defined within this policy, divided by the first year electric bill savings accruing to the customer. The incentive level will then be determined by applying that simple payback to the tier structure defined in Schedule 90.
- Data collection will be the joint responsibility of the technical lead and the account executive. Coordination and entry of the data into SalesLogix will be the account executive's responsibility.
- The account executive is responsible for submitting the data to Partnership Solutions for calculation of simple payback before the evaluation is submitted to the customer.
- Partnership Solutions will return to the account executive the final results of the incentive calculation.
- Capital cost estimates can be arrived at in many ways (e.g. Means Mechanical Estimating, contractor bids, industry standards, and in-house analysis).
- Simple payback calculations are not to include the values of non-energy benefits.
- The simple payback calculation will not include adjustments for interactive non-electric energy effects (e.g. the impact of a lighting retrofit on natural gas HVAC systems).
- The calculation will include adjustments for interactive electric energy effects (e.g. the impact of a lighting retrofit on electric HVAC systems).
- The calculation will include those non-electric effects that are a direct consequence of the project (e.g. the increase in therms as a result of an electric to natural gas conversion).
- Calculation is to include all values for electric energy savings, kWh, kW, kVAR.
- The calculation will include the bill savings resulting from kWh, kW and kVAR impacts of the project, plus any associated electric bill tax or fee impacts.
- Similar measures (e.g., lighting and lighting controls or HVAC and HVAC controls) can be bundled for calculations, but dissimilar measures (e.g., lighting and VFDs) must be treated as separate projects.
- Sales tax paid by the customer and associated with the energy efficiency portion of the will be included as a cost for the simple payback calculation.

Calculation of Customer Cost (used for Direct Incentives)

- The customer costs to be included in the simple payback calculation will be only those associated with the energy-efficiency portion of the project relative to a defined baseline. Energy savings will be calculated based upon the same definition of the baseline and high-efficiency project.
- The calculation of customer costs will not include any deductions for non-energy benefits, but the baseline and high-efficiency projects will be defined to exclude these costs and benefits to the extent possible.
- Any direct or indirect incentive received by the customer will not be used to reduce the customer cost for purposes of the calculation of simple payback.
- The installation of used equipment does qualify for direct incentives, assuming that the equipment meets all other standards.
- The appropriate basecase for projects where existing equipment is in imminent failure is the equivalent code minimum or industry standard, whichever is more energy efficient. Imminent failure is defined as equipment that is likely to fail within the next year and is likely to be replaced with new equipment.
- The appropriate basecase for new construction or substantial renovation is also the code minimum or industry standard, whichever is more energy efficient.

Calculation of Customer Costs (used for Cost-Effectiveness)

- The calculation of customer cost for inclusion in cost-effectiveness calculations will include only those costs associated with the energy-efficiency portion of the project.

Energy savings will be calculated based upon the same definition of the baseline and high-efficiency project.

- The customer cost will be adjusted as necessary to compensate for significant differences in the physical life of the basecase and the high-efficiency scenarios.
- The customer costs will not include adjustments for non-energy benefits, although non-energy benefits are to be tracked for inclusion in cost-effectiveness calculations.
- The customer costs included in cost-effectiveness calculations will not include adjustments for customer direct or indirect incentives.

#### Qualifying Projects

- Projects that are characterized by having a significant degradation of end-use quality do not qualify for either customer incentives or for credit toward energy savings calculations. Degradation of savings is defined as a significant reduction to the value, comfort, convenience or other attributes of an end-use. Any non-trivial reduction in the safety of any end-use will disqualify the project. This will apply to both residential and non-residential projects.

For example, degradation of end-use would disqualify projects such as:

- A lighting retrofit that reduces the lighting level below industry standards.
- Changes in HVAC temperature settings which are not associated with any other efficiency project.
- Reductions in lighting levels which are deemed to adversely effect safety.
- The closure or destruction of a facility.

Examples of projects which are not disqualified due to degradation of end-use include:

- Reductions in lighting levels which do not adversely effect comfort, safety or any other end-use attribute.
- Changes in HVAC temperatures when facilities are unoccupied or changes in a manner which do not adversely effect comfort or any other end-use attribute.
- Changes in an industrial process which reduces the energy use without effecting the quantity or quality of the product.
- Changes in facility operating hours which do not materially effect the business value of the facility.

## Appendix A

### Summarization of the Last Twelve Months of Activity

#### Detail Summary of Cost-Effectiveness Results

Overall the programs are cost-effective per the following:

- TRC Test (1.17 benefit/cost (B/C) ratio, \$1.9 million of net societal benefits)
- UC Test (1.49 B/C ratio, \$3.1 million of net utility benefits)
- Participant Test (4.11 B/C ratio, \$15.6 million in net benefits)

In summary, the program portfolio is a cost-effective resource, both societally and to the utility, and the programs have very strongly benefited participating customers.

This analysis has been completed using the avoided costs identified in the Company's most recent electric and gas Integrated Resource Plans. Since those avoided costs are below the Company's rates (the difference being the non-commodity cost), it is mathematically impossible for the portfolio to pass the Non-Participant Test. This test has resulted in a 0.39 Non-participant test B/C ratio and a negative \$16.4 million in net non-participant benefits.

The interpretation of the Non-Participant Test (also known as the Rate Impact Measure) is to determine the upward pressure on rates imposed by the energy-efficiency programs. It is notable that upward rate pressure does not necessarily result in increased energy bills (even including participant costs) due to the decreased consumption resulting from these programs.

Having a full three trimesters of data, we can now begin to tentatively determine some trends in the cost-effectiveness results. The TRC Test results seem to be fairly stable, probably because it is a fairly broadly-based test. There is a slight but persistent upward trend in the cost-effectiveness.

The Utility Cost Test and the Participant Test seem substantially more variable. The decreased UCT ratio and increased Participant Cost Test ratio in the 2<sup>nd</sup> trimester is notable. Investigation indicates that this is attributable to unusually high investments in durable equipment and infrastructure made during this time period.

The Participant Test is well below one, for the reasons previously explained, and fairly stable at that level.

Refer to *Table A1* for the results of each of the last three trimesters followed by the overall cost-effectiveness of the entire year. The trimester results are also graphically represented in *Chart A2*.

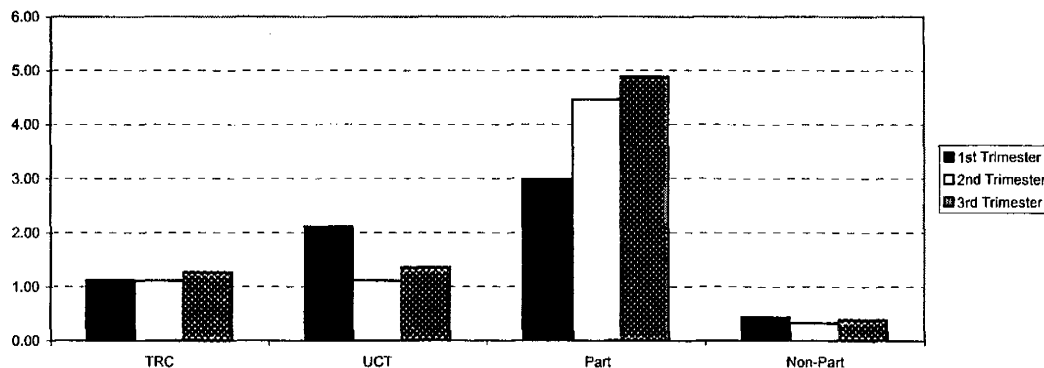
Table A1

Avista Electric-Efficiency Program Twelve-Month Summary

	Aug. 1 '99 to Nov. 30 '99 (4 months)			Dec. 1 '99 to Mar. 30 '00 (4 months)			Apr. 1 '00 to Jul. 31 '00 (4 months)			Aug. 1 '99 to Jul. 31 '00 (12 months)		
	Reg. Inc.	Lm. Inc.	Portfolio	Reg. Inc.	Lm. Inc.	Portfolio	Reg. Inc.	Lm. Inc.	Portfolio	Reg. Inc.	Lm. Inc.	Portfolio
<b>Total Resource Cost Test</b>												
Electric Avoided Cost	\$ 4,303,697	\$ 457,790	\$ 4,761,487	\$ 2,066,877	\$ 599,880	\$ 2,666,757	\$ 3,266,327	\$ 532,751	\$ 3,799,078	\$ 9,636,901	\$ 1,590,421	\$ 11,227,322
Non-energy benefits	\$ 76,850	\$ -	\$ 76,850	\$ 1,775,461	\$ -	\$ 1,775,461	\$ 2,001,662	\$ -	\$ 2,001,662	\$ 3,853,973	\$ -	\$ 3,853,973
Gas Avoided Cost	\$ (859,424)	\$ (63,443)	\$ (922,867)	\$ (209,832)	\$ (136,413)	\$ (346,245)	\$ (288,016)	\$ (353,470)	\$ (641,486)	\$ (1,357,272)	\$ (553,326)	\$ (1,910,598)
<b>TOTAL TRC BENEFITS</b>	<b>\$ 3,521,123</b>	<b>\$ 394,347</b>	<b>\$ 3,915,470</b>	<b>\$ 3,632,506</b>	<b>\$ 463,467</b>	<b>\$ 4,095,973</b>	<b>\$ 4,978,973</b>	<b>\$ 179,281</b>	<b>\$ 5,159,254</b>	<b>\$ 12,133,602</b>	<b>\$ 1,037,095</b>	<b>\$ 13,170,697</b>
Non-Incentive Utility Cost	\$ 905,457	\$ 29,569	\$ 935,026	\$ 1,080,782	\$ 95,227	\$ 1,176,009	\$ 1,083,832	\$ 45,632	\$ 1,129,464	\$ 3,070,071	\$ 170,428	\$ 3,240,499
Customer Cost	\$ 2,273,339	\$ 291,377	\$ 2,564,716	\$ 2,103,311	\$ 414,492	\$ 2,517,803	\$ 2,572,199	\$ 365,504	\$ 2,937,703	\$ 6,948,849	\$ 1,071,373	\$ 8,020,222
<b>TOTAL TRC COSTS</b>	<b>\$ 3,178,796</b>	<b>\$ 320,946</b>	<b>\$ 3,499,742</b>	<b>\$ 3,184,093</b>	<b>\$ 509,719</b>	<b>\$ 3,693,812</b>	<b>\$ 3,656,031</b>	<b>\$ 411,136</b>	<b>\$ 4,067,167</b>	<b>\$ 10,018,920</b>	<b>\$ 1,241,801</b>	<b>\$ 11,260,721</b>
TRC B/C Ratio	1.11	1.23	1.12	1.14	0.91	1.11	1.36	0.44	1.27	1.21	0.84	1.17
Net TRC benefits	\$ 342,327	\$ 73,401	\$ 415,728	\$ 448,413	\$ (46,252)	\$ 402,161	\$ 1,323,942	\$ (231,855)	\$ 1,092,087	\$ 2,114,682	\$ (204,706)	\$ 1,909,976
<b>Utility Cost Test</b>												
Electric Avoided Cost	\$ 4,303,697	\$ 457,790	\$ 4,761,487	\$ 2,066,877	\$ 599,880	\$ 2,666,757	\$ 3,266,327	\$ 532,751	\$ 3,799,078	\$ 9,636,901	\$ 1,590,421	\$ 11,227,322
Gas Avoided Cost	\$ (859,424)	\$ (63,443)	\$ (922,867)	\$ (209,832)	\$ (136,413)	\$ (346,245)	\$ (288,016)	\$ (353,470)	\$ (641,486)	\$ (1,357,272)	\$ (553,326)	\$ (1,910,598)
<b>TOTAL UTC BENEFITS</b>	<b>\$ 3,444,273</b>	<b>\$ 394,347</b>	<b>\$ 3,838,620</b>	<b>\$ 1,857,045</b>	<b>\$ 463,467</b>	<b>\$ 2,320,512</b>	<b>\$ 2,978,311</b>	<b>\$ 179,281</b>	<b>\$ 3,157,592</b>	<b>\$ 8,279,629</b>	<b>\$ 1,037,095</b>	<b>\$ 9,316,724</b>
Non-Incentive Utility Cost	\$ 905,457	\$ 29,569	\$ 935,026	\$ 1,080,782	\$ 95,227	\$ 1,176,009	\$ 1,083,832	\$ 45,632	\$ 1,129,464	\$ 3,070,071	\$ 170,428	\$ 3,240,499
Incentive Utility Cost	\$ 595,293	\$ 291,377	\$ 886,670	\$ 506,209	\$ 414,492	\$ 920,701	\$ 824,057	\$ 365,504	\$ 1,189,561	\$ 1,925,559	\$ 1,071,373	\$ 2,996,932
<b>TOTAL UTC COSTS</b>	<b>\$ 1,500,750</b>	<b>\$ 320,946</b>	<b>\$ 1,821,696</b>	<b>\$ 1,586,991</b>	<b>\$ 509,719</b>	<b>\$ 2,096,710</b>	<b>\$ 1,907,889</b>	<b>\$ 411,136</b>	<b>\$ 2,319,025</b>	<b>\$ 4,995,630</b>	<b>\$ 1,241,801</b>	<b>\$ 6,237,431</b>
UCT B/C Ratio	2.30	1.23	2.11	1.17	0.91	1.11	1.56	0.44	1.36	1.66	0.84	1.49
Net UCT benefits	\$ 1,943,523	\$ 73,401	\$ 2,016,924	\$ 270,054	\$ (46,252)	\$ 223,802	\$ 1,070,422	\$ (231,855)	\$ 838,567	\$ 3,283,999	\$ (204,706)	\$ 3,079,293
<b>Participant Test</b>												
Bill svgs	\$ 4,471,020	\$ 456,505	\$ 4,927,525	\$ 4,067,573	\$ 1,276,036	\$ 5,343,609	\$ 5,679,957	\$ 858,269	\$ 6,538,226	\$ 14,218,550	\$ 2,590,810	\$ 16,809,360
Non-energy benefits	\$ 76,850	\$ -	\$ 76,850	\$ 1,775,461	\$ -	\$ 1,775,461	\$ 2,001,662	\$ -	\$ 2,001,662	\$ 3,853,973	\$ -	\$ 3,853,973
<b>TOTAL PART. BENEFITS</b>	<b>\$ 4,547,870</b>	<b>\$ 456,505</b>	<b>\$ 5,004,375</b>	<b>\$ 5,843,034</b>	<b>\$ 1,276,036</b>	<b>\$ 7,119,070</b>	<b>\$ 7,681,619</b>	<b>\$ 858,269</b>	<b>\$ 8,539,888</b>	<b>\$ 18,072,523</b>	<b>\$ 2,590,810</b>	<b>\$ 20,663,333</b>
Customer Cost	\$ 2,273,339	\$ 291,377	\$ 2,564,716	\$ 2,103,311	\$ 414,492	\$ 2,517,803	\$ 2,572,199	\$ 365,504	\$ 2,937,703	\$ 6,948,849	\$ 1,071,373	\$ 8,020,222
Incentive Utility Cost	\$ (595,293)	\$ (291,377)	\$ (886,670)	\$ (506,209)	\$ (414,492)	\$ (920,701)	\$ (824,057)	\$ (365,504)	\$ (1,189,561)	\$ (1,925,559)	\$ (1,071,373)	\$ (2,996,932)
<b>TOTAL PART. COSTS</b>	<b>\$ 1,678,046</b>	<b>\$ -</b>	<b>\$ 1,678,046</b>	<b>\$ 1,597,102</b>	<b>\$ -</b>	<b>\$ 1,597,102</b>	<b>\$ 1,748,142</b>	<b>\$ -</b>	<b>\$ 1,748,142</b>	<b>\$ 5,023,290</b>	<b>\$ -</b>	<b>\$ 5,023,290</b>
Participant B/C Ratio	2.71	#DIV/0!	2.98	3.66	#DIV/0!	4.46	4.39	#DIV/0!	4.89	3.60	#DIV/0!	4.11
Participant net benefits	\$ 2,869,824	\$ 456,505	\$ 3,326,329	\$ 4,245,932	\$ 1,276,036	\$ 5,521,968	\$ 5,933,477	\$ 858,269	\$ 6,791,746	\$ 13,049,233	\$ 2,590,810	\$ 15,640,043
<b>Non-Participant (electric) Test</b>												
Electric Avoided Cost	\$ 3,444,273	\$ 394,347	\$ 3,838,620	\$ 2,066,877	\$ 599,880	\$ 2,666,757	\$ 3,266,327	\$ 532,751	\$ 3,799,078	\$ 8,777,477	\$ 1,526,978	\$ 10,304,455
<b>TOTAL NON-PART BENEFITS</b>	<b>\$ 3,444,273</b>	<b>\$ 394,347</b>	<b>\$ 3,838,620</b>	<b>\$ 2,066,877</b>	<b>\$ 599,880</b>	<b>\$ 2,666,757</b>	<b>\$ 3,266,327</b>	<b>\$ 532,751</b>	<b>\$ 3,799,078</b>	<b>\$ 8,777,477</b>	<b>\$ 1,526,978</b>	<b>\$ 10,304,455</b>
Revenue Loss	\$ 6,274,491	\$ 619,887	\$ 6,894,378	\$ 4,537,681	\$ 1,535,961	\$ 6,073,642	\$ 6,125,922	\$ 1,335,171	\$ 7,461,093	\$ 16,938,094	\$ 3,491,019	\$ 20,429,113
Non-Incentive Utility Cost	\$ 905,457	\$ 29,569	\$ 935,026	\$ 1,080,782	\$ 95,227	\$ 1,176,009	\$ 1,083,832	\$ 45,632	\$ 1,129,464	\$ 3,070,071	\$ 170,428	\$ 3,240,499
Incentive Utility Cost	\$ 595,293	\$ 291,377	\$ 886,670	\$ 506,209	\$ 414,492	\$ 920,701	\$ 824,057	\$ 365,504	\$ 1,189,561	\$ 1,925,559	\$ 1,071,373	\$ 2,996,932
<b>TOTAL NON-PART COSTS</b>	<b>\$ 7,775,241</b>	<b>\$ 940,833</b>	<b>\$ 8,716,074</b>	<b>\$ 6,124,672</b>	<b>\$ 2,045,680</b>	<b>\$ 8,170,352</b>	<b>\$ 8,033,811</b>	<b>\$ 1,746,307</b>	<b>\$ 9,780,118</b>	<b>\$ 21,933,724</b>	<b>\$ 4,732,820</b>	<b>\$ 26,666,544</b>
Non-Participant B/C ratio	0.44	0.42	0.44	0.34	0.29	0.33	0.41	0.31	0.39	0.40	0.32	0.39
Non-Participant net benefits	\$ (4,330,968)	\$ (546,486)	\$ (4,877,454)	\$ (4,057,795)	\$ (1,445,800)	\$ (5,503,595)	\$ (4,767,484)	\$ (1,213,556)	\$ (5,981,040)	\$ (13,156,247)	\$ (3,205,842)	\$ (16,362,089)

Chart A2

Standard Cost-Effectiveness Ratios by Trimester



Notably, at this point, 29% of the TRC benefits are derived from quantifiable non-energy benefits. If our ability to quantify those benefits increases we should see significant movement in this relationship, as well as an increase in the TRC ratio.

The results of the TRC test are, to a significant degree, not immediately within the control of the utility. 71% of the TRC costs are customer costs, with the remaining 29% being non-incentive utility costs.

The utility costs are fairly evenly split between incentive and non-incentive costs. The proportion of utility costs going towards incentives has increased with the adoption of the generally higher tiered incentives in the most recent revision of Schedule 90.

Refer to *Charts A3 – A5* for TRC Test benefits and costs, and Utility Cost Test costs.



Chart A3

TRC Costs

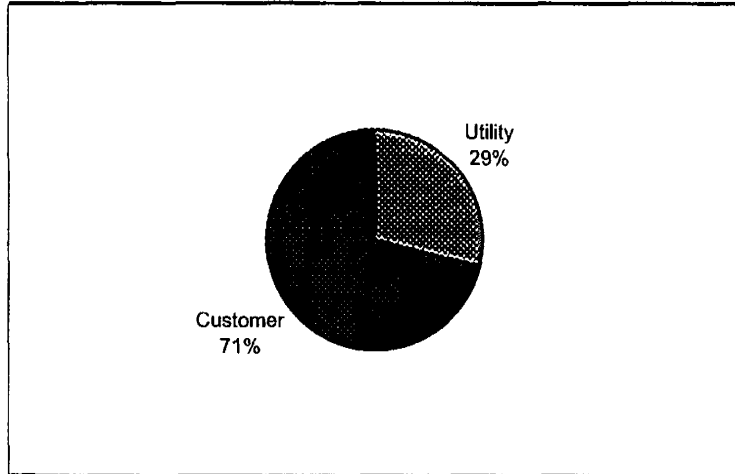


Chart A4

TRC Benefits

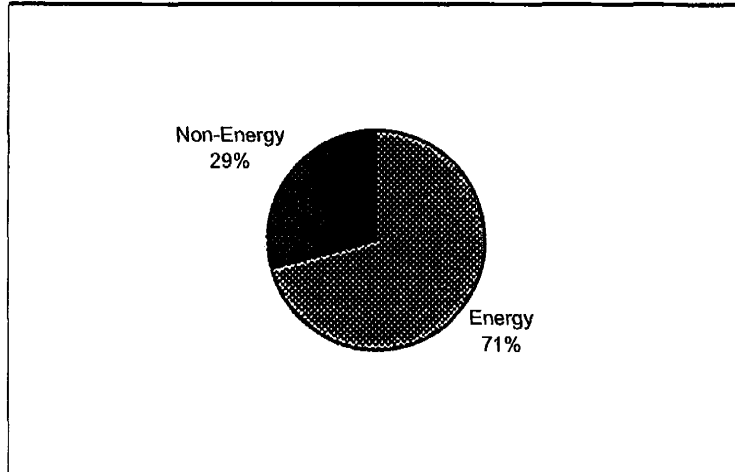
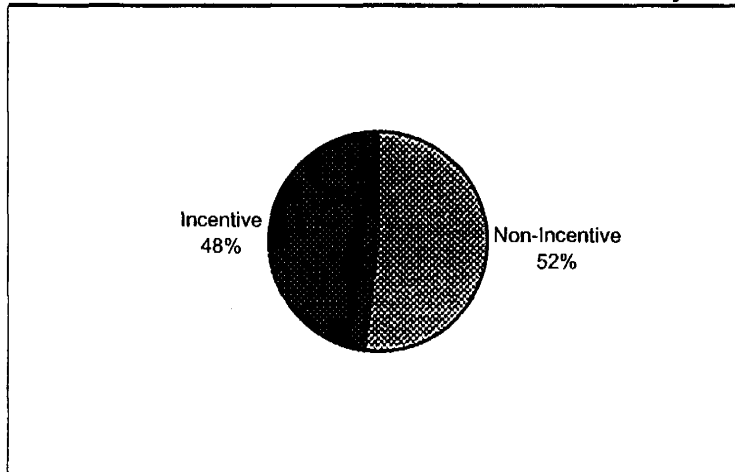


Chart A5

Utility Costs



The energy-efficiency programs have saved over 43 million 1<sup>st</sup> year kWh's (nearly 5 amW's) in the last twelve months.

The most recent trimester has been the highest energy savings period to date. However, given only three trimesters it is difficult to call this an identifiable trend.

The energy savings are most concentrated in the Government segment. This is undoubtedly attributable to Avista's highly successful Resource Management Partnership Program (RMPP). The savings from that program are generally declining as the most cost-effective measures are gradually being adopted within the participating school districts.

To put the success of the Government segment into perspective, the energy savings within this segment during this twelve-month period exceed the savings achieved in the Regular-Income and Limited-Income residential segments combined. This is not an indication of a lack of residential energy savings (these two segments are the fourth and fifth-ranking segments in terms of acquired energy). It is instead a measure of substantial first year kWh energy savings coming from RMPP.

The Office, Manufacturing and Residential segments are the next largest beneficiaries of energy savings. These savings are primarily attributable to lighting and HVAC savings in the medium to large office segment.

When energy savings are broken out by technology the HVAC segment is the largest contributor. This is somewhat misleading, given that much of these electrical savings come from electric to natural gas conversions. The calculation of electrical savings fails to fully realize the energy consumed on the natural gas portion of the conversion.

Lighting and controls are the next largest energy saving technologies. This can also be misleading since a significant proportion of the controls savings are attributable to lighting controls.

In the period of time covered by the second trimesterly report, there was some concern internally that there was too great of a reliance on "mass" projects (projects generally implementing measures with individually small savings but a large market). These include LED exit signs, LED traffic lights and VendingMI\$ER™. Additionally, lighting is a fairly routine measure that is often implemented in small quantities.

Analysis of the second and third trimester energy savings has indicated that 62% of savings are attributable to site-specific type projects. Most of the remainder (24%) comes from lighting projects. The LED exit sign and LED traffic light program savings have fallen substantially as those measures complete their aggressive marketing campaign under the enhanced New Technologies incentive structure. Future follow-ups to these measures are expected to demonstrate that these technologies have become much more accepted and perhaps even "industry standard" in CY 2001 and beyond.

While we have no particular baseline upon which to measure this program mix, it seems to be a reasonable diversification of the overall energy-efficiency portfolio.

Refer to *Charts A6 – A8* for electric savings broken down by trimester, segment, and technology.

Refer to *Chart A9* for the kWh breakdown by project type.

Chart A6 Electric Savings by Trimester

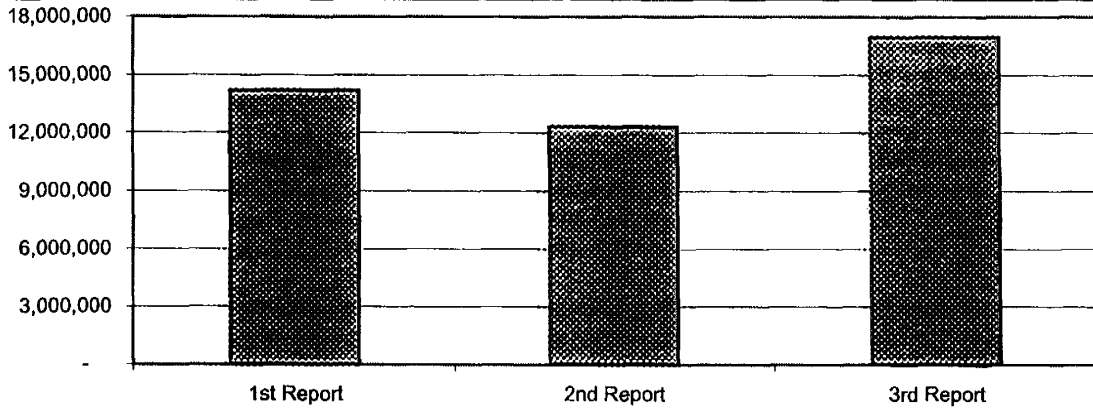


Chart A7 Electric Savings by Customer Segment

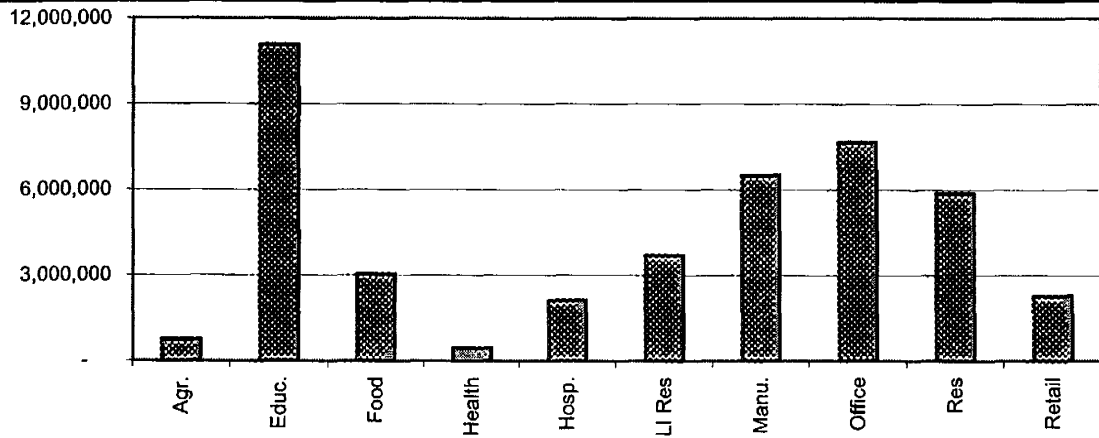


Chart A8 Electric Savings by Technology

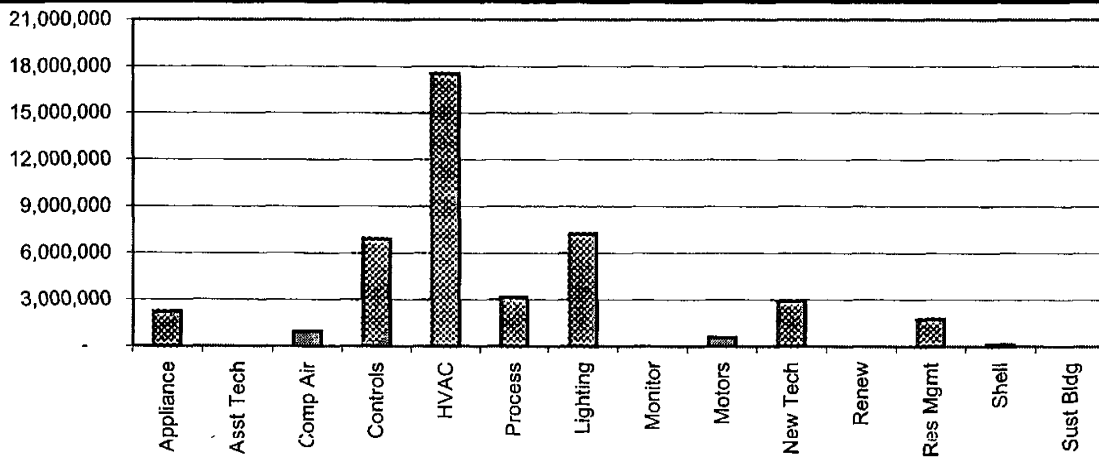
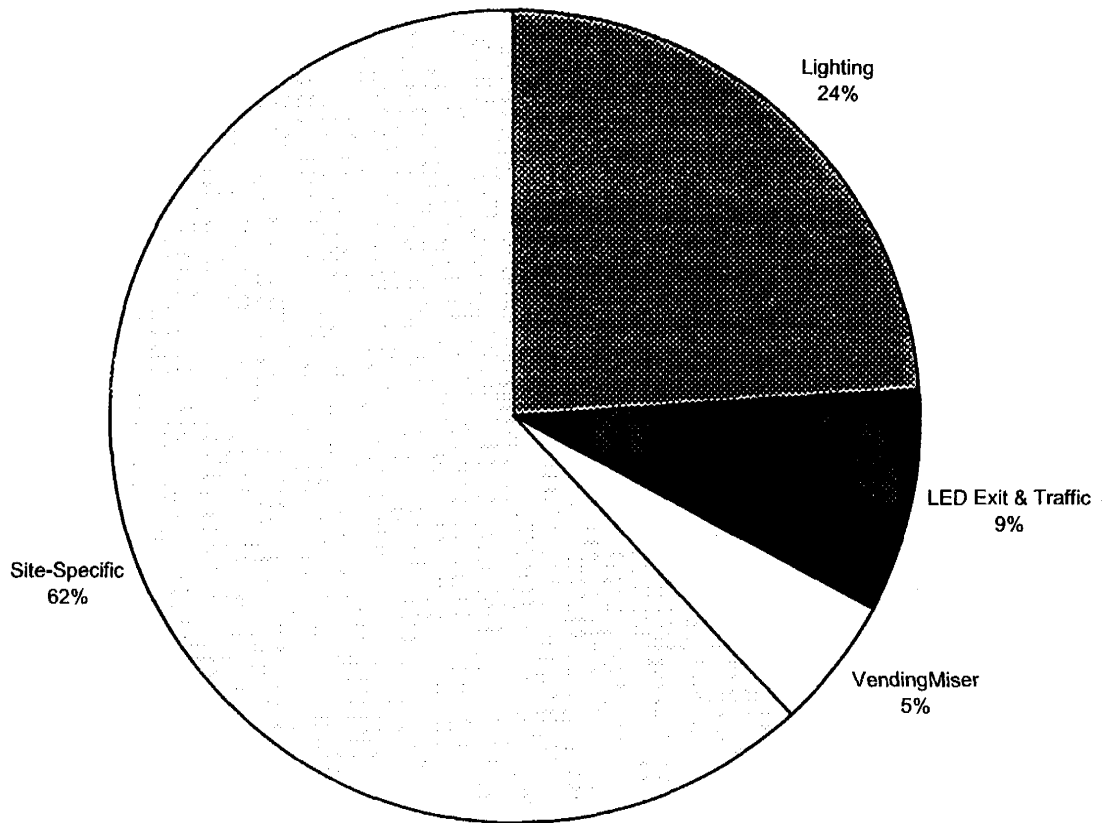


Chart A9

Project Breakdown by kWh (2nd and 3rd Reports)



The cost-effectiveness measurement of expenditures is persistently above the cash basis due to the increase in energy savings during this time period. More projects are coming into the pipeline (and being partially realized on an accrual basis for cost-effectiveness purposes) than are being completed (and being paid on a cash basis).

Refer to *Chart A10* for utility expenditures, calculated based upon both the cash basis and the cost-effectiveness basis.

The Energy-Efficiency Tariff Rider balance has also been captured for the entire system, as well as Washington and Idaho individually. Clearly the Idaho balance is very near zero and the Washington balance is falling dramatically. This tends to indicate that a change in the level of activity may be necessary in the summer of 2001, as well as the consideration of an increase in both Tariff Riders.

Refer to *Chart A11* for the Energy-Efficiency Tariff Rider balance in Washington, Idaho and system-wide.

Chart A10

Utility Cost (Cash Basis vs. Cost-Effectiveness Basis)

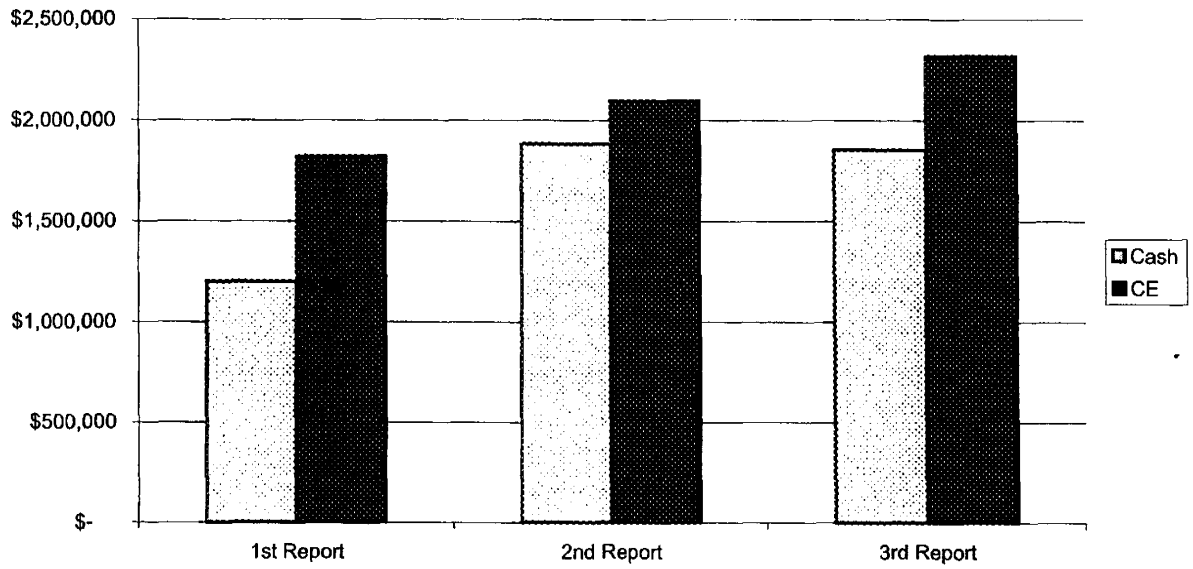
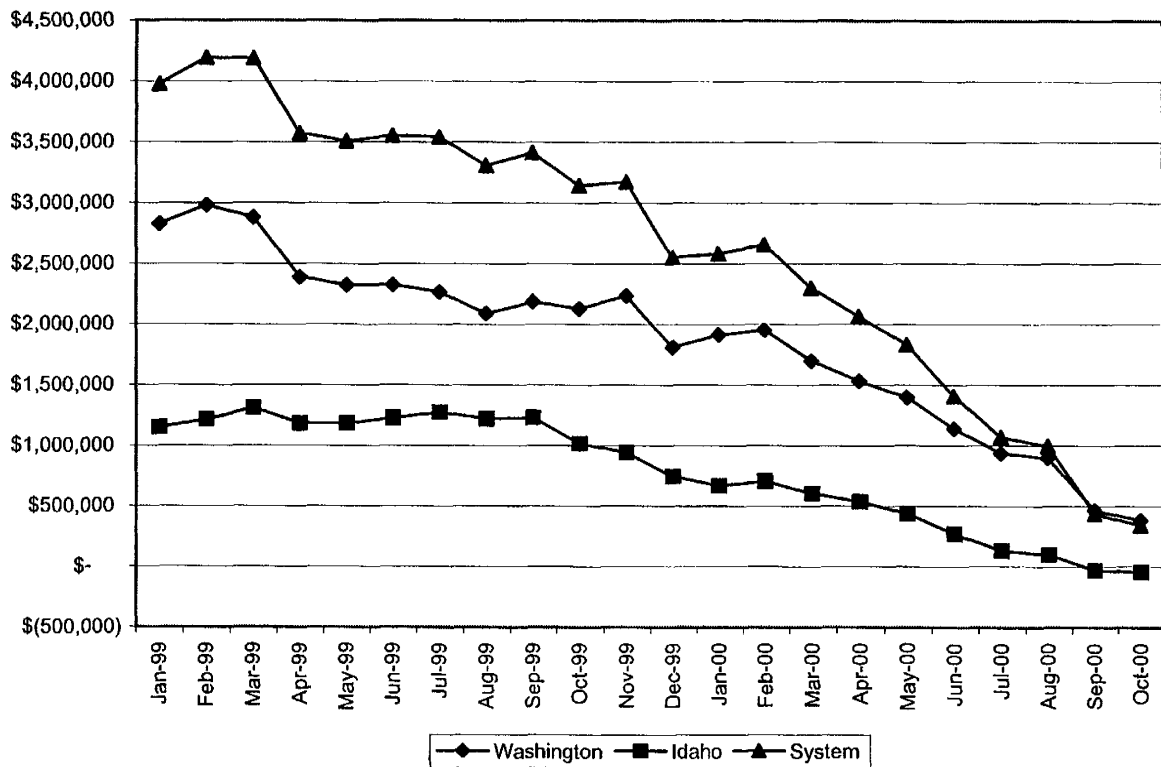


Chart A11

Energy-Efficiency Tariff Rider Balances



**Appendix B**  
**Additional Descriptive Statistics**

This Appendix updates the descriptive statistics contained in the previous Triple-E Report.

Refer to *Tables B1 and B2* for the quantity, energy savings and non-energy benefits of projects broken out by type.

Refer to *Tables B3 and B4* for a jurisdictional breakdown.

Refer to *Tables B5 and B6* for a breakdown of the number and energy savings of projects by electric rate schedule.

Refer to *Tables B7 and B8* for the same breakdown of therm savings by natural gas rate schedule.

Table B1

Breakdown of Database Projects by Type

Project Type	Project Count	% of Projects	kWh Savings	% of kWh	NEB \$/Yr	% of NEB \$/Yr
Lighting	78	21.0%	1,736,208	13.5%	\$ 29,690.50	49.8%
LED Exit Signs & Traffic Signals	27	7.3%	205,576	1.6%	\$ 20,916.41	35.1%
VendingMI\$ER	189	50.8%	750,750	5.9%	\$ 9,020.62	15.1%
Other	78	21.0%	10,129,704	79.0%	\$ (0.00)	0.0%
<b>All</b>	<b>372</b>	<b>100.0%</b>	<b>12,822,238</b>	<b>100.0%</b>	<b>\$ 59,627.52</b>	<b>100.0%</b>

Table B2

Breakdown of All Projects by Type

Project Type	Project Count	% of Projects	kWh Savings	% of kWh	NEB \$/Yr	% of NEB \$/Yr
Lighting	78	12.2%	1,736,208	10.2%	\$ 29,690.50	49.8%
LED Exit Signs & Traffic Signals	27	4.2%	205,576	1.2%	\$ 20,916.41	35.1%
VendingMI\$ER	189	29.6%	750,750	4.4%	\$ 9,020.62	15.1%
Limited Income	114	17.9%	1,738,035	10.3%	-	0.0%
Natural Gas Awareness	141	22.1%	2,251,028	13.3%	-	0.0%
RMPP	11	1.7%	62,007	0.4%	-	0.0%
Other	78	12.2%	10,208,591	60.2%	\$ (0.00)	0.0%
<b>All</b>	<b>638</b>	<b>100.0%</b>	<b>16,952,196</b>	<b>100.0%</b>	<b>\$ 59,627.52</b>	<b>100.0%</b>

Table B3

Breakdown of Database Projects by State

State	Project Count	% of Projects	kWh Savings	% of kWh
WA	173	46.5%	7,942,328	61.9%
ID	199	53.5%	4,879,911	38.1%
<b>All</b>	<b>372</b>	<b>100.0%</b>	<b>12,822,238</b>	<b>100.0%</b>

Table B4

Breakdown of All Projects by State

State	Project Count	% of Projects	kWh Savings	% of kWh
WA	363	56.8%	10,796,679	64.0%
ID	276	43.2%	6,076,629	36.0%
<b>All</b>	<b>638</b>	<b>100.0%</b>	<b>16,873,309</b>	<b>100.0%</b>



**Table B5 Breakdown of Database Projects by Electric Rate Schedule**

Rate Schedule	Project Count	% of Projects	kWh Savings	% of kWh
1	3	0.8%	2,375	0.0%
11	55	14.8%	224,254	1.7%
21	283	76.1%	6,933,467	54.1%
25	27	7.3%	5,265,770	41.1%
<i>Unknown</i>	4	1.1%	396,372	3.1%
<b>All</b>	<b>372</b>	<b>100.0%</b>	<b>12,822,238</b>	<b>100.0%</b>

**Table B6 Breakdown of All Projects by Electric Rate Schedule**

Rate Schedule	Project Count	% of Projects	kWh Savings	% of kWh
1	258	40.4%	3,991,438	23.7%
11	55	8.6%	224,254	1.3%
21	294	46.1%	6,995,474	41.5%
25	27	4.2%	5,265,770	31.2%
<i>Unknown</i>	4	0.6%	396,372	2.3%
<b>All</b>	<b>638</b>	<b>100.0%</b>	<b>16,873,309</b>	<b>100.0%</b>

**Table B7 Breakdown of Database Projects by Natural Gas Rate Schedule**

Rate Schedule	Project Count	% of Projects	Therm Savings	% of Therms
101	75	20.2%	19,507	43.0%
111	133	35.8%	28,617	63.1%
121	15	4.0%	1,275	2.8%
<i>None/Unknown</i>	149	40.1%	(4,021)	-8.9%
<b>All</b>	<b>372</b>	<b>100.0%</b>	<b>45,378</b>	<b>100.0%</b>

**Table B8 Breakdown of All Projects by Natural Gas Rate Schedule**

Rate Schedule	Project Count	% of Projects	Therm Savings	% of Therms
101	330	51.7%	(150,654)	90.9%
111	133	20.8%	28,617	-17.3%
121	26	4.1%	(39,763)	24.0%
<i>None/Unknown</i>	149	23.4%	(4,021)	2.4%
<b>All</b>	<b>638</b>	<b>100.0%</b>	<b>(165,821)</b>	<b>100.0%</b>



APPENDIX K

UPDATED LOADS AND  
RESOURCES

## UPDATED LOADS AND RESOURCES

Avista is continuously updating its position in regards to the balance between requirements (loads and sales) and its resources (generation and purchases). This is done on a day to day, month to month basis in order to assure sufficient power supply to meet the needs of its customers. The annual requirements and resource tabulation is also updated when significant changes are known.

Avista updated its annual requirements and resources tabulation in January 2001 when there was an adjustment to loads and changes in contracts with BPA and Snohomish PUD. These changes and other minor adjustments are explained below.

The system load update, done in the summer of 2000, incorporated known and measurable changes in customer facilities and equipment. For example, changes included shopping malls, big-box retail chains, universities and hospitals that have completed or begun major expansions.

The PacifiCorp Exchange contract is assumed to terminate after March 2004. The other contract that Avista has with PacifiCorp, which is a summer sale, is assumed to end September 30, 2003 by PacifiCorp not exercising their option to extend for five years.

The ten year sale agreement (beginning October 1996) that the company has with Snohomish PUD is now scheduled to terminate starting October 2001.

The planning reserves were adjusted to reflect the changes in the forecasted peak loads.

Company's system hydro and contract hydro was adjusted slightly to reflect the latest final hydro regulation done by the NWPP. The energy output from system hydro was increased 3 aMW and the contract hydro was decreased 2 aMW.

The other contract that was changed on the tabulation was the BPA-WNP #3. This contract with BPA under the WNP #3 Settlement has agreements for an exchange of energy. BPA has the option to request a major portion of the energy back if it is needed by their system. In December 2000 BPA requested the energy back from Avista. And since the requirements and resources tabulation is based on critical water conditions it will be assumed that under those conditions BPA will ask for the energy. BPA's energy to Avista is approximately 43 aMW and based on availability factors of nuclear surrogate units the energy from Avista to BPA is about 33 aMW. The result to Avista is a net delivery on an annual basis of 10 aMW.

The capability of Kettle Falls was increased one MW to a total of 49 MW.

The surplus (deficit) figures were adjusted to reflect these changes. The magnitude of these changes varied depending on the year. For the year 2004 (the year Avista requested resources under the 2000 RFP) the peak deficit went from 287 MW to 235 MW. The energy deficit went from 318 aMW to 287 aMW. These analyses show a continuing need for electrical resources to meet the company's customer requirements.

AVISTA CORP.

Requirements and Resources figures in MW (critical water)		2000		2001		2002		2003		2004		2005		2006		2007		2008		2009	
Line No.	REQUIREMENTS	Pk	Avg	Pk	Avg	Pk	Avg	Pk	Avg	Pk	Avg	Pk	Avg	Pk	Avg	Pk	Avg	Pk	Avg	Pk	Avg
1	System Load	1566	1001	1610	1027	1554	974	1605	1006	1662	1046	1713	1084	1755	1111	1806	1142	1859	1176	1915	1210
2	PacifiCorp Exchange	0	3	0	3	0	3	0	3	0	0	0	0	0	0	0	0	0	0	0	0
3	Puget #2	100	75	67	50	33	25	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	PacifiCorp 1994	0	9	0	9	0	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	PGE #1	150	0	150	0	150	0	150	0	150	0	150	0	150	0	150	0	150	0	150	0
6	Shomomish 10 yr	100	88	100	66	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Cogentrix 57 mo	100	100	100	75	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	Nichols Pumping	0	7	0	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	West Kootenay	125	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Eugene Water & Electric	10	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	PGE Sale	25	25	25	25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Pend Oreille	6	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	Montana Sale	100	100	100	58	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14	Duke Sale	100	100	100	58	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Clark2 PUD	250	137	250	85	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16	City of Cheney	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Reserves	247	0	251	0	245	0	250	0	256	0	261	0	266	0	271	0	276	0	282	0
18	TOTAL REQUIREMENTS	2881	1655	2755	1482	1982	1011	2005	1018	2068	1046	2124	1084	2171	1111	2227	1142	2285	1176	2347	1210

RESOURCES		2000		2001		2002		2003		2004		2005		2006		2007		2008		2009	
		Pk	Avg	Pk	Avg	Pk	Avg	Pk	Avg	Pk	Avg	Pk	Avg	Pk	Avg	Pk	Avg	Pk	Avg	Pk	Avg
19	System Hydro	946	316	946	316	946	316	946	316	946	316	946	316	946	316	946	316	946	316	946	316
20	Contract Hydro	195	74	195	74	195	74	195	74	195	74	195	74	195	74	195	74	195	74	195	74
21	Can Ent Return	-10	-5	-10	-5	-10	-5	-10	-5	-15	-5	-15	-4	-11	-4	-10	-4	-10	-4	-10	-3
22	Small Power	12	11	12	11	12	11	12	11	12	11	12	11	12	11	12	11	12	11	12	11
23	Cogeneration	59	55	59	55	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24	Northeast CTs	69	5	69	5	69	5	69	5	69	5	69	5	69	5	69	5	69	5	69	5
25	Rathdrum CTs	176	62	176	62	176	62	176	62	176	62	176	62	176	62	176	62	176	62	176	62
26	PacifiCorp Exchange	50	3	50	3	50	3	50	3	50	3	50	3	50	3	50	3	50	3	50	3
27	BPA/Avista Exchange	32	12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Entitlement & Supplemental	5	0	4	0	4	0	4	0	0	0	0	0	0	0	0	0	0	0	0	0
29	BPA Res. Exchange	0	0	0	12	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47
30	BPA-WNP #3	82	10	82	10	82	10	82	10	82	10	82	10	82	10	82	10	82	10	82	10
31	CSPE	10	5	9	5	9	5	8	1	0	0	0	0	0	0	0	0	0	0	0	0
32	TransAlta-Centralia	200	138	200	143	200	143	200	143	0	0	0	0	0	0	0	0	0	0	0	0
33	Thermal- Kettle Falls	49	45	49	45	49	45	49	45	49	45	49	45	49	45	49	45	49	45	49	45
34	Colstrip	222	191	222	191	222	191	222	191	222	191	222	191	222	191	222	191	222	191	222	191
35	SEMPRA	0	19	0	19	0	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	BPA 5 yr. Purchase	115	115	115	86	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
37	Idaho Purchase	100	100	100	58	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
38	Duke Purchase	100	100	100	58	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
39	MIECO	25	25	25	25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
40	Cinergy Services, Inc.	0	14	0	14	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
41	Energy Services, Inc.	0	50	0	25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
42	Enron	50	50	50	25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
43	TOTAL RESOURCES	2487	1395	2453	1237	2051	914	2050	903	1833	759	1783	752	1732	756	1835	833	1835	833	1835	828
44	SURPLUS (DEFICIT)	-394	-260	-302	-225	69	-97	45	-115	-235	-287	-341	-332	-439	-355	-392	-309	-450	-343	-512	-382