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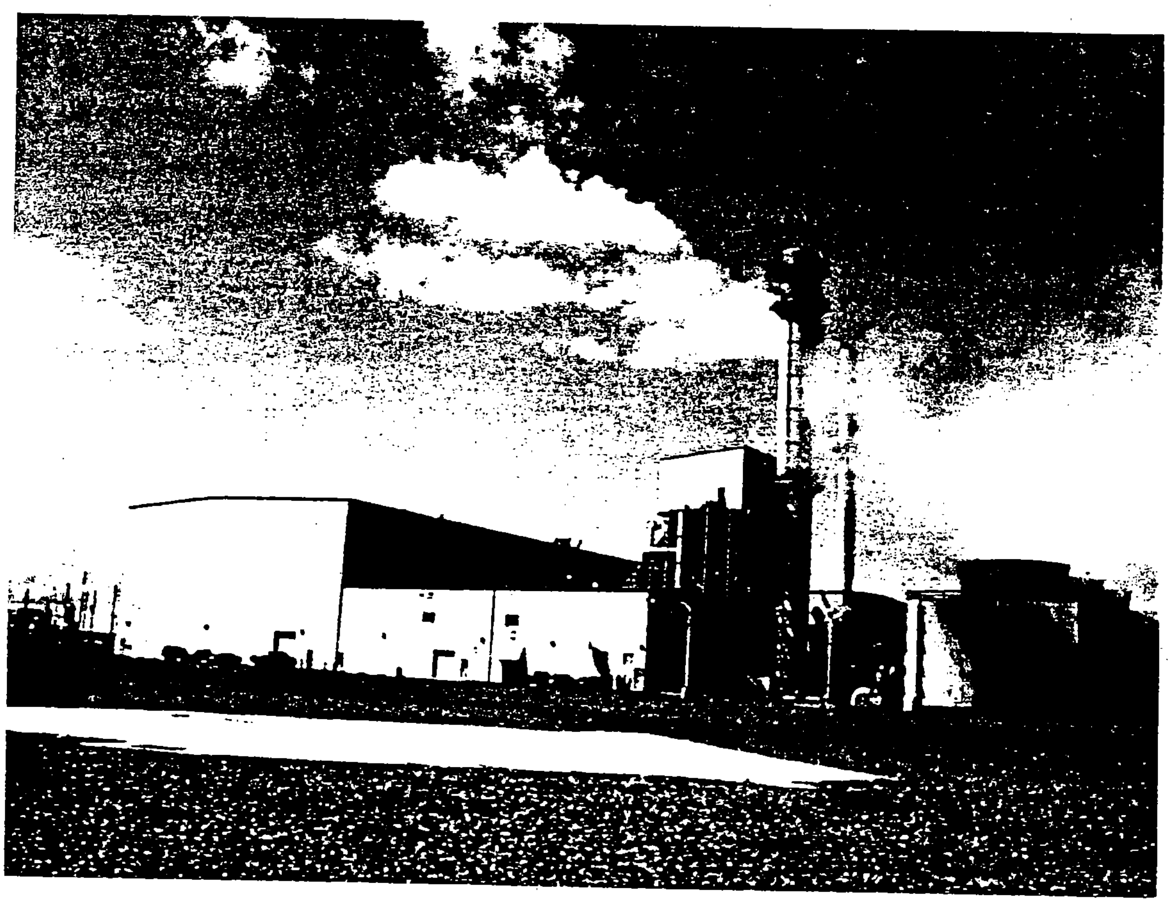
# 2001 Electric Integrated Resource Plan



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.

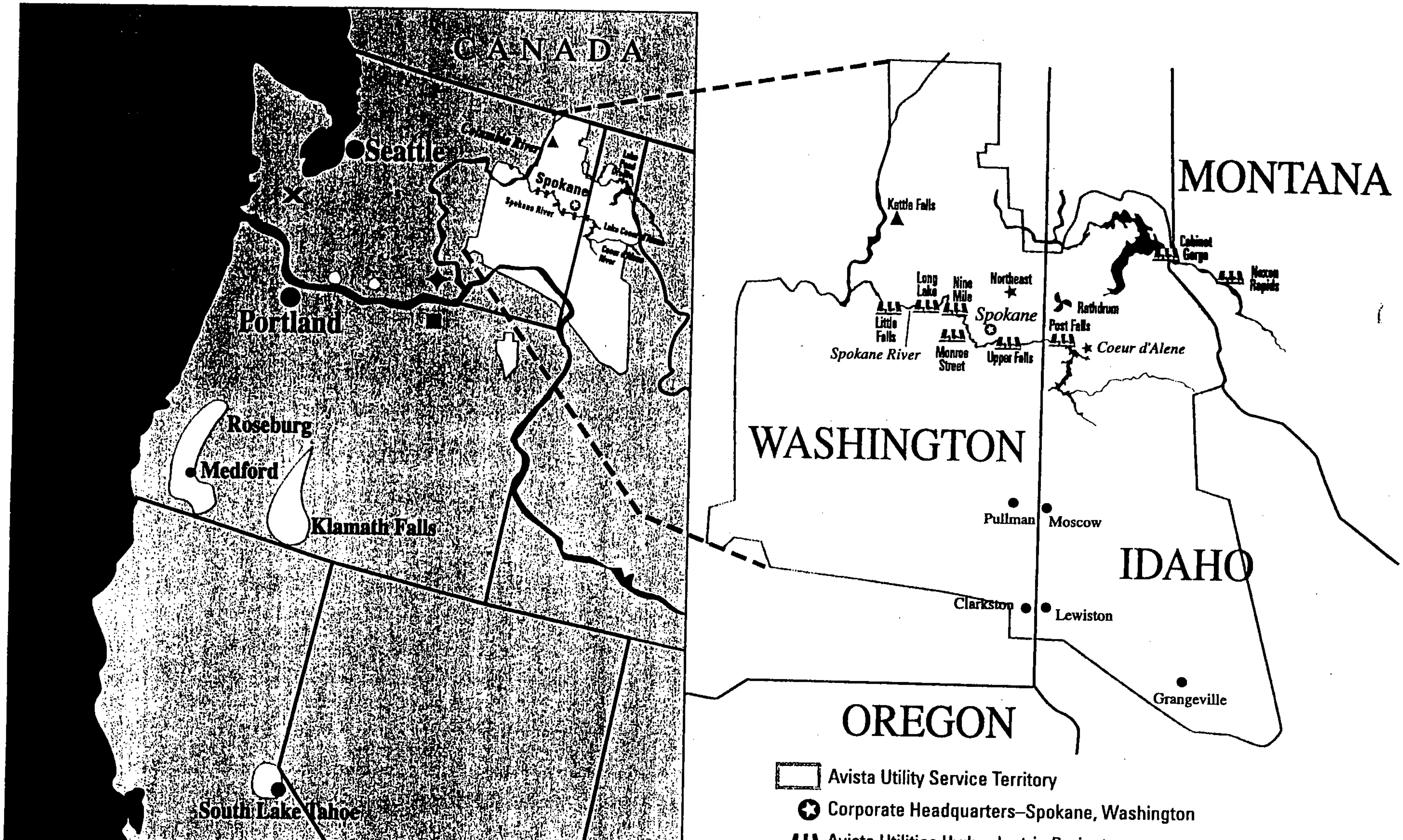
4. Installed inlet coolers at Rathdrum combustion turbines for additional summer peaking output (completed July, 2000).
5. Evaluated RFP bids, compared to company options, and selected options that were cost effective and that best met company's long-term resource need (completed December 2000). Complete 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.




- Avista Utility Service Territory
- Corporate Headquarters–Spokane, Washington
- Avista Utilities Hydroelectric Projects
- Kettle Falls Wood-Waste-Fueled Generating Station
- Rathrdrum 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

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# APPENDIX A

# 1997 ACTION PLAN

## SUMMARY REPORT FOR 1997 ACTION PLAN

In the 1997 Electric IRP, Avista listed specific action plan activities, which were to be accomplished during the past two-year planning cycle. This appendix summarizes the company's progress on these individual action items. More detailed reports on many of these activities can be found in the other appendices. The 1997 Action Items appear on the left-hand column in italics followed with a summary of the company's response in the right column.

**Reduce Company Costs**

| | |
|---|---|
| *Evaluate the benefits of selling off high cost generating resources by August 1997.* | Cost effective analysis was done on all of the company's generating resources. Meyers Falls, a small hydro facility, was sold in 1999 and Avista's share of Centralia, a coal-fired plant in western Washington, was sold in 2000. |
| *When feasible, buy out high cost energy purchase contracts.* | Avista contacted all high cost purchase contract owners (PURPA facilities) to see if they would be interested in a buyout. The company was not able to finalize any buyout. |
| *Reduce operating costs at existing generating plants.* | Avista is constantly striving to come up with ways to drive the average cost of production down. Automation is currently being placed in some of the hydro projects. |
| *Develop strategies to renew low cost energy purchase contracts* | Several discussions and agencies rulings on this item have decreased Avista's expectations but the company is continuing to work toward a favorable outcome. |

**Increase Company Revenues**

| | |
|---|---|
| *Expand Avista's energy services and Avista Advantage into* additional *retail markets.* | Avista Corp.'s subsidiaries have expanded into into new markets, with Avista Advantage conducting business in all 50 states. |
| *Increase wholesale sales through Avista's wholesale section and Avista Energy.* | Avista Utilities has exceeded its goals in wholesale markets. But Avista Corp. has refocused to concentrate on the western part of the U.S. with the closing of Avista Energy's offices in Boston and Houston. |
| *Increase customers through expansion of system infrastructure and acquisition, as opportunities become available.* | Although the company has pursued some opportunities, none have been successful so far. |

*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 capital spending and approval of annual and long-term mine plans and budgets. The Colstrip Project began combining workforces in 1998 between employee maintenance crews for Units 1 and 2 and Units 3 and 4 and reduced the workforce necessary to operate and maintain the plant.

- On August 14, 2000 Avista issued a Request for Proposals (RFP) for both supply-side and demand-side resources. 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 has selected the 280 MW gas-fired Coyote Springs II generation project and three DSM resources for a total of 13 aMW.

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# 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.

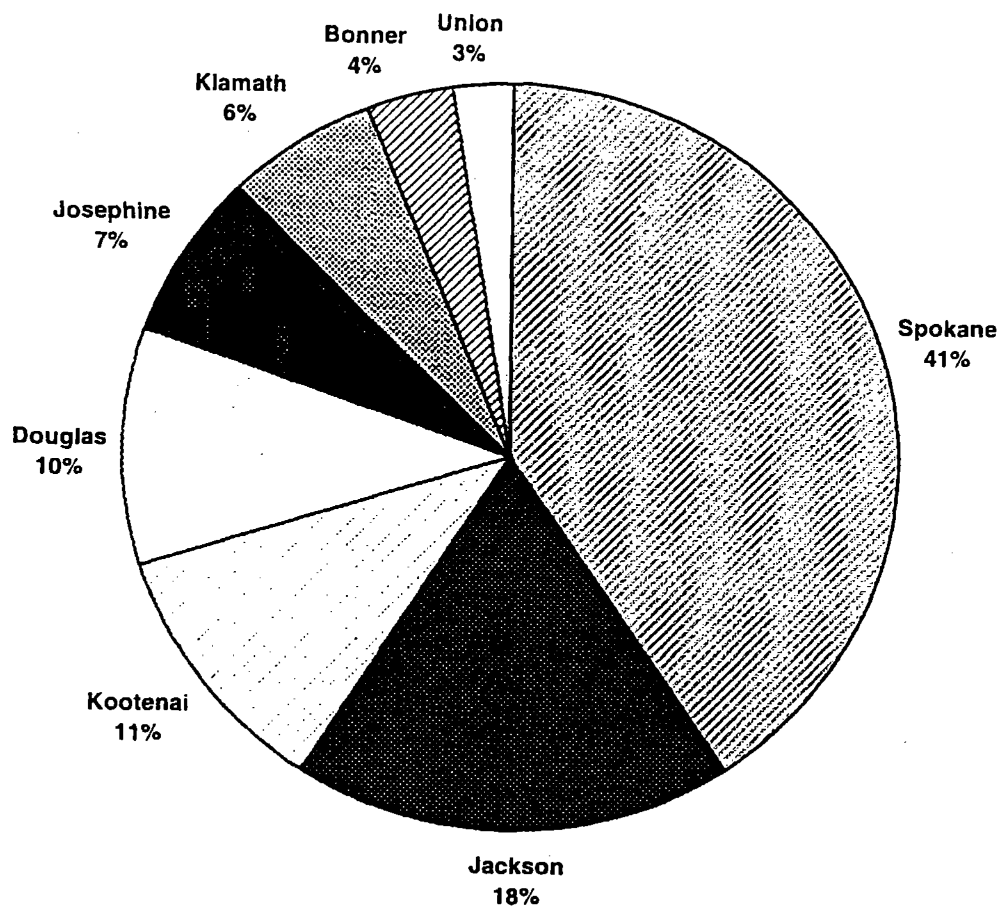
### Service Area Economic Forecasts

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



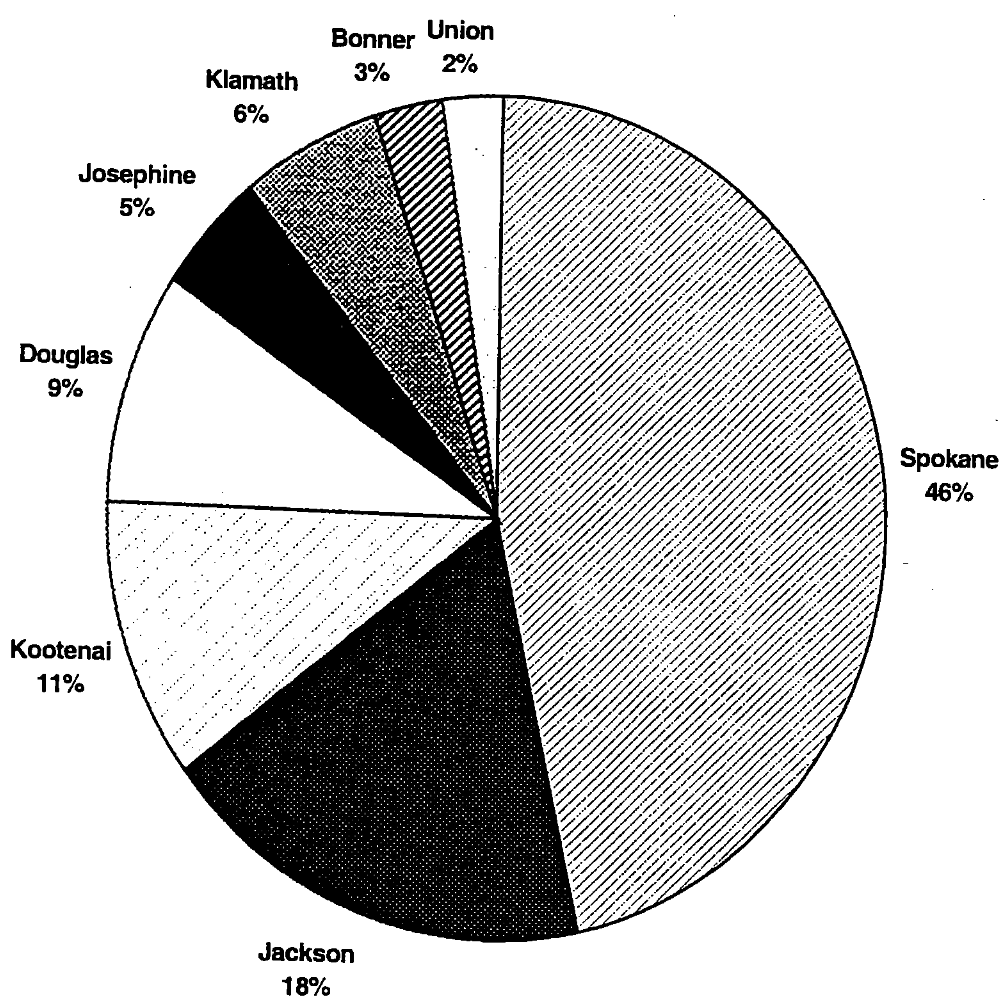

## Employment

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.

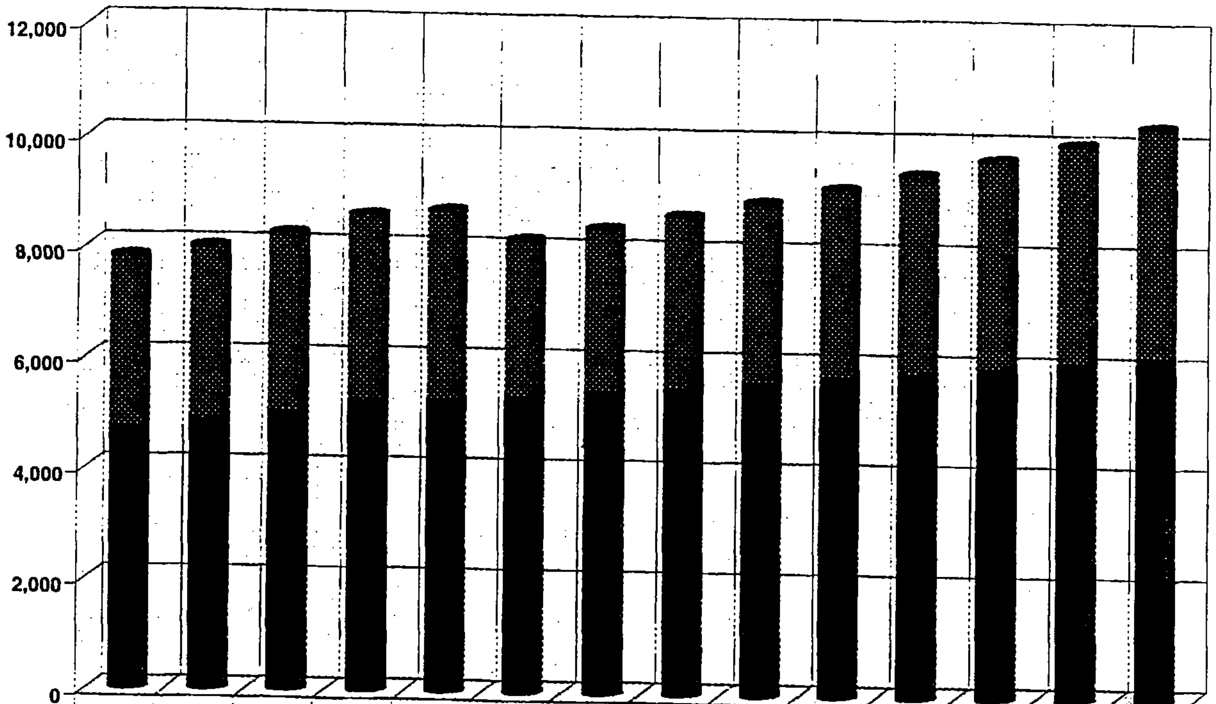
Peak load and energy forecasts are derived from the sales forecasts, as reported on the following page.

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

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

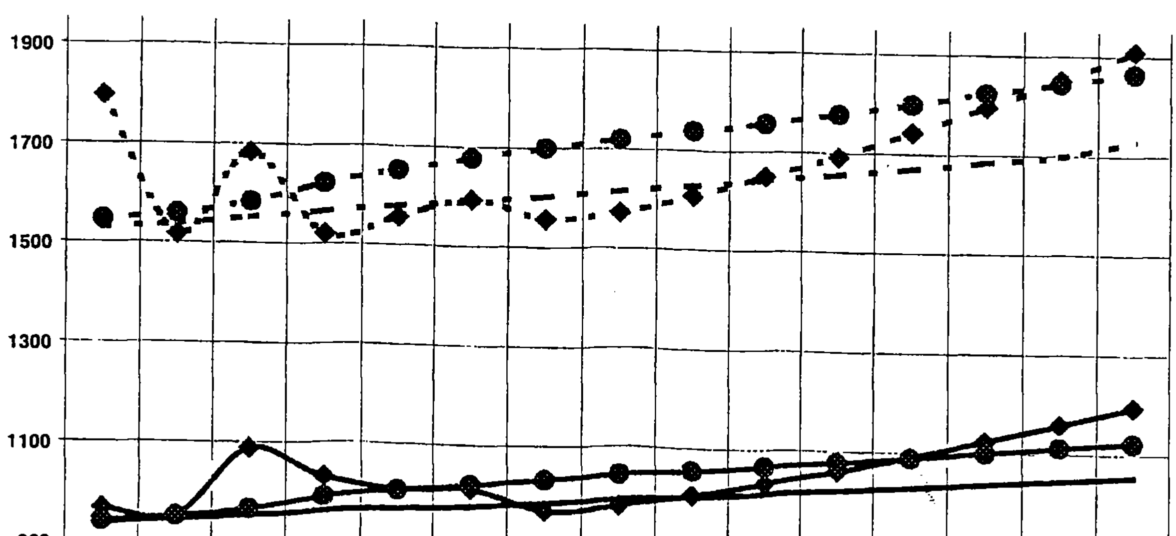
Annual Actual from 1997 to mid-1999, forecast mid-1999 thereafter:

## Total Electric Sales (million kWh)




| | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Total ID | 3,056 | 3,094 | 3,212 | 3,340 | 3,411 | 2,801 | 2,931 | 3,073 | 3,224 | 3,383 | 3,551 | 3,730 | 3,920 | 4,121 |
| Total WA | 4,771 | 4,913 | 5,049 | 5,277 | 5,303 | 5,402 | 5,503 | 5,605 | 5,709 | 5,815 | 5,923 | 6,033 | 6,145 | 6,260 |

## Avista Corp. Energy and Peak Forecast




| | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ENERGY00 | 968 | 953 | 1089 | 1031 | 1008 | 1013 | 971 | 982 | 1007 | 1033 | 1059 | 1091 | 1124 | 1159 | 1196 |
| ENERGY97 | 941 | 952 | 967 | 991 | 1007 | 1021 | 1033 | 1044 | 1055 | 1066 | 1077 | 1089 | 1101 | 1113 | 1124 |
| ENERGY95 | 938 | 946 | 954 | 963 | 970 | 978 | 987 | 994 | 1003 | 1011 | 1020 | 1029 | 1039 | 1046 | 1055 |
| PEAK00 | 1796 | 1517 | 1683 | 1521 | 1557 | 1594 | 1557 | 1572 | 1608 | 1649 | 1692 | 1743 | 1796 | 1851 | 1909 |
| PEAK97 | 1546 | 1559 | 1583 | 1623 | 1651 | 1677 | 1700 | 1719 | 1738 | 1756 | 1777 | 1799 | 1823 | 1844 | 1865 |
| PEAK95 | 1529 | 1538 | 1552 | 1566 | 1579 | 1590 | 1602 | 1615 | 1628 | 1642 | 1655 | 1669 | 1684 | 1698 | 1729 |

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# 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 dysfunctionional 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.

## RISK MANAGEMENT

### Renewed Focus on Risk related to Energy Resources

Avista Utilities has recently updated its Energy Resources Risk Policy. The recent dramatic increases in volatility to prices in the West have dictated a reduction in Volumetric Limits. The company experiences fluctuations in customer loads and in generation capability and is continually optimizing on an hourly, daily, monthly, yearly and for several years into the future, while insuring that it meets firm power commitments. This process requires projections of the many variables that impact balancing loads and resources. These projections provide an estimate of any gaps between loads and resources. The above mentioned Volumetric Limits govern maximum exposure to pricing fluctuations.

The following excerpt from Avista Utilities Energy Resources Risk Policy provides insight on the management of risk related to energy products.

### Company Philosophy toward Risk

Avista Corp. will honor its commitments to provide reliable energy services at a reasonable cost for its utility customers. Avista Corp. recognizes that there are inherent risks to income from Energy Resources operations in its electric and natural gas utility. Risks are driven by uncertain load obligations, by the nature of energy resources, by the energy marketplace, and by the manner that various regulatory constraints affect the business. It is Avista Corp.'s intention that income risk be moderated to maintain financial health of the company.

Avista Corp.'s Energy Resources operations are intended to fulfill the utility's obligation to meet its firm power commitments and dispatch company-owned and company-controlled resources and manage contracts efficiently, while minimizing costs. Avista Corp.'s Energy Resources operation is not intended to add risk by taking positions in the market beyond what is prudent to manage imbalances between committed utility loads and the power resources under Avista Corp.'s control.

Avista recognizes the variability of its power load requirements and the variability of certain generating resources output capacity because of weather and streamflow conditions. Avista also recognizes the risks of operational and delivery of power that are inherent with such resources, including unplanned outages with varying durations. Since there are inherent differences between forward estimates and actual energy loads or resources, it is necessary to both buy and sell energy in hourly, daily, monthly and longer increments to match actual resources to actual energy requirements. Avista acknowledges there are risks of counterparty non-performance and variability in prices for power and fuel for generation.

## 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**

| Year | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 |
|---|---|---|---|---|---|---|---|
| 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.

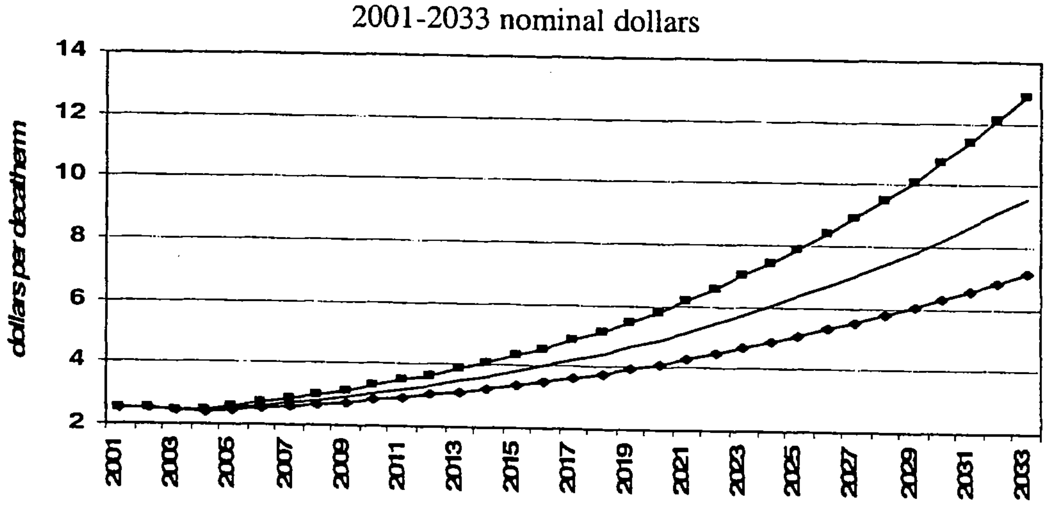
*Natural Gas and Electricity Price Forecasts*

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.

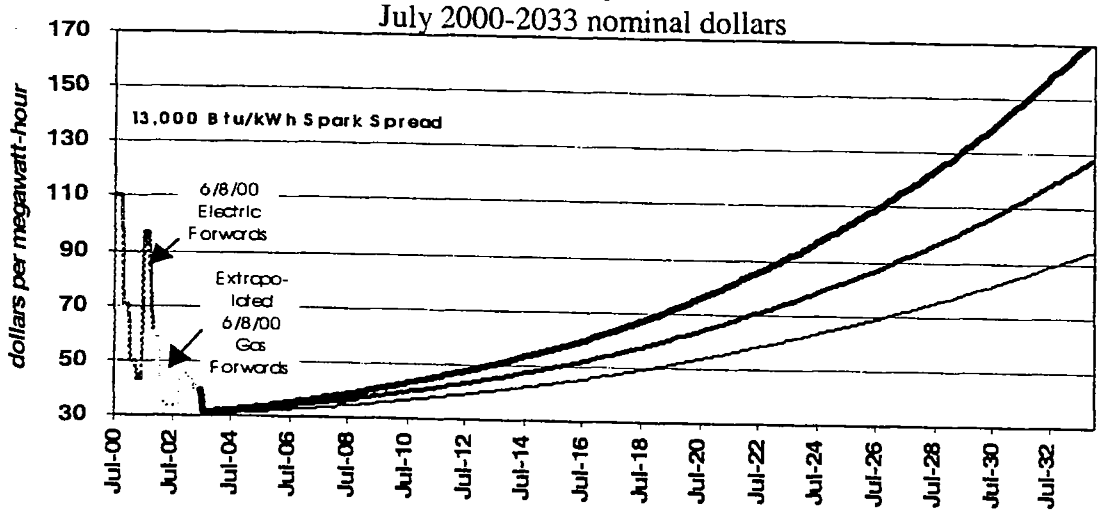
Where the spark spread is assumed to be fifteen thousand Btu/kWh, our high case estimate, electricity prices equal $39 per MWh in 2004. Prices rise to $61 in 2013 and then to $153 in 2033. The average annual price escalation again is 4.8 percent nominal. In real terms, prices rise from $36 in 2004 to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

AVISTA® Corp.

# 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 innovative bids from project developers. The RFP bids were evaluated against the information that had been gathered both internally and externally.

## 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 (4th 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 suplement 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
Photovoltaic
Micro-turbines
Magnetic energy storage
Diesel engines
Wind systems
Flywheels
Stirling engines
Solar-dish stirling
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%.

**Photovaltaic** 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 shear 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 |

| | 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 |

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# 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 environ-mentally 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 where 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.

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# 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 hydrolectric 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 like to maintain a degree of diversity in the type of resources added. Diversity in resource types and fuel supply can be beneficial in the long-term. The gas-fired Coyote Springs II generating plant meets these criteria.

Under the 2000 RFP Avista also selected three energy efficiency proposals that were cost effective and would provide benefits to the company. Avista is committed to maintaining a DSM presence in its service territory for the foreseeable future. During the past few years the company has used a tariff rider to finance its energy efficiency measures. The tariff rider provides a way to expense the cost of the programs so that a regulatory asset is not kept on the books. Avista collects between $4 and 5 million that is used to fund energy savings of 4 to 5 aMW per year plus market transformation programs.

The preferred case also assumes that there will be no significant degradation of generation on the Spokane River system due to hydro-relicensing. The company will use a collaborative relicensing process, similar to that successfully used to relicense the Clark Fork hydro facilities. Avista expects that the new Spokane River FERC license will be more restrictive than in the past. Annual energy production could be shaped into different periods thereby modifying annual production.

As maintenance and replacement conditions dictate, there will be opportunities for cost-effective hydro and thermal upgrades. Some of the opportunities include 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. Other opportunities include the addition of a small natural gas-fired combustion turbine at Kettle Falls, with the exhaust heat being used to increase the efficiency of the wood-fired plant. Ways to decrease the discharge pollutants at our combustion turbine facilities and thereby increase the annual allowable operating hours are also being studied and evaluated, as well as the addition of supply or generating units to handle variability in hydro, loads and outages.

Avista will also continue to work on reducing resource costs so that the resources remain price competitive. The preferred resource strategy should provide, at this time, what is needed to prepare the company for the competitive future. In addition it will be least cost, flexible, and provide value to the company and its customers.

**SUMMARY:**

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

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

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# 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**

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

1 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.

2 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.

3. 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.

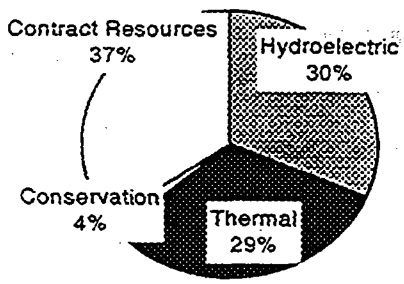
This appendix discusses the resources and contracts that are coordinated to achieve the IRP objective. Specifically, Avista's current need for resources is described. This is then followed by an outline of the power sales agreements Avista holds with utilities and power producers throughout the region.

### 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) |
|---|---|
| **AVISTA RESOURCES** | |
| Hydroelectric | 313aMW |
| Thermal | 303aMW |
| Conservation | 43aMW |
| **CONTRACT RESOURCES** | |
| Hydroelectric | 87 aMW |
| Cogeneration | 55aMW |
| Utility Purchases | 250aMW |
| Total Resources | 1051 aMW |

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.

**AVISTA CORP.** **Table G-3** **G-6**

**Requirements and Resources**
figures in MW

| | | 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 | 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 | 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 | 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 | 71 | 140 | 50 | 140 | 50 | 140 | 50 | 140 | 44 |
| 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 | 72 | 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 average of 60 years along with the hourly requirement of forecast net system loads, known contracts (both supply and requirements), and existing resources. The result shows the percent of time and magnitude of surplus and deficiency for each year studied.

Load growth expectations based on the forecasted methodologies are explained in Appendix B. Avista doesn't expect drastic changes in our load beyond the normal load growth that has been experienced. But the future is uncertain and Avista needs to be flexible enough to handle unforeseen changes. For example, the company could lose load by having Avista's larger retail customers install cogeneration, like WSU, or Potlatch could decide to serve all their own load from existing generating facilities. Or if partial deregulation was to come to our region, Avista could pick up some industrial loads thereby increasing the load requirement.

# Table G-4

## Avista Utilities
## System Physical Surplus/(Deficiency) — Critical Hydro Conditions
## 2004

| Month & Hours | Net System Load | PacifiCorp Exchange | Spokane Upriver | Contract Resources: Small Power | BPA Subscrip | BPA WNP #3 | Contract Requirements: Can Ent Rtn | PGE #1 | SnoPud | Cogen. | Colstrip | Kettle Falls | NE | Rathdrum | Mid C Hydro | Clark Fork & Spokane Hydro | Total Resource | Total Obligation | Physical Surplus/ (Deficiency) | New Flexible Resource Acquisition | Physical Surplus/ (Deficiency) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2004 | | | | | | | | | | | | | | | | | | | | | |
| Jan HL | 1314 | -18.8 | -11 | -4 | -47 | -82 | 5 | 56.25 | 100 | 0 | -200 | -47 | 0 | -173 | -94 | -242 | -918 | 1475 | -557 | -270 | -287 |
| Jan LL | 1030 | 0.0 | -11 | -4 | -47 | -119 | 5 | -71.5 | 100 | 0 | -200 | -47 | 0 | -85 | -70 | -132 | -715 | 1064 | -348 | -270 | -78 |
| Feb HL | 1222 | -18.8 | -11 | -4 | -47 | -82 | 5 | 56.25 | 100 | 0 | -200 | -47 | 0 | 0 | -63 | -317 | -789 | 1383 | -593 | -270 | -323 |
| Feb LL | 946 | 0.0 | -11 | -4 | -47 | -119 | 5 | -71.5 | 100 | 0 | -200 | -47 | 0 | 0 | -46 | -169 | -643 | 979 | -337 | -270 | -67 |
| Mar HL | 1113 | 0.0 | -12 | -5 | -47 | -41 | 5 | 56.25 | 100 | 0 | -200 | -47 | 0 | 0 | -59 | -299 | -709 | 1274 | -565 | -270 | -295 |
| Mar LL | 835 | 0.0 | -12 | -5 | -47 | -61 | 5 | -71.50 | 100 | 0 | -200 | -47 | 0 | 0 | -43 | -156 | -571 | 868 | -298 | -135 | -163 |
| Apr HL | 1049 | 0.0 | -13 | -5 | -47 | -41 | 5 | 56.25 | 100 | 0 | -200 | -47 | 0 | 0 | -57 | -390 | -799 | 1211 | -411 | -270 | -141 |
| Apr LL | 791 | 0.0 | -13 | -5 | -47 | -61 | 5 | -71.50 | 0 | 0 | -200 | -47 | 0 | 0 | -43 | -204 | -620 | 724 | -104 | 0 | -104 |
| May HL | 1046 | 0.0 | -11 | -5 | -47 | 0 | 5 | 56.25 | 100 | 0 | -200 | -47 | 0 | 0 | -96 | -594 | -1000 | 1208 | -208 | 0 | -208 |
| May LL | 788 | 0.0 | -11 | -5 | -47 | 0 | 5 | -71.50 | 0 | 0 | -200 | -47 | 0 | 0 | -77 | -501 | -887 | 722 | 165 | 0 | 165 |
| Jun HL | 1071 | 0.0 | -10 | -5 | -47 | 0 | 5 | 56.25 | 100 | 0 | -96 | 0 | 0 | 0 | -104 | -700 | -962 | 1232 | -270 | -270 | 0 |
| Jun LL | 774 | 0.0 | -10 | -5 | -47 | 0 | 5 | -71.50 | 0 | 0 | -96 | -47 | 0 | 0 | -89 | -632 | -926 | 707 | 219 | 0 | 219 |
| Jul HL | 1050 | 0.0 | | -4 | -47 | 0 | 5 | 56.25 | 100 | 0 | -200 | -47 | 0 | -130 | -70 | -336 | -834 | 1211 | -377 | -270 | -107 |
| Jul LL | 765 | 0.0 | | -4 | -47 | 0 | 5 | -71.50 | 100 | 0 | -200 | -47 | 0 | 0 | -61 | -245 | -603 | 799 | -196 | -270 | 74 |
| Aug HL | 1060 | 0.0 | | -3 | -47 | 0 | 5 | 56.25 | 100 | 0 | -200 | -47 | -35 | -139 | -88 | -390 | -948 | 1221 | -273 | -270 | -3 |
| Aug LL | 768 | 0.0 | | -3 | -47 | 0 | 5 | -71.50 | 100 | 0 | -200 | -47 | 0 | -70 | -67 | -158 | -592 | 802 | -210 | -270 | 60 |
| Sep HL | 964 | 0.0 | | -3 | -47 | 0 | 5 | 56.25 | 100 | 0 | -200 | -47 | -35 | -143 | -84 | -232 | -790 | 1125 | -335 | -270 | -65 |
| Sep LL | 715 | 0.0 | | -3 | -47 | 0 | 5 | -71.50 | 100 | 0 | -200 | -47 | 0 | -72 | -63 | -112 | -543 | 748 | -205 | -270 | 65 |
| Oct HL | 1079 | 0.0 | | -3 | -47 | 0 | 5 | 56.25 | 100 | 0 | -200 | -47 | -35 | -161 | -88 | -242 | -822 | 1240 | -418 | -270 | -148 |
| Oct LL | 816 | 0.0 | | -3 | -47 | 0 | 5 | -71.50 | 100 | 0 | -200 | -47 | 0 | -70 | -69 | -111 | -546 | 850 | -304 | -270 | -34 |
| Nov HL | 1173 | 0.0 | | -3 | -47 | -82 | 5 | 56.25 | 100 | 0 | -200 | -47 | 0 | -167 | -91 | -327 | -963 | 1335 | -371 | -270 | -101 |
| Nov LL | 911 | 0.0 | | -3 | -47 | -119 | 5 | -71.50 | 100 | 0 | -200 | -47 | 0 | 0 | -74 | -152 | -641 | 945 | -304 | -270 | -34 |
| Dec HL | 1271 | 0.0 | | -3 | -47 | -82 | 5 | 56.25 | 100 | 0 | -200 | -47 | 0 | -171 | -116 | -429 | -1094 | 1433 | -339 | -270 | -69 |
| Dec LL | 1010 | 0.0 | | -3 | -47 | -119 | 5 | -71.50 | 100 | 0 | -200 | -47 | 0 | 0 | -84 | -243 | -742 | 1043 | -301 | -270 | -31 |
| AVE | 1007 | -1.8 | -5.7 | -3.9 | -47.0 | -41.1 | 5.0 | 0.0 | 89.0 | 0.0 | -190.9 | -44.8 | -4.9 | -61.4 | -76.0 | -313.1 | -790.5 | 1092.1 | -301.6 | -222.8 | -78.8 |
| | | | | | | | | | | | | | | | | | Ave HLH | | -393 | -248 | -146 |
| | | | | | | | | | | | | | | | | | Ave LLH | | -185 | -191 | 6 |

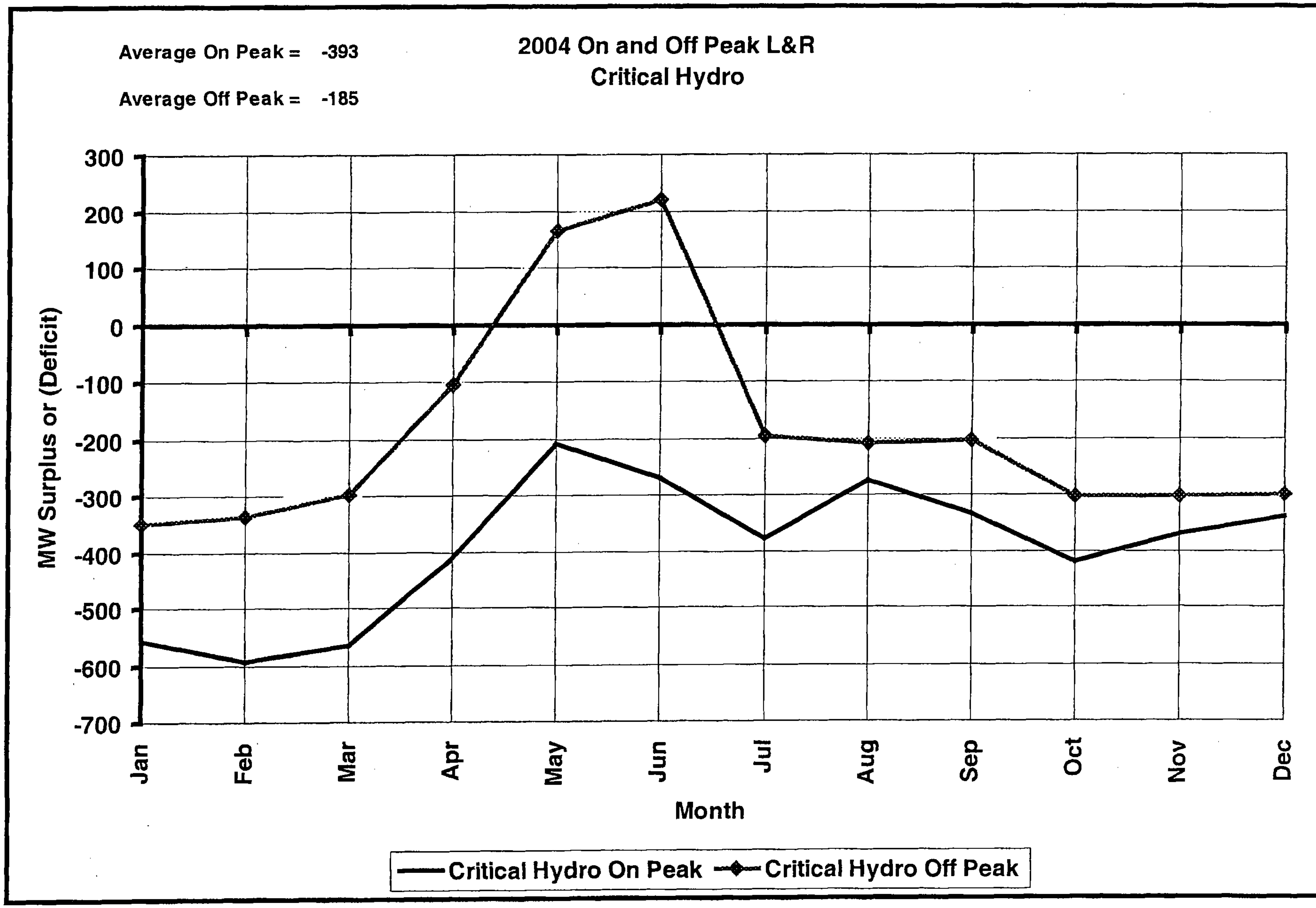

Average On Peak = -393
Average Off Peak = -185
2004 On and Off Peak L&R
Critical Hydro
300
200
100
0
-100
-200
-300
-400
-500
-600
-700
MW Surplus or (Deficit)
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Month
Critical Hydro On Peak
Critical Hydro Off Peak

Figure G-1

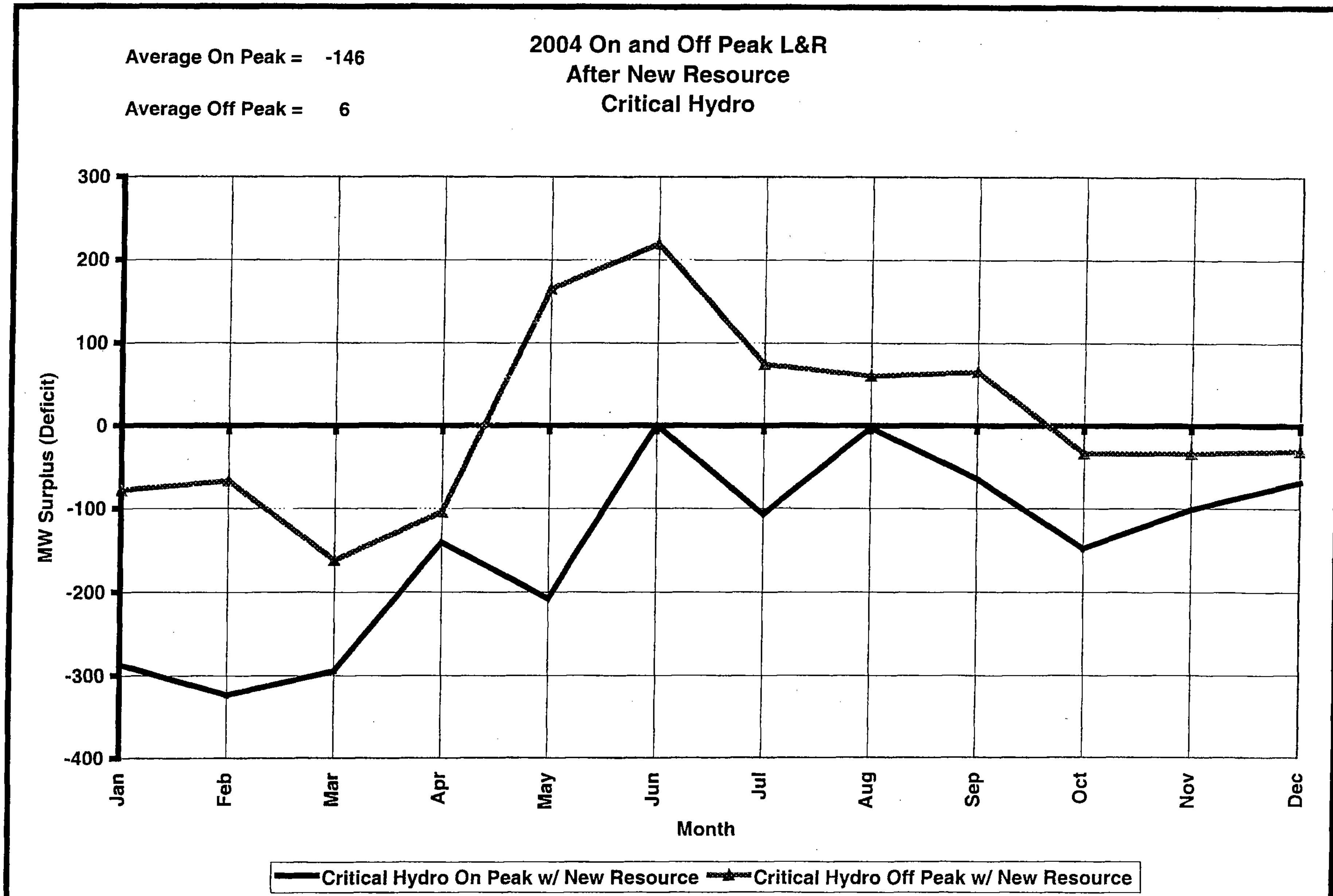

Average On Peak = -146
Average Off Peak = 6
2004 On and Off Peak L&R
After New Resource
Critical Hydro
300
200
100
0
-100
-200
-300
-400
MW Surplus (Deficit)
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Month
Critical Hydro On Peak w/ New Resource
Critical Hydro Off Peak w/ New Resource

Figure G-2

# Avista Utilities

## System Physical Surplus/(Deficiency) — Normal Hydro Conditions

## 2004

| Month & Hours | Net System Load | PacifiCorp Exchange | Contract Resources: Spokane Upriver | Contract Resources: Small Power | Contract Resources: BPA Subscrip | Contract Resources: BPA WNP #3 | Contract Requirements: Can Ent Rtn | Contract Requirements: PGE #1 | Contract Requirements: SnoPud | Cogen. | Colstrip | Kettle Falls | NE | Rathdrum | Mid C Hydro | Clark Fork & Spokane Hydro | Total Resource | Total Obligation | Physical Surplus/ (Deficiency) | New Flexible Resource Acquisition | Physical Surplus/ (Deficiency) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2004 | | | | | | | | | | | | | | | | | | | | | |
| Jan HL | 1314 | -18.8 | -11 | -4 | -47 | -82 | 5 | 56.25 | 100 | 0 | -200 | -47 | 0 | -173 | -125 | -505 | -1212 | 1475 | -263 | -270 | 7 |
| Jan LL | 1030 | 0.0 | -11 | -4 | -47 | -119 | 5 | -71.5 | 100 | 0 | -200 | -47 | 0 | -85 | -103 | -276 | -892 | 1064 | -172 | -270 | 98 |
| Feb HL | 1222 | -18.8 | -11 | -4 | -47 | -82 | 5 | 56.25 | 100 | 0 | -200 | -47 | 0 | 0 | -124 | -548 | -1081 | 1383 | -302 | -270 | -32 |
| Feb LL | 946 | 0.0 | -11 | -4 | -47 | -119 | 5 | -71.5 | 100 | 0 | -200 | -47 | 0 | 0 | -103 | -292 | -823 | 979 | -157 | -270 | 113 |
| Mar HL | 1113 | 0.0 | -12 | -5 | -47 | -41 | 5 | 56.25 | 100 | 0 | -200 | -47 | 0 | 0 | -113 | -546 | -1011 | 1274 | -264 | -270 | 6 |
| Mar LL | 835 | 0.0 | -12 | -5 | -47 | -61 | 5 | -71.50 | 100 | 0 | -200 | -47 | 0 | 0 | -93 | -286 | -751 | 868 | -118 | -135 | 17 |
| Apr HL | 1049 | 0.0 | -13 | -5 | -47 | -41 | 5 | 56.25 | 100 | 0 | -200 | -47 | 0 | 0 | -106 | -669 | -1128 | 1211 | -83 | -270 | 187 |
| Apr LL | 791 | 0.0 | -13 | -5 | -47 | -61 | 5 | -71.50 | 0 | 0 | -200 | -47 | 0 | 0 | -91 | -350 | -814 | 724 | 89 | 0 | 89 |
| May HL | 1046 | 0.0 | -11 | -5 | -47 | 0 | 5 | 56.25 | 100 | 0 | -200 | -47 | 0 | 0 | -94 | -782 | -1186 | 1208 | -22 | 0 | -22 |
| May LL | 788 | 0.0 | -11 | -5 | -47 | 0 | 5 | -71.50 | 0 | 0 | -200 | -47 | 0 | 0 | -85 | -659 | -1054 | 722 | 332 | 0 | 332 |
| Jun HL | 1071 | 0.0 | -10 | -5 | -47 | 0 | 5 | 56.25 | 100 | 0 | -96 | 0 | 0 | 0 | -101 | -775 | -1034 | 1232 | -198 | -270 | 72 |
| Jun LL | 774 | 0.0 | -10 | -5 | -47 | 0 | 5 | -71.50 | 0 | 0 | -96 | -47 | 0 | 0 | -98 | -700 | -1003 | 707 | 296 | 0 | 296 |
| Jul HL | 1050 | 0.0 | | -4 | -47 | 0 | 5 | 56.25 | 100 | 0 | -200 | -47 | 0 | -130 | -114 | -555 | -1097 | 1211 | -114 | -270 | 156 |
| Jul LL | 765 | 0.0 | | -4 | -47 | 0 | 5 | -71.50 | 100 | 0 | -200 | -47 | 0 | 0 | -112 | -405 | -815 | 799 | 16 | -270 | 286 |
| Aug HL | 1060 | 0.0 | | -3 | -47 | 0 | 5 | 56.25 | 100 | 0 | -200 | -47 | -35 | -139 | -103 | -337 | -911 | 1221 | -311 | -270 | -41 |
| Aug LL | 768 | 0.0 | | -3 | -47 | 0 | 5 | -71.50 | 100 | 0 | -200 | -47 | 0 | -70 | -91 | -137 | -595 | 802 | -207 | -270 | 63 |
| Sep HL | 964 | 0.0 | | -3 | -47 | 0 | 5 | 56.25 | 100 | 0 | -200 | -47 | -35 | -143 | -87 | -326 | -888 | 1125 | -237 | -270 | 33 |
| Sep LL | 715 | 0.0 | | -3 | -47 | 0 | 5 | -71.50 | 100 | 0 | -200 | -47 | 0 | -72 | -72 | -157 | -598 | 748 | -151 | -270 | 119 |
| Oct HL | 1079 | 0.0 | | -3 | -47 | 0 | 5 | 56.25 | 100 | 0 | -200 | -47 | -35 | -161 | -86 | -362 | -940 | 1240 | -300 | -270 | -30 |
| Oct LL | 816 | 0.0 | | -3 | -47 | 0 | 5 | -71.50 | 100 | 0 | -200 | -47 | 0 | -70 | -76 | -166 | -609 | 850 | -241 | -270 | 29 |
| Nov HL | 1173 | 0.0 | | -3 | -47 | -82 | 5 | 56.25 | 100 | 0 | -200 | -47 | 0 | -167 | -101 | -449 | -1095 | 1335 | -240 | -270 | 30 |
| Nov LL | 911 | 0.0 | | -3 | -47 | -119 | 5 | -71.50 | 100 | 0 | -200 | -47 | 0 | 0 | -93 | -208 | -717 | 945 | -228 | -270 | 42 |
| Dec HL | 1271 | 0.0 | | -3 | -47 | -82 | 5 | 56.25 | 100 | 0 | -200 | -47 | 0 | -171 | -117 | -454 | -1120 | 1433 | -313 | -270 | -43 |
| Dec LL | 1010 | 0.0 | | -3 | -47 | -119 | 5 | -71.50 | 100 | 0 | -200 | -47 | 0 | 0 | -95 | -257 | -768 | 1043 | -276 | -270 | -6 |
| AVE | 1007 | -1.8 | -5.7 | -3.9 | -47.0 | -41.1 | 5.0 | 0.0 | 89.0 | 0.0 | -190.9 | -44.8 | -4.9 | -61.4 | -100.1 | -437.1 | -938.6 | 1092.1 | -153.5 | -222.8 | 69.3 |
| | | | | | | | | | | | | | | | | | Ave HLH | | -221 | -248 | 27 |
| | | | | | | | | | | | | | | | | | Ave LLH | | -68 | -191 | 123 |

Table G-5

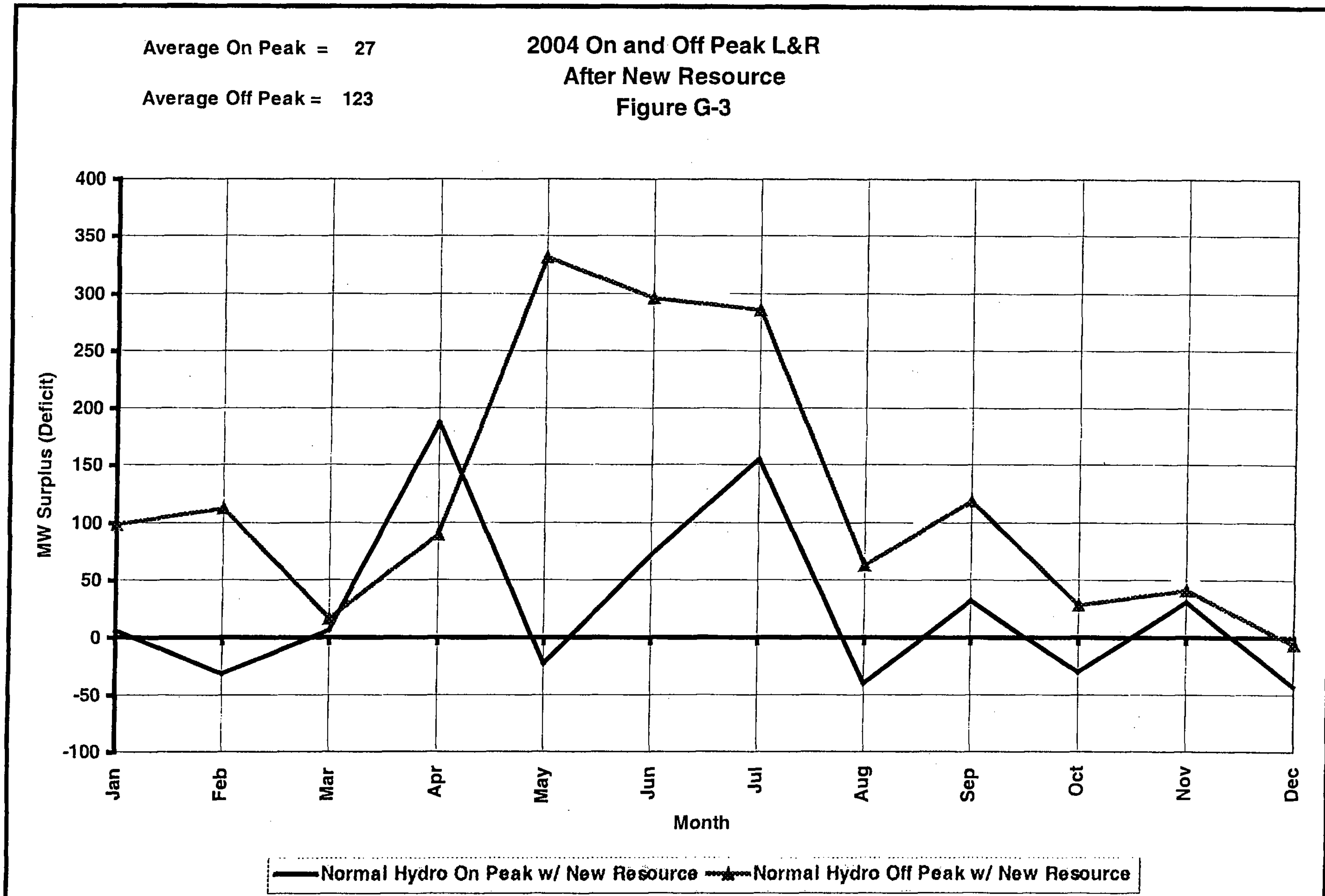

Average On Peak = 27
Average Off Peak = 123
2004 On and Off Peak L&R
After New Resource
Figure G-3
400
350
300
250
200
150
100
50
0
-50
-100
MW Surplus (Deficit)
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Month
Normal Hydro On Peak w/ New Resource
Normal Hydro Off Peak w/ New Resource

Figure G-4

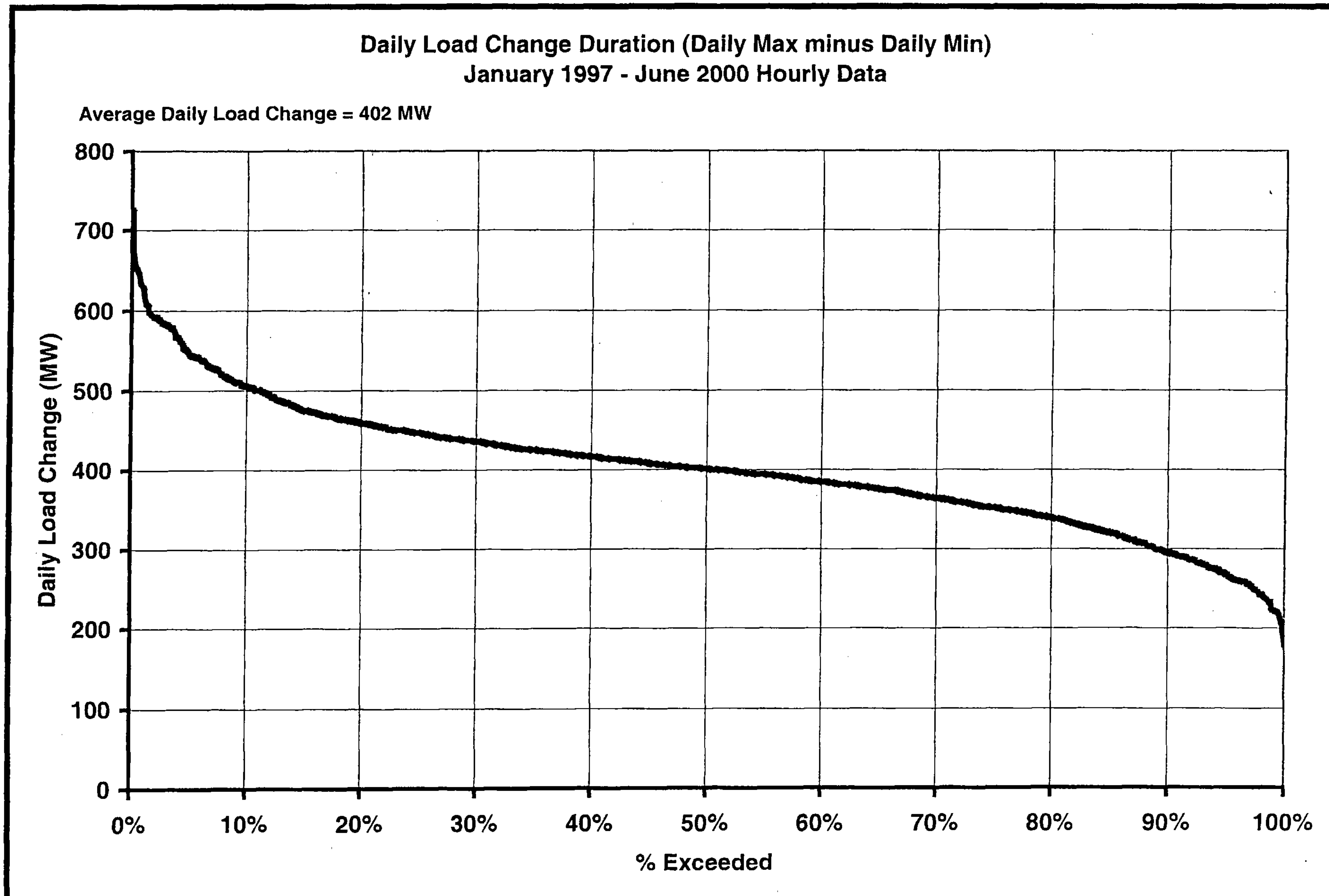
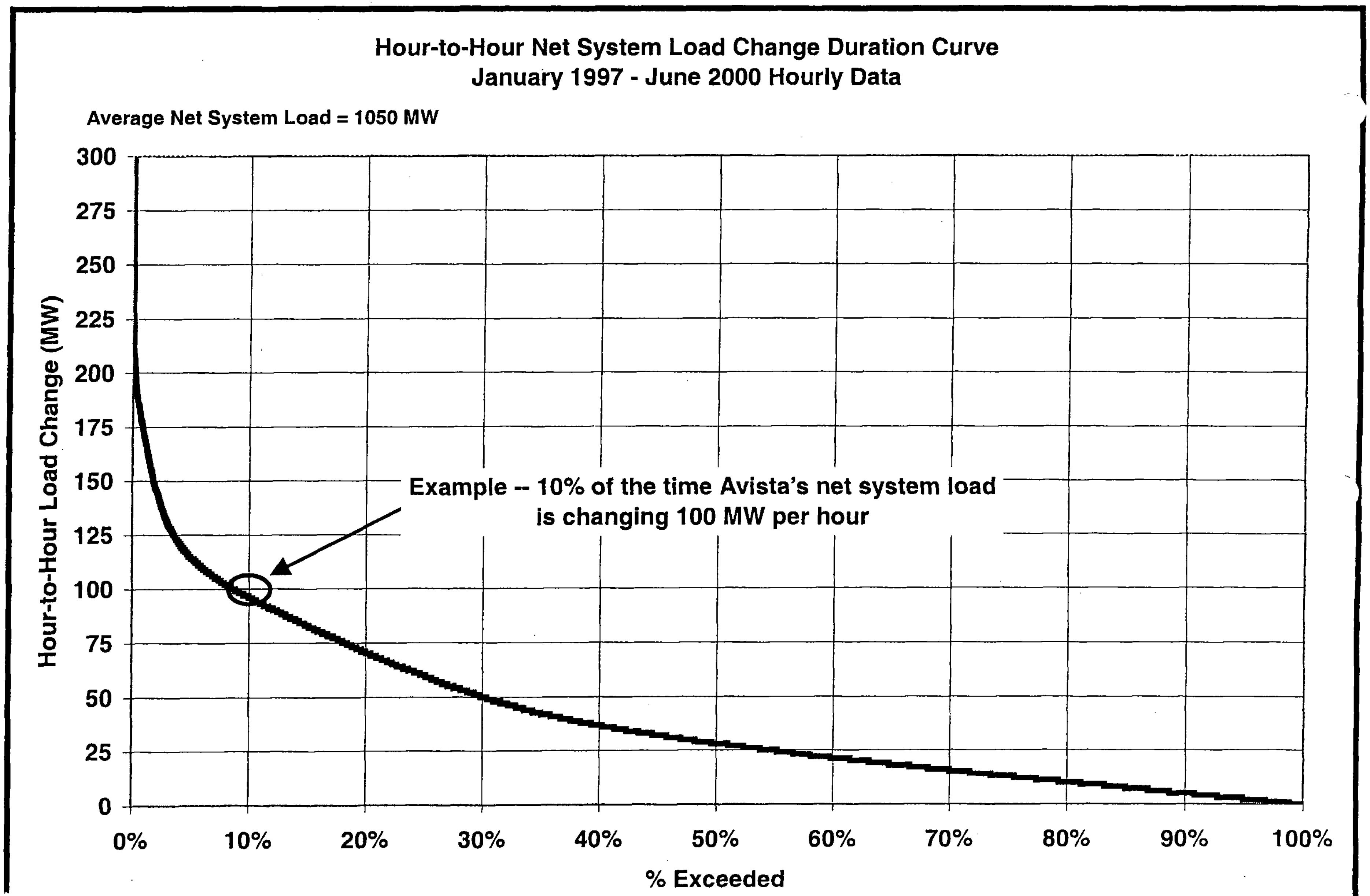

Daily Load Change Duration (Daily Max minus Daily Min)
January 1997 - June 2000 Hourly Data
Average Daily Load Change = 402 MW
800
700
600
500
400
300
200
100
0
Daily Load Change (MW)
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
% Exceeded

Figure G-5


Hour-to-Hour Net System Load Change Duration Curve
January 1997 - June 2000 Hourly Data
Average Net System Load = 1050 MW
Hour-to-Hour Load Change (MW)
300
275
250
225
200
175
150
125
100
75
50
25
0
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
% Exceeded
Example -- 10% of the time Avista's net system load is changing 100 MW per hour

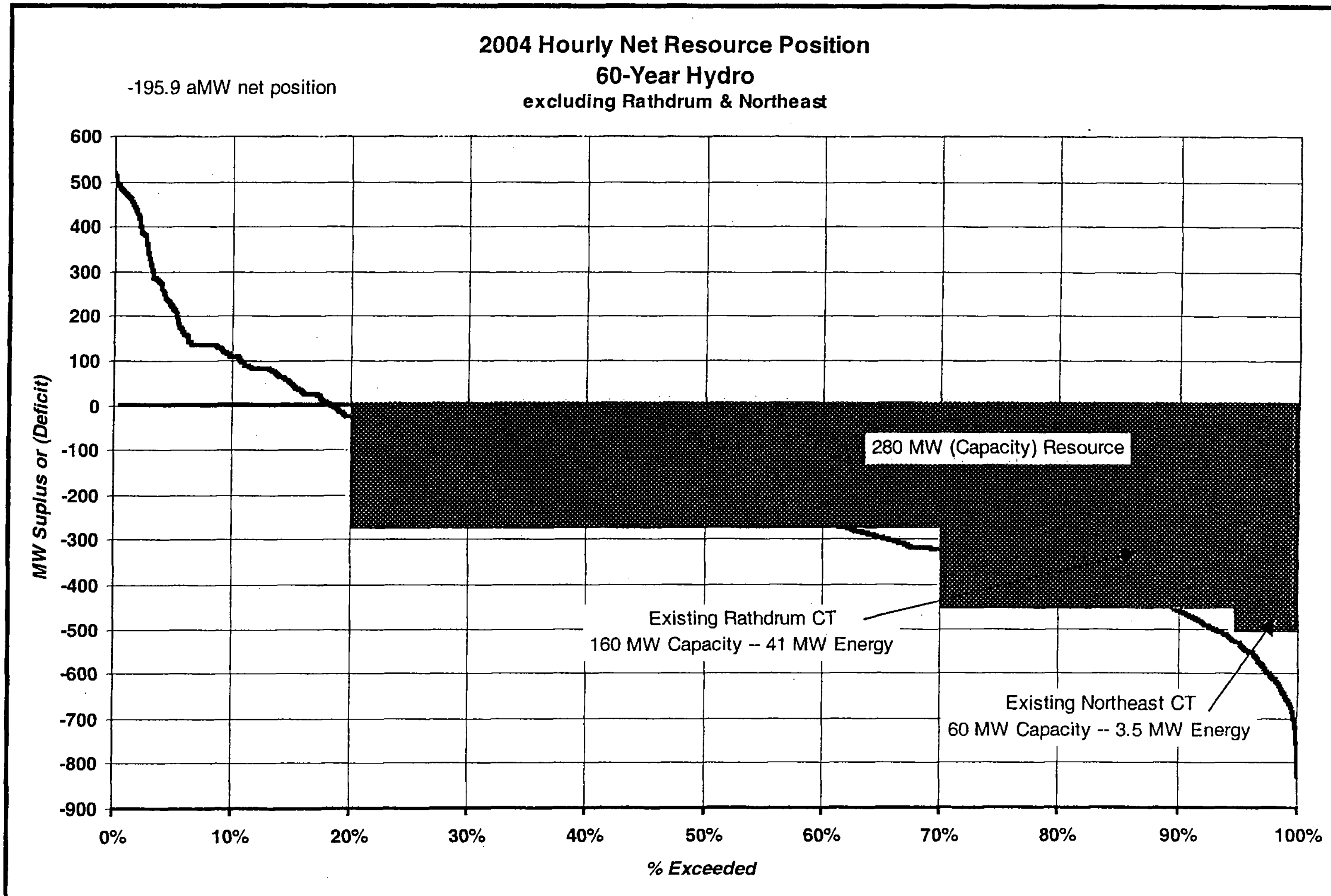
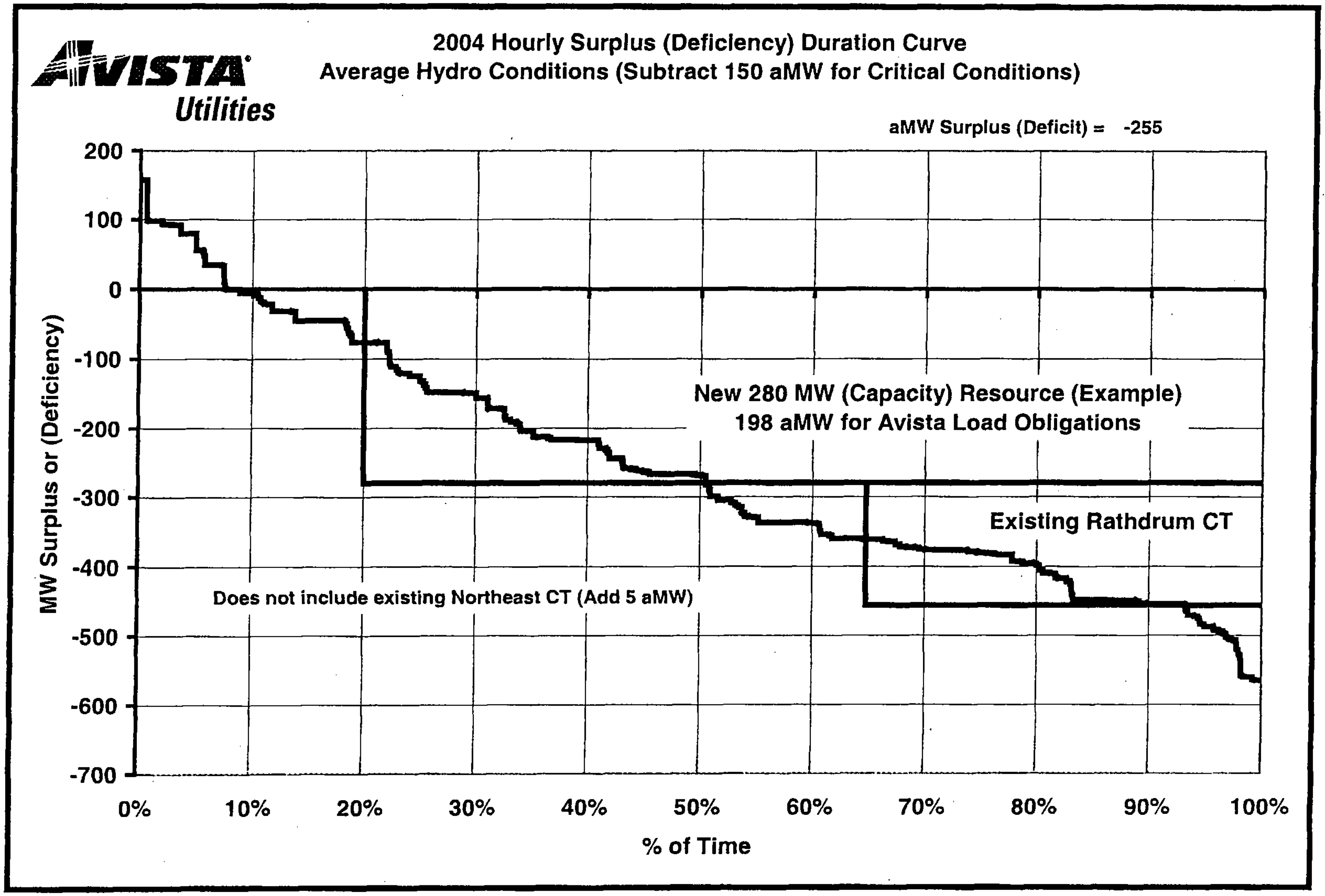

2004 Hourly Net Resource Position
60-Year Hydro
excluding Rathdrum & Northeast
-195.9 aMW net position
600
500
400
300
200
100
0
-100
-200
-300
-400
-500
-600
-700
-800
-900
MW Suplus or (Deficit)
280 MW (Capacity) Resource
Existing Rathdrum CT
160 MW Capacity -- 41 MW Energy
Existing Northeast CT
60 MW Capacity -- 3.5 MW Energy
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
% Exceeded

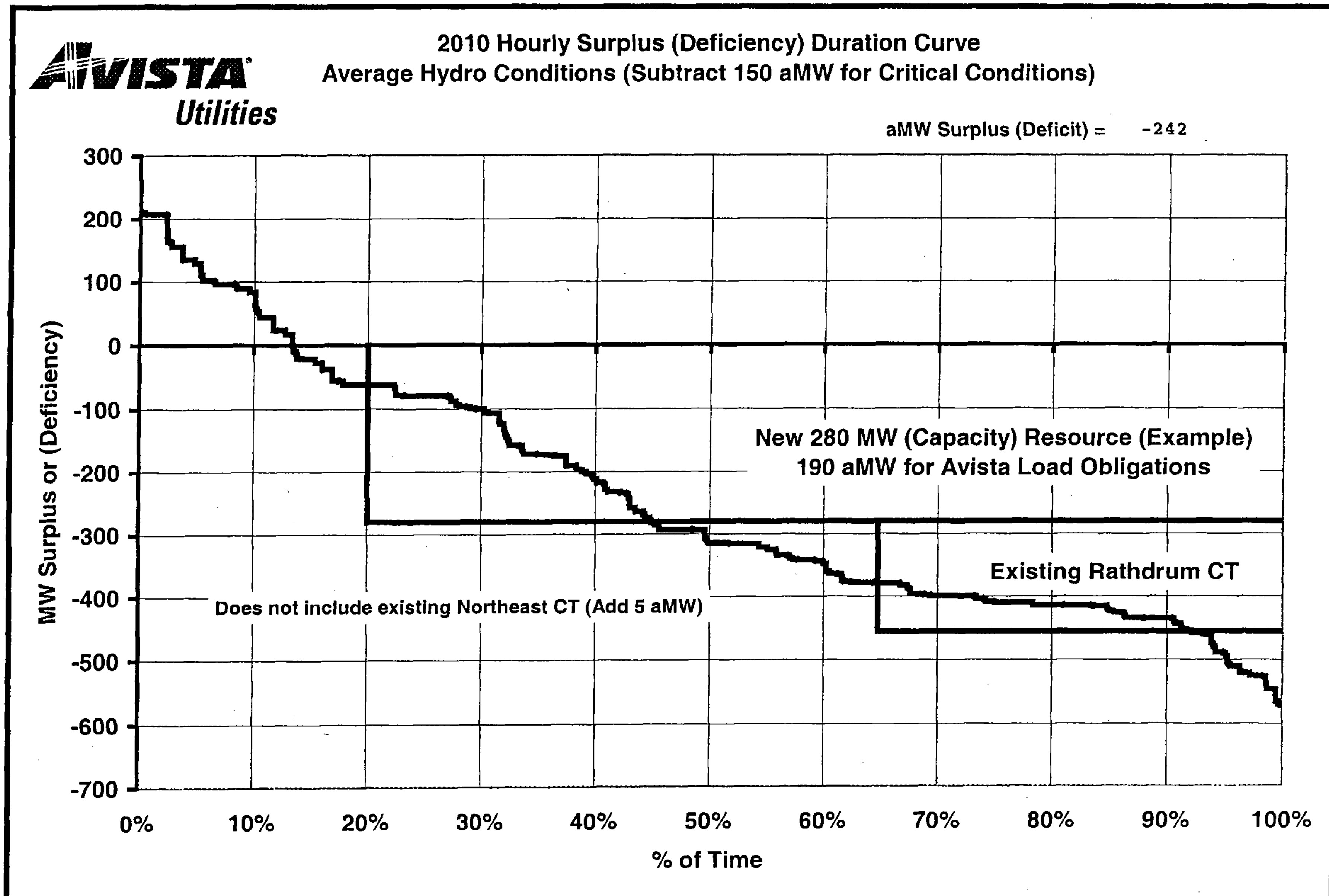
**Figure G-6**

Figure G-7



AVISTA Utilities
2004 Hourly Surplus (Deficiency) Duration Curve
Average Hydro Conditions (Subtract 150 aMW for Critical Conditions)
aMW Surplus (Deficit) = -255
MW Surplus or (Deficiency)
200
100
0
-100
-200
-300
-400
-500
-600
-700
New 280 MW (Capacity) Resource (Example)
198 aMW for Avista Load Obligations
Existing Rathdrum CT
Does not include existing Northeast CT (Add 5 aMW)
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
% of Time

Figure G-8



Utilities
2010 Hourly Surplus (Deficiency) Duration Curve
Average Hydro Conditions (Subtract 150 aMW for Critical Conditions)
aMW Surplus (Deficit) = -242
New 280 MW (Capacity) Resource (Example)
190 aMW for Avista Load Obligations
Existing Rathdrum CT
Does not include existing Northeast CT (Add 5 aMW)
MW Surplus or (Deficiency)
300
200
100
0
-100
-200
-300
-400
-500
-600
-700
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
% of Time

Figure G-9

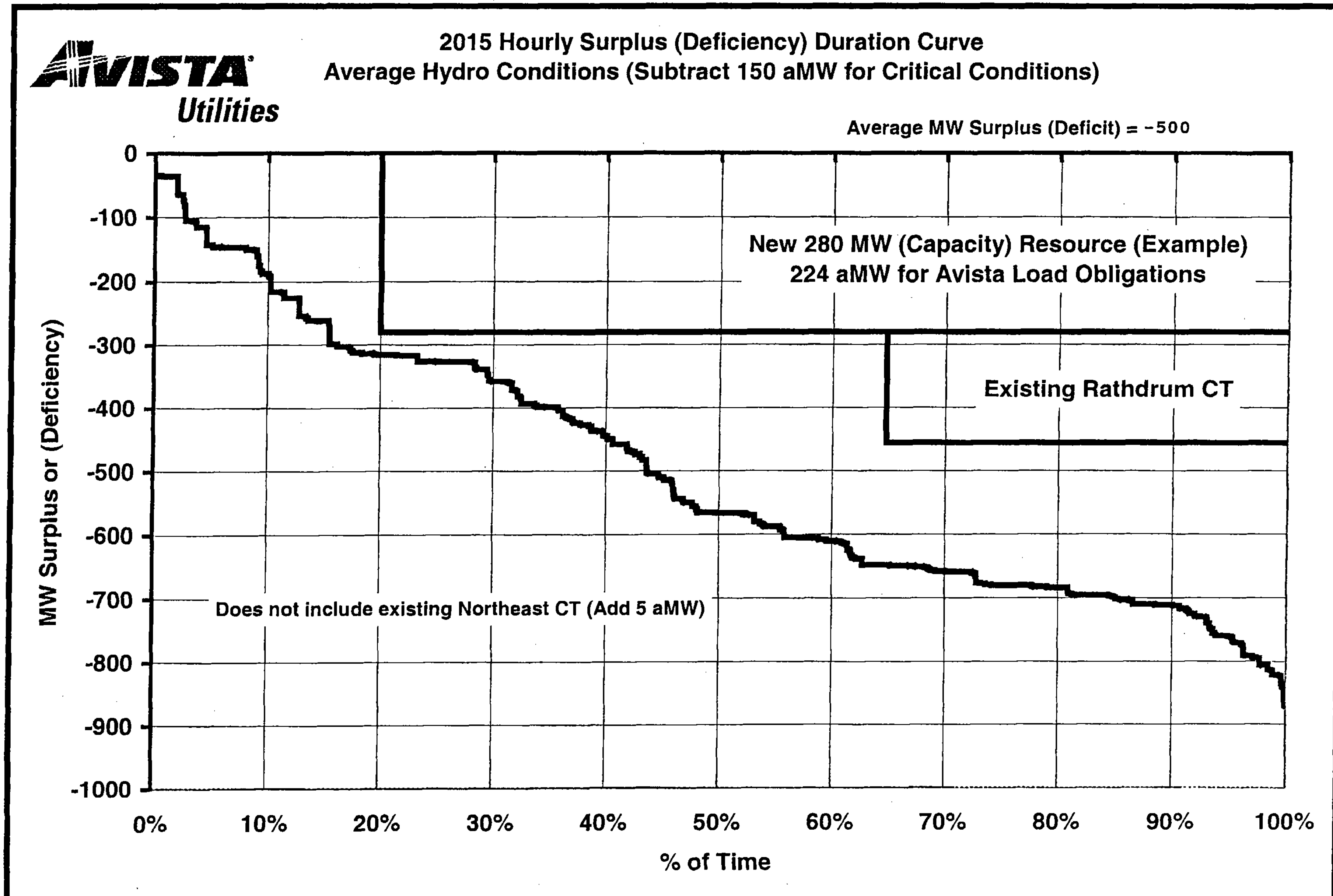
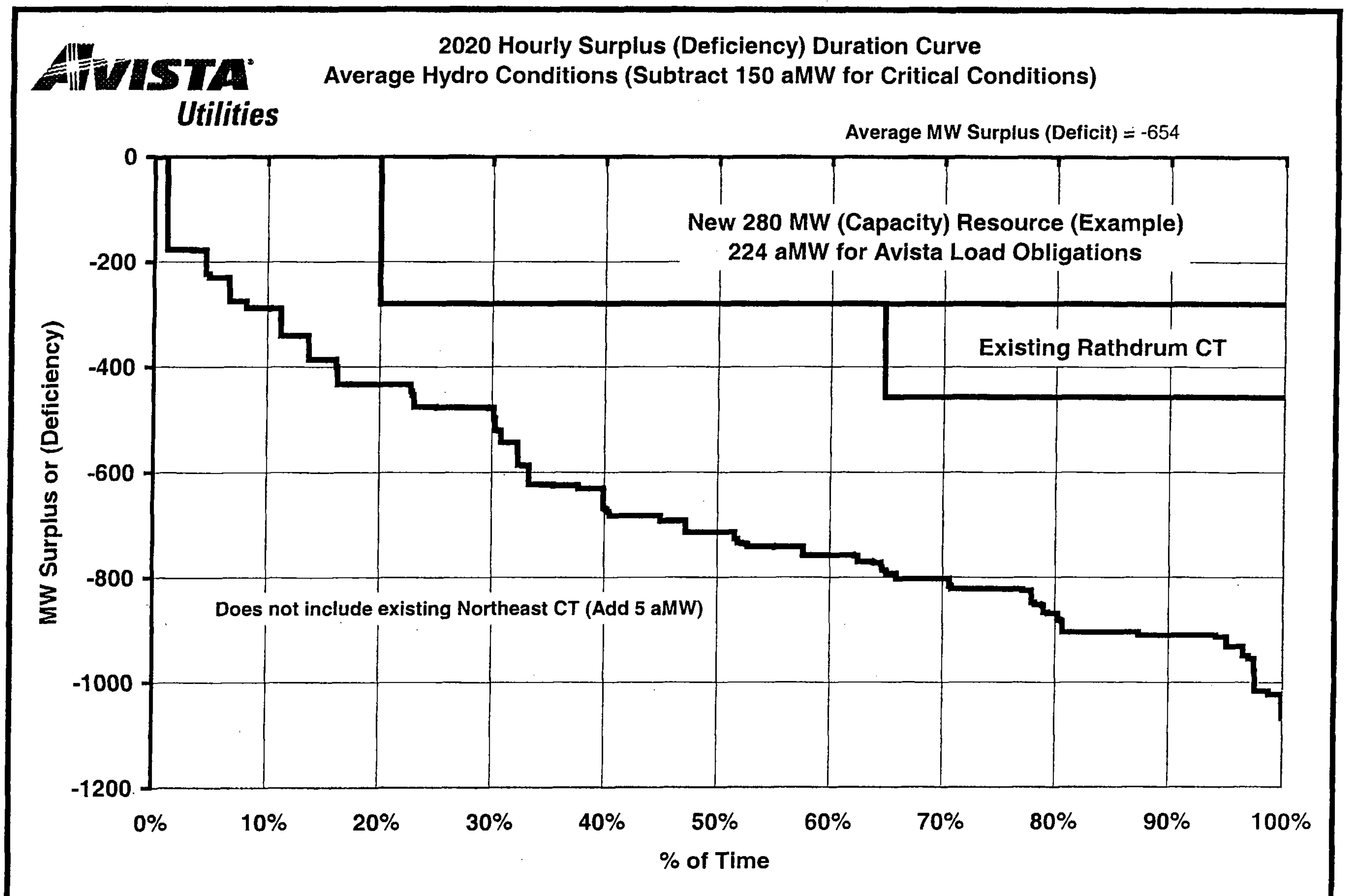

AVISTA Utilities
2015 Hourly Surplus (Deficiency) Duration Curve
Average Hydro Conditions (Subtract 150 aMW for Critical Conditions)
Average MW Surplus (Deficit) = -500
New 280 MW (Capacity) Resource (Example)
224 aMW for Avista Load Obligations
Existing Rathdrum CT
Does not include existing Northeast CT (Add 5 aMW)
MW Surplus or (Deficiency)
0
-100
-200
-300
-400
-500
-600
-700
-800
-900
-1000
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
% of Time

Figure G-10



Avista Utilities
2020 Hourly Surplus (Deficiency) Duration Curve
Average Hydro Conditions (Subtract 150 aMW for Critical Conditions)
Average MW Surplus (Deficit) = -654
New 280 MW (Capacity) Resource (Example)
224 aMW for Avista Load Obligations
Existing Rathdrum CT
Does not include existing Northeast CT (Add 5 aMW)
MW Surplus or (Deficiency)
0
-200
-400
-600
-800
-1000
-1200
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
% of Time

## 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 lead factor based on variable prices.
- Portland General Electric is purchasing from the company 150 MW of capacity through December 21, 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 year rate period, October 2001 through September 2006. The proposed settlement amounts for Avista are currently 47 aMW of power delivered flat for five years and an equivalent amount of cash equal to 43 aMW. For the subsequent five year period (starting in October 2006) the total amount proposed to be made available to Avista is 149 aMW.

Bonneville Power Administration- WNP No. 3 Settlement

On September 17, 1985, the company signed settlement agreements with BPA and the WPPSS in which the company agreed not to proceed further on the construction delay claims. In addition to settling the construction delay litigation, the BPA Settlement includes agreements for an exchange of energy, an agreement to reimburse the company for certain WNP No. 3 preservation costs and an irrevocable offer of WNP No. 3 capability for acquisition under the Regional Power Act.

Under the energy exchange portion of the BPA Settlement, the company expects to receive from BPA approximately 41 average megawatts for a period of up to 32.5 years, subject to a contract minimum of 5.8 million MWh. The company is obligated to pay BPA operating and maintenance costs associated with the energy exchange, determined by a formula in an amount not less than 1.6 cents per kWh nor more than 2.9 cents per kWh expressed in 1987 dollars, unless WNP No. 3 is completed in which case, under certain circumstances, the operating and maintenance costs may be measured by actual WNP No. 3 costs. The company began receiving power from BPA on January 1, 1987.

With the BPA Settlement, the company continues as an owner of WNP No. 3 under the Ownership Agreement and will continue to pay its ownership share of preservation costs. BPA is required to reimburse the company for the preservation costs and other costs of WNP No. 3 paid on or after February 1, 1985 through the date that WNP No. 3 is restarted or terminated. The reimbursement will be applied against the operating and maintenance costs, which the company will pay BPA under the energy exchange portion of the BPA Settlement.

Bonneville Power Administration 5-Year Purchase

Avista purchases 115 MW of annual firm energy delivered at a flat rate of delivery during all hours. This agreement began October 1996 and continues until September 30, 2001. The rate is flat for the contract term.

Columbia Storage Power Exchange (CSPE)

In 1968, the company was entitled to receive power from the Columbia Storage Power Exchange, a nonprofit Washington corporation, which purchased Canada's share of the downstream benefits resulting from the Columbia River Treaty. The company's share of the power is five percent. This contract will be in effect until the year 2003.

In conjunction with CSPE arrangements, the company has purchased Entitlement and Supplemental Capacity commencing April 1977. This is strictly a capacity purchase with the amount decreasing until 2003 when the Agreement terminates.

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 MEICO 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.

Puget Sound Energy

The company, on January 1, 1988, entered into an agreement with PSE to sell a block of power for 15 years. The contract demand is 100 MW for contract years 1988 through 2000 and 67 MW for 2001 and 33 MW for contract year 2002, unless the contract is extended for two years. The two-year extension is dependent on whether the company has minimal load growth. Energy will be delivered to PSE based on 75 percent annual load factor. Energy shall not be scheduled for any hour at a rate higher then 100 MW or less than 30 MW. The price for energy is the company's average power cost, but not to exceed BPA's new resource rate.

SEMPRA

Avista is purchasing from SEMPRA for five years firm energy of 50 MW for enumerated period of delivery. The term is August 1, 1997 through March 31, 2002 for a delivery period of August 1 through March 31 of each year.

Snohomish PUD

The contract begins October 1996 and ends September 2006. The agreement provides for the long-term sale of firm capacity and energy at fixed rates. In every month, Snohomish has the obligation to purchase the maximum amount of firm capacity (100 MW) and a minimum amount of firm energy at 50% load factor. Snohomish has the right to purchase a maximum amount of firm energy at 100% load factor.

TransAlta

Avista is purchasing power from TransAlta, the new owners of the coal-fired Centralia plant. It is a flat delivery over all hours excluding April 1 through June 30 for the year 2000 through 2003. The contract starts July 1, 2000 and the delivery rate is 200 MWh per hour.

West Kootenay

Sale of winter capacity shall be provided beginning November 1, 1995 and ending February 29, 2000. West Kootenay has the option to increase the capacity purchase amounts and to add purchase amounts for the months of October and March. West Kootenay may either purchase energy associated with the capacity or may elect to return the energy.

## 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 |

| Year | Month | Forced Outage Rate | Equivalent Availability Factor | Year | Month | Forced Outage Rate | Equivalent Availability Factor |
|---|---|---|---|---|---|---|---|
| 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 Capactiy: (Peak in MW) | Total | No. 1 | No. 2 | No. 3 | No. 4 |
|---|---|---|---|---|---|
| | 236 | 63.50 | 57.5 | 57.5 | 57.5 |

| Year | Month | Forced Outage Rate | Equivalent Availability Factor | Year | Month | Forced Outage Rate | Equivalent Availability Factor |
|---|---|---|---|---|---|---|---|
| 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 Capactiy: (Peak in MW) | Total | No. 1 | No. 2 | No. 3 | No. 4 | No. 5 | No.6 |
|---|---|---|---|---|---|---|---|
| | 18.0 | 2.9 | 2.9 | 2.9 | 2.9 | 2.9 | 3.5 |

### Upper Falls

FERC License Expiration Date : 7/31/2007

| Rated Capactiy: (Peak in MW) | Total | No. 1 |
|---|---|---|
| | 10.2 | 10.2 |

### Monroe Street

FERC License Expiration Date : 7/31/2007

| Rated Capactiy: (Peak in MW) | Total | No. 1 |
|---|---|---|
| | 14.8 | 14.8 |

### Nine Mile

FERC License Expiration Date : 7/31/2007

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

### Long Lake

FERC License Expiration Date : 7/31/2007

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

### Little Falls

FERC License Expiration Date : NA (License not required)

| Rated Capactiy: (Peak in MW) | Total | No. 1 | No. 2 | No. 3 | No. 4 |
|---|---|---|---|---|---|
| | 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%

| Year | Month | Forced Outage Rate | Equivalent Availability Factor |
|---|---|---|---|
| 1995 | Jan | 2.92 | 87.70 |
| | Feb | 1.57 | 97.95 |
| | Mar | 0.09 | 95.09 |
| | Apr | 0.00 | 99.30 |
| | May | 3.31 | 58.86 |
| | Jun | 1.91 | 19.21 |
| | Jul | 10.10 | 77.05 |
| | Aug | 5.39 | 94.21 |
| | Sep | 0.09 | 99.55 |
| | Oct | 0.07 | 91.80 |
| | Nov | 0.00 | 94.16 |
| | Dec | 0.00 | 100.00 |
| 1996 | Jan | 0.14 | 99.86 |
| | Feb | 0.93 | 99.49 |
| | Mar | 0.00 | 100.00 |
| | Apr | 0.00 | 99.31 |
| | May | 0.00 | 99.80 |
| | Jun | 16.41 | 83.51 |
| | Jul | 0.00 | 99.86 |
| | Aug | 7.56 | 92.17 |
| | Sep | 9.29 | 90.71 |
| | Oct | 0.91 | 98.91 |
| | Nov | 5.19 | 91.42 |
| | Dec | 9.43 | 90.71 |
| 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 |

| Year | Month | Forced Outage Rate | Equivalent Availability Factor |
|---|---|---|---|
| 1998 | Jan | 8.51 | 84.98 |
| | Feb | 15.19 | 85.01 |
| | Mar | 8.22 | 91.97 |
| | Apr | 0.00 | 86.53 |
| | May | 0.09 | 100.00 |
| | Jun | 0.00 | 100.00 |
| | Jul | 0.00 | 99.70 |
| | Aug | 13.14 | 87.08 |
| | Sep | 0.00 | 97.95 |
| | Oct | 27.42 | 71.73 |
| | Nov | 0.00 | 99.99 |
| | Dec | 0.00 | 99.61 |
| 1999 | Jan | 14.65 | 82.50 |
| | Feb | 27.07 | 72.23 |
| | Mar | 11.34 | 86.98 |
| | Apr | 0.18 | 98.74 |
| | May | 0.00 | 69.43 |
| | Jun | 0.15 | 99.85 |
| | Jul | 17.37 | 81.59 |
| | Aug | 4.43 | 92.76 |
| | Sep | 0.10 | 90.98 |
| | Oct | 0.36 | 95.36 |
| | Nov | 18.77 | 79.71 |
| | Dec | 0.00 | 98.22 |

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:

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

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%

| Year | Month | Forced Outage Rate | Equivalent Availability Factor | Year | Month | Forced Outage Rate | Equivalent Availability Factor |
|---|---|---|---|---|---|---|---|
| 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

| Year | Month | Forced Outage Rate | Availability Factor | Year | Month | Forced Outage Rate | Availability Factor |
|---|---|---|---|---|---|---|---|
| 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

| Year | Month | Generation - MWh | Year | Month | Generation - MWh |
|---|---|---|---|---|---|
| 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

| Year | Month | Generation - MWh |
|---|---|---|
| 1995 | Jan | 702 |
| | Feb | 826 |
| | Mar | 950 |
| | Apr | 679 |
| | May | 429 |
| | Jun | 227 |
| | Jul | 34 |
| | Aug | 1 |
| | Sep | 0 |
| | Oct | 147 |
| | Nov | 591 |
| | Dec | 613 |
| 1996 | Jan | 857 |
| | Feb | 690 |
| | Mar | 696 |
| | Apr | 1,041 |
| | May | 881 |
| | Jun | 109 |
| | Jul | 0 |
| | Aug | 0 |
| | Sep | 0 |
| | Oct | 0 |
| | Nov | 68 |
| | Dec | 464 |
| 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 |

| Year | Month | Generation - MWh |
|---|---|---|
| 1998 | Jan | 730 |
| | Feb | 639 |
| | Mar | 894 |
| | Apr | 774 |
| | May | 516 |
| | Jun | 554 |
| | Jul | 433 |
| | Aug | 254 |
| | Sep | 51 |
| | Oct | 0 |
| | Nov | 0 |
| | Dec | 360 |
| 1999 | Jan | 587 |
| | Feb | 1,040 |
| | Mar | 665 |
| | Apr | 973 |
| | May | 942 |
| | Jun | 463 |
| | Jul | 84 |
| | Aug | 0 |
| | Sep | 0 |
| | Oct | 0 |
| | Nov | 3 |
| | Dec | 57 |

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

| Year | Month | Generation-MWh |
|---|---|---|
| 1995 | Jan | 174 |
| | Feb | 526 |
| | Mar | 1,173 |
| | Apr | 1,071 |
| | May | 1,265 |
| | Jun | 1,157 |
| | Jul | 841 |
| | Aug | 293 |
| | Sep | 134 |
| | Oct | 199 |
| | Nov | 374 |
| | Dec | 912 |
| 1996 | Jan | 913 |
| | Feb | 674 |
| | Mar | 1,053 |
| | Apr | 1,139 |
| | May | 1,182 |
| | Jun | 1,045 |
| | Jul | 1,090 |
| | Aug | 406 |
| | Sep | 157 |
| | Oct | 139 |
| | Nov | 150 |
| | Dec | 104 |
| 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 |

| Year | Month | Generation-MWh |
|---|---|---|
| 1998 | Jan | 898 |
| | Feb | 469 |
| | Mar | 830 |
| | Apr | 1,218 |
| | May | 988 |
| | Jun | 1,066 |
| | Jul | 1,221 |
| | Aug | 575 |
| | Sep | 458 |
| | Oct | 139 |
| | Nov | 176 |
| | Dec | 317 |
| 1999 | Jan | 695 |
| | Feb | 748 |
| | Mar | 695 |
| | Apr | 1,142 |
| | May | 1,029 |
| | Jun | 1,121 |
| | Jul | 1,150 |
| | Aug | 1,076 |
| | Sep | 703 |
| | Oct | 254 |
| | Nov | 161 |
| | Dec | 654 |

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

| Year | Month | Generation - MWh | Year | Month | Generation - MWh |
|---|---|---|---|---|---|
| 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

| Year | Month | Generation - MWh | |
|---|---|---|---|
| 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

| Year | Month | Generation - MWh | |
|---|---|---|---|
| 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**

| Year | Month | Total Short-term Sales - MWh | Average Cost Mills/kWh | Total Short-term Purchases - MWh | Average Cost Mills/kWh |
|---|---|---|---|---|---|
| 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 |

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# 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 aquisition 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 aquisition, 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 participant 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), nongovermental 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.

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# 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. |
| $CO_2$ (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. |

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| 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 resevoirs 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 |

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| | 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. |

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| 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 | 1megawatt = 1000 kilowatts |

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| MWh | 1megawatt-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. |

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| 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, |

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| | 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. |

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# 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. Currant 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

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| 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.

In addition to local energy efficiency programs, Avista is a funding participant in the Northwest Energy Efficiency Alliance (NEEA). NEEA is a non-profit organization funded by the seven investor-own utilities and the Bonneville Power Administration to pursue market transformation opportunities on a regional basis. Avista has contractually agreed to fund NEEA for an additional five years (2000 to 2004 inclusive) with programs operating over the next seven years (to 2006). Avista dues represent 4.0% of NEEA's $100 million in funding authorizations over the five year funding period.

**External Energy Efficiency Board**

With the removal of a sunset date, continued oversight of the Tariff Rider was needed. As a result of a non-binding oversight committee consisting of regulators, public stakeholders, environmentalists and customers was put into place in the form of the External Energy Efficiency (Triple-E) Board. The Triple-E Board currently convenes annually to review program design, results, and future programs. These reviews provide an accounting of our activity, including disclosures of large projects and policy decisions as well as expenditures, energy savings, Tariff Rider revenue and cost-effectiveness.

The meetings of the Triple-E Board supplement a trimesterly (three-times per year) reporting process that Avista has committed to.

The Triple-E Board essentially formalizes the stakeholder involvement process that Avista Corporation has undertaken throughout the 1990s.

**Measurement and Evaluation**

Avista Corporation carries out an on-going measurement and evaluation (M&E) process for all energy efficiency programs. The objective of this process covers not only the traditional measurement of energy savings achieved, but also extends to physical verification of installation, preexistence, implementation process evaluations, and accounting reviews.

Organizationally the M&E analysis is performed independent of the DSM implementation group (i.e., the Energy Services Department) by the Avista Utilities Controllers Department. This independent review has been effective at proactively addressing issues regarding the implementation of energy efficiency programs and projects. This extends not only to the measurement of energy savings, but also to implementation process, regulatory compliance, strategic direction, accounting, and other issues.

**Cost-Effectiveness Analysis**

Cost-effectiveness of the energy efficiency programs is a major criteria for performance under the Tariff Rider. Avista is currently undertaking significant new efforts to more accurately quantify, or at least identify, the non-energy savings and customer costs of 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-effective 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.

# Triple-E Report
# April 1, 2000 to July 31, 2000

Avista Utilities
Customer Solutions Department
Renee Coelho
John Dunlap
Jason Fletcher
Jon Powell

# Table of Contents

## 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[1] | M&E | TOTAL |
|---|---|---|---|---|
| **SEGMENTS** | | | | |
| 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[2] | $ 56,721 | $ 105,580 | $ 883 | $ 163,184 |
| Retail | $ 11,504 | $ 12,686 | $ 2,986 | $ 27,177 |
| **GENERAL** | | | | |
| General (Implementation) | $ 624,022 | $ - | $ - | $ 624,022 |
| General (M&E) | $ - | $ - | $ 56,669 | $ 56,669 |
| **OTHER EXPENDITURES** | | | | |
| NEEA[3] | $ 2,793 | $ 375,577 | $ - | $ 378,370 |
| Leases[4] | $ 26,249 | $ - | $ - | $ 26,249 |
| **OLD PROGRAMS** | | | | |
| LED Traffic Signals | $ - | $ 3,120 | $ - | $ 3,120 |
| New Technologies | $ 373 | $ 27,169 | $ - | $ 27,543 |
| Prescriptive HVAC | $ - | $ - | $ - | $ - |
| Prescriptive Lighting | $ - | $ 1,440 | $ - | $ 1,440 |
| RMPP | $ - | $ - | $ - | $ - |
| Site Specific | $ 3,053 | $ 112,622 | $ - | $ 115,675 |
| SS-VFD | $ - | $ 35,577 | $ - | $ 35,577 |
| Trade Ally | $ 345 | $ (4,930) | $ - | $ (4,585) |
| **TOTAL** | **$ 1,066,145** | **$ 1,562,724** | **$ 92,361** | **$ 2,721,230** |
| **BROKEN OUT BY CATEGORY** | | | | |
| 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 |
| **TOTAL** | **$ 1,066,145** | **$ 1,562,724** | **$ 92,361** | **$ 2,721,230** |
| **CATEGORY AS A PERCENT** | | | | |
| 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% |
| **TOTAL** | **39.2%** | **57.4%** | **3.4%** | **100.0%** |

**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 impl cost [G] | Old pgm alloc M&E cost [H] | Total old pgm non-incent allocations [I] | TOTAL IMPL [J] | TOTAL M&E [K] | TOTAL INCENTIVE [L] | GRAND TOTAL [M] | Allocated ovhd as % of total [N] |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 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.[illegible] |
| Limited Income | $ 11,328 | $ - | $ 11,328 | $ 24,001 | $ 10,303 | $ 34,304 | $ - | $ - | $ - | $ 35,329 | $ 10,303 | $ 365,504 | $ 411,136 | 8.[illegible] |
| 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% |
| | **$ 409,310** | **$ 35,692** | **$ 445,002** | **$ 624,022** | **$ 56,669** | **$ 680,691** | **$ 3,771** | **$ -** | **$ 3,771** | **$ 1,037,104** | **$ 92,361** | **$ 1,189,562** | **$ 2,319,026** | |

[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 | $ 19,698 | $ - | $ - | $ 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% |
| TOTAL $ | $ 192,469 | $ - | $ 47,309 | $ 420,983 | $ 640,854 | $ 207,590 | $ 426,206 | $ 32,129 | $ 24,657 | $ 198,827 | $ - | $ 74,702 | $ 48,785 | $ 4,514 | $ 2,319,026 | 100.0% |
| % of portfolio | 8.3% | 0.0% | 2.0% | 18.2% | 27.6% | 9.0% | 18.4% | 1.4% | 1.1% | 8.6% | 0.0% | 3.2% | 2.1% | 0.2% | 100.0% | |

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 | $ - | $ 4,699 | $ 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% |
| TOTAL $ | $ 116,194 | $ - | $ 18,026 | $273,893 | $387,934 | $ 136,473 | $121,458 | $ - | $ 6,297 | $ 111,818 | $ - | $ - | $17,470 | $ - | $1,189,562 | 100.0% |
| % 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% |
| TOTAL kWh | 1,140,053 | - | 833,442 | 5,213,382 | 4,438,737 | 2,265,250 | 1,852,266 | - | 85,375 | 1,021,059 | - | 62,007 | 40,626 | - | 16,952,196 | 100.0% |
| % of portfolio | 6.7% | 0.0% | 4.9% | 30.8% | 26.2% | 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 Therms | % of Portfolio |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Agricultural | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 0.0% |
| Government | - | - | - | 37,739 | (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 | - | - | - | - | - | - | - | - | - | - | - | - | 13,226 | - | 13,226 | -8.0% |
| Residential | (19,633) | - | - | - | (76,402) | - | - | - | - | - | - | - | - | - | (96,034) | 57.9% |
| Retail | - | - | - | - | - | - | 422 | - | - | - | - | - | - | - | 422 | -0.3% |
| TOTAL Therms | (43,853) | - | - | 45,351 | (129,463) | 1,275 | (10,123) | - | - | - | - | (41,038) | 12,029 | - | (165,821) | 100.0% |
| % 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 |
| Limited Income | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 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% |
| TOTAL NEB $ | - | - | - | 62,775 | - | 1,149,655 | 217,949 | - | - | 251,297 | - | - | 319,986 | - | 2,001,662 | 100.0% |
| % 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 | - | - | - | - | - | - | - | 16,461 | - | 365,504 | 12.4 |
| Manufacturing | - | - | 51,359 | 5,895 | 7,775 | 301,582 | 4,013 | - | - | 394 | - | - | - | - | 371,018 | 12. |
| 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) | - | - | - | - | - | - | - | 30,708 | 1.0% |
| TOTAL NEB $ | 266,360 | - | 51,359 | 608,536 | 875,608 | 301,582 | 405,340 | - | 44,117 | 269,179 | - | - | 115,623 | - | 2,937,703 | 100.0% |
| % 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 Cost Test | Utility Cost Test | Participant Test | Non-Participant Test |
|---|---|---|---|---|
| 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 |
| **PORTFOLIO** | **1.27** | **1.36** | **4.89** | **0.39** |

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

| | Total Resource Cost Test | Utility Cost Test | Participant Test | Non-Participant Test |
|---|---|---|---|---|
| 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 | - |
| **PORTFOLIO** | **1.27** | **1.36** | **4.89** | **0.39** |

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) |
| **PORTFOLIO** | **$ 1,092,087** | **$ 838,567** | **$ 6,791,747** | **$ (5,981,040)** |

**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) |
| **PORTFOLIO** | **$ 1,092,087** | **$ 838,567** | **$ 6,791,747** | **$ (5,981,040)** |

**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

| Total Resource Cost Test | Regular Income portfolio | Limited Income portfolio | Overall portfolio |
|---|---|---|---|
| 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) |
| TRC benefits | $ 4,979,974 | $ 179,281 | $ 5,159,255 |
| Non-incentive utility cost | $ 1,083,832 | $ 45,632 | $ 1,129,464 |
| Customer cost | $ 2,572,199 | $ 365,504 | $ 2,937,703 |
| TRC costs | $ 3,656,031 | $ 411,136 | $ 4,067,167 |
| **TRC ratio** | **1.36** | **0.44** | **1.27** |
| **Net TRC benefits** | **$ 1,323,943** | **$ (231,855)** | **$ 1,092,087** |

| Utility Cost Test | Regular Income portfolio | Limited Income portfolio | Overall portfolio |
|---|---|---|---|
| Electric avoided cost | $ 3,266,327 | $ 532,751 | $ 3,799,079 |
| Natural Gas avoided cost | $ (288,016) | $ (353,470) | $ (641,486) |
| UCT benefits | $ 2,978,312 | $ 179,281 | $ 3,157,593 |
| Non-incentive utility cost | $ 1,083,832 | $ 45,632 | $ 1,129,464 |
| Incentive cost | $ 824,057 | $ 365,504 | $ 1,189,562 |
| UCT costs | $ 1,907,890 | $ 411,136 | $ 2,319,026 |
| **UCT ratio** | **1.56** | **0.44** | **1.36** |
| **Net UCT benefits** | **$ 1,070,422** | **$ (231,855)** | **$ 838,567** |

| Participant Test | Regular Income portfolio | Limited Income portfolio | Overall portfolio |
|---|---|---|---|
| Bill Reduction | $ 5,679,957 | $ 858,269 | $ 6,538,227 |
| Non-Energy benefits | $ 2,001,662 | $ - | $ 2,001,662 |
| Participant benefits | $ 7,681,619 | $ 858,269 | $ 8,539,889 |
| Customer project cost | $ 2,572,199 | $ 365,504 | $ 2,937,703 |
| Incentive received | $ 824,057 | $ 365,504 | $ 1,189,562 |
| Participant costs | $ 1,748,141 | $ - | $ 1,748,141 |
| **Participant Test ratio** | **4.39** | **N/A** | **4.89** |
| **Net Participant benefits** | **$ 5,933,478** | **$ 858,269** | **$ 6,791,747** |

| Non-Participant Test | Regular Income portfolio | Limited Income portfolio | Overall portfolio |
|---|---|---|---|
| Electric avoided cost savings | $ 3,266,327 | $ 532,751 | $ 3,799,079 |
| Non-Part benefits | $ 3,266,327 | $ 532,751 | $ 3,799,079 |
| Revenue loss | $ 6,125,922 | $ 1,335,171 | $ 7,461,092 |
| Non-incentive utility cost | $ 1,083,832 | $ 45,632 | $ 1,129,464 |
| Customer incentives | $ 824,057 | $ 365,504 | $ 1,189,562 |
| Non-Part costs | $ 8,033,811 | $ 1,746,307 | $ 9,780,118 |
| **Non-Part. ratio** | **0.41** | **0.31** | **0.39** |
| **Net Non-Part. benefits** | **$ (4,767,484)** | **$ (1,213,556)** | **$ (5,981,040)** |

| Descriptive Statistics | Regular Income portfolio | Limited Income portfolio | Overall portfolio |
|---|---|---|---|
| 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 DSM Expenditures | Washington DSM Revenues | Washington Beginning DSM balance | Washington Ending DSM balance | Washington interest | Washington Ending bal. with interest |
|---|---|---|---|---|---|---|
| January 1999 | $ 171,037 | $ 371,658 | $ 2,617,016 | $ 2,817,637 | $ 10,950 | $ 2,828,586 |
| February | $ 188,863 | $ 321,493 | $ 2,828,586 | $ 2,961,216 | $ 21,668 | $ 2,982,885 |
| March | $ 416,803 | $ 292,771 | $ 2,982,885 | $ 2,858,853 | $ 23,084 | $ 2,881,937 |
| April | $ 781,855 | $ 266,606 | $ 2,881,937 | $ 2,366,688 | $ 23,291 | $ 2,389,979 |
| May | $ 333,268 | $ 247,454 | $ 2,389,979 | $ 2,304,165 | $ 20,927 | $ 2,325,092 |
| June | $ 283,079 | $ 266,981 | $ 2,325,092 | $ 2,308,994 | $ 18,716 | $ 2,327,710 |
| July | $ 315,854 | $ 237,115 | $ 2,327,710 | $ 2,248,971 | $ 18,476 | $ 2,267,447 |
| August | $ 470,627 | $ 272,035 | $ 2,267,447 | $ 2,068,855 | $ 18,248 | $ 2,087,102 |
| September | $ 220,534 | $ 302,045 | $ 2,087,102 | $ 2,168,613 | $ 17,289 | $ 2,185,903 |
| October | $ 333,763 | $ 260,080 | $ 2,185,903 | $ 2,112,220 | $ 16,968 | $ 2,129,188 |
| November | $ 174,943 | $ 263,916 | $ 2,129,188 | $ 2,218,161 | $ 17,137 | $ 2,235,298 |
| December | $ 759,356 | $ 317,111 | $ 2,235,298 | $ 1,793,053 | $ 17,333 | $ 1,810,386 |
| January 2000 | $ 261,424 | $ 350,395 | $ 1,810,386 | $ 1,899,357 | $ 16,061 | $ 1,915,419 |
| February | $ 296,815 | $ 318,411 | $ 1,915,419 | $ 1,937,014 | $ 14,791 | $ 1,951,805 |
| March | $ 566,151 | $ 296,857 | $ 1,951,805 | $ 1,682,511 | $ 15,360 | $ 1,697,871 |
| 1999 totals | $ 4,449,983 | $ 3,419,265 | | | $ 224,088 | |
| 2000 totals | $ 1,124,390 | $ 965,663 | | | $ 46,212 | |

| Month | Idaho DSM Expenditures | Idaho DSM Revenues | Idaho Beginning DSM balance | Idaho Ending DSM balance | Idaho interest | Idaho Ending bal. with interest |
|---|---|---|---|---|---|---|
| January 1999 | $ 70,147 | $ 161,905 | $ 1,053,579 | $ 1,145,337 | $ 2,385 | $ 1,147,722 |
| February | $ 100,620 | $ 157,171 | $ 1,147,722 | $ 1,204,273 | $ 8,767 | $ 1,213,040 |
| March | $ 57,166 | $ 143,563 | $ 1,213,040 | $ 1,299,438 | $ 9,378 | $ 1,308,815 |
| April | $ 268,935 | $ 132,749 | $ 1,308,815 | $ 1,172,629 | $ 10,017 | $ 1,182,647 |
| May | $ 131,689 | $ 121,686 | $ 1,182,647 | $ 1,172,644 | $ 9,894 | $ 1,182,538 |
| June | $ 87,749 | $ 121,986 | $ 1,182,538 | $ 1,216,775 | $ 9,391 | $ 1,226,165 |
| July | $ 82,662 | $ 121,018 | $ 1,226,165 | $ 1,264,521 | $ 9,566 | $ 1,274,087 |
| August | $ 146,099 | $ 82,983 | $ 1,274,087 | $ 1,210,971 | $ 9,931 | $ 1,220,902 |
| September | $ 85,885 | $ 86,004 | $ 1,220,902 | $ 1,221,021 | $ 9,908 | $ 1,230,929 |
| October | $ 304,545 | $ 81,571 | $ 1,230,929 | $ 1,007,955 | $ 9,736 | $ 1,017,691 |
| November | $ 167,877 | $ 85,391 | $ 1,017,691 | $ 935,206 | $ 8,927 | $ 944,132 |
| December | $ 306,838 | $ 102,257 | $ 944,132 | $ 739,552 | $ 7,786 | $ 747,338 |
| January 2000 | $ 174,092 | $ 93,727 | $ 747,338 | $ 666,973 | $ 6,713 | $ 673,686 |
| February | $ 92,648 | $ 124,369 | $ 673,686 | $ 705,407 | $ 5,639 | $ 711,046 |
| March | $ 200,639 | $ 95,373 | $ 711,046 | $ 605,780 | $ 5,499 | $ 611,278 |
| 1999 totals | $ 1,810,210 | $ 1,398,284 | | | $ 105,685 | |
| 2000 totals | $ 467,379 | $ 313,469 | | | $ 17,850 | |

| Month | Combined DSM Expenditures | Combined DSM Revenues | Combined Beginning DSM balance | Combined Ending DSM balance | Combined interest | Combined Ending bal. with interest |
|---|---|---|---|---|---|---|
| January 1999 | $ 241,185 | $ 533,563 | $ 3,670,595 | $ 3,962,973 | $ 13,335 | $ 3,976,308 |
| February | $ 289,483 | $ 478,664 | $ 3,976,308 | $ 4,165,489 | $ 30,436 | $ 4,195,925 |
| March | $ 473,969 | $ 436,334 | $ 4,195,925 | $ 4,158,290 | $ 32,462 | $ 4,190,752 |
| April | $ 1,050,790 | $ 399,355 | $ 4,190,752 | $ 3,539,317 | $ 33,309 | $ 3,572,626 |
| May | $ 464,956 | $ 369,140 | $ 3,572,626 | $ 3,476,809 | $ 30,820 | $ 3,507,630 |
| June | $ 370,828 | $ 388,967 | $ 3,507,630 | $ 3,525,768 | $ 28,107 | $ 3,553,875 |
| July | $ 398,516 | $ 358,133 | $ 3,553,875 | $ 3,513,492 | $ 28,043 | $ 3,541,534 |
| August | $ 616,726 | $ 355,018 | $ 3,541,534 | $ 3,279,826 | $ 28,178 | $ 3,308,004 |
| September | $ 306,419 | $ 388,049 | $ 3,308,004 | $ 3,389,635 | $ 27,197 | $ 3,416,832 |
| October | $ 638,308 | $ 341,651 | $ 3,416,832 | $ 3,120,175 | $ 26,704 | $ 3,146,879 |
| November | $ 342,820 | $ 349,307 | $ 3,146,879 | $ 3,153,366 | $ 26,064 | $ 3,179,430 |
| December | $ 1,066,194 | $ 419,368 | $ 3,179,430 | $ 2,532,604 | $ 25,120 | $ 2,557,724 |
| January 2000 | $ 435,516 | $ 444,122 | $ 2,557,724 | $ 2,566,330 | $ 22,774 | $ 2,589,105 |
| February | $ 389,463 | $ 442,780 | $ 2,589,105 | $ 2,642,421 | $ 20,430 | $ 2,662,851 |
| March | $ 766,790 | $ 392,230 | $ 2,662,851 | $ 2,288,291 | $ 20,858 | $ 2,309,150 |
| 1999 totals | $ 6,260,193 | $ 4,817,549 | | | $ 329,773 | |
| 2000 YTD totals | $ 1,591,769 | $ 1,279,132 | | | $ 64,063 | |

**DSM balance reduction in most recent twelve months:**

| | Rev - Exp | Exp / Rev | $ balance reduction | % balance reduction | Interest |
|---|---|---|---|---|---|
| Washington | $ (1,398,663) | 141% | $ 1,184,066 | 41% | $ 214,597 |
| Idaho | $ (800,543) | 164% | $ 697,537 | 53% | $ 103,006 |
| System | $ (2,199,206) | 147% | $ 1,881,602 | 45% | $ 317,603 |

**NOTES:**

Interest calculations have been revised to be based upon the prior months 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.

### VendingMI$ER™

As indicated in the last trimester report, Avista is continuing a long-term evaluation of the VendingMI$ER™ 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 reviews

City 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:

| Intersection | Typical Summer Usage | Winter Peak |
|---|---|---|
| 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.

Chart A10 Utility Cost (Cash Basis vs. Cost-Effectiveness Basis)

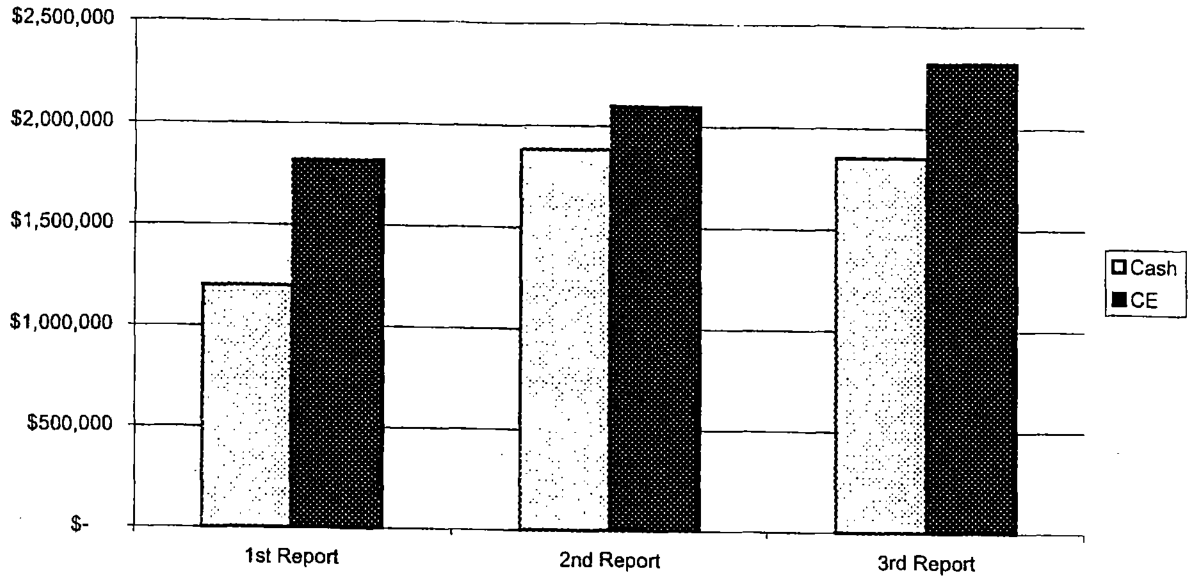
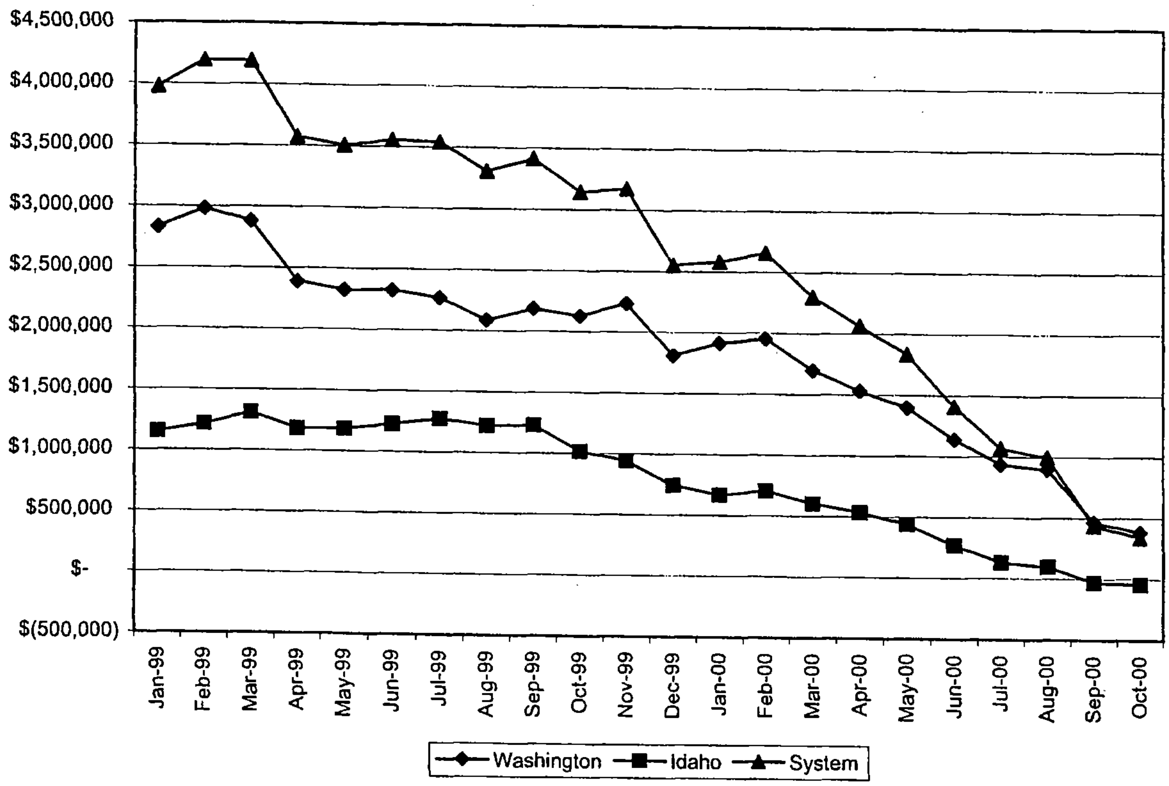



Chart A11 Energy-Efficiency Tariff Rider Balances



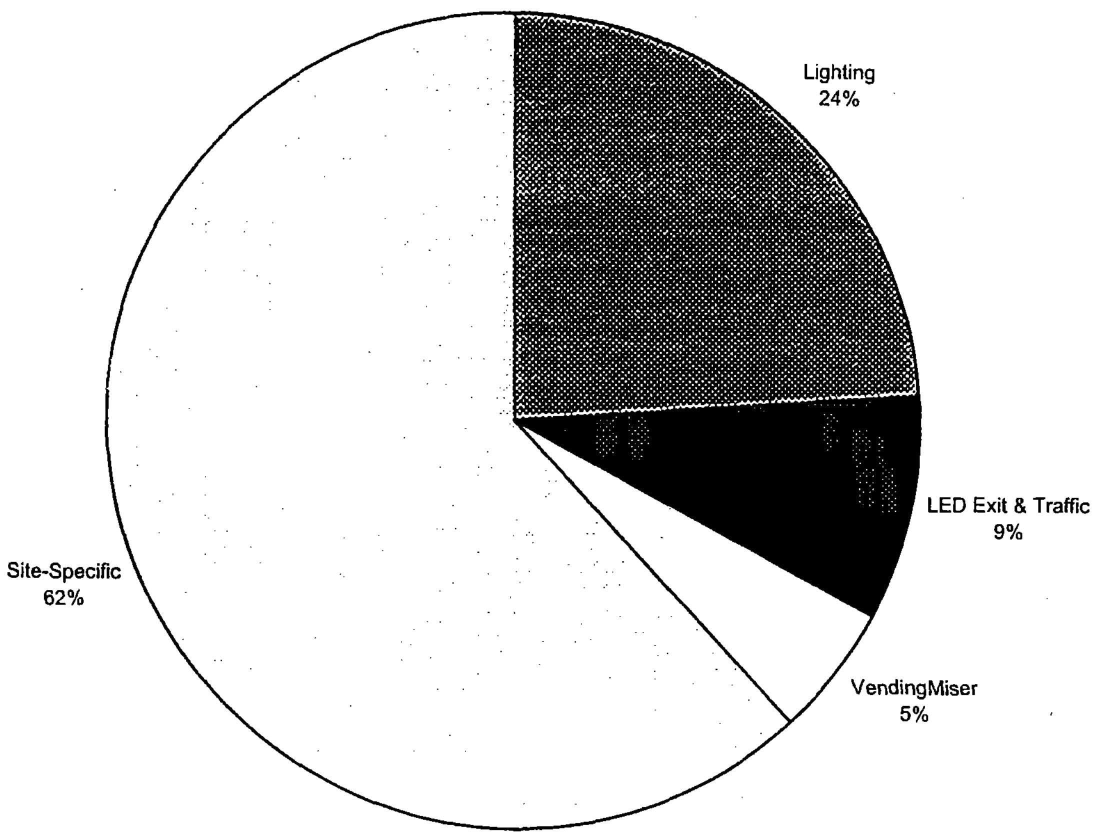
The cost-effectiveness measurement of expenditures is persistently above the cash basis due to the increase in energy savings during this time period. More projects are coming into the pipeline (and being partially realized on an accrual basis for cost-effectiveness purposes) than are being completed (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 A9** Project Breakdown by kWh (2nd and 3rd Reports)



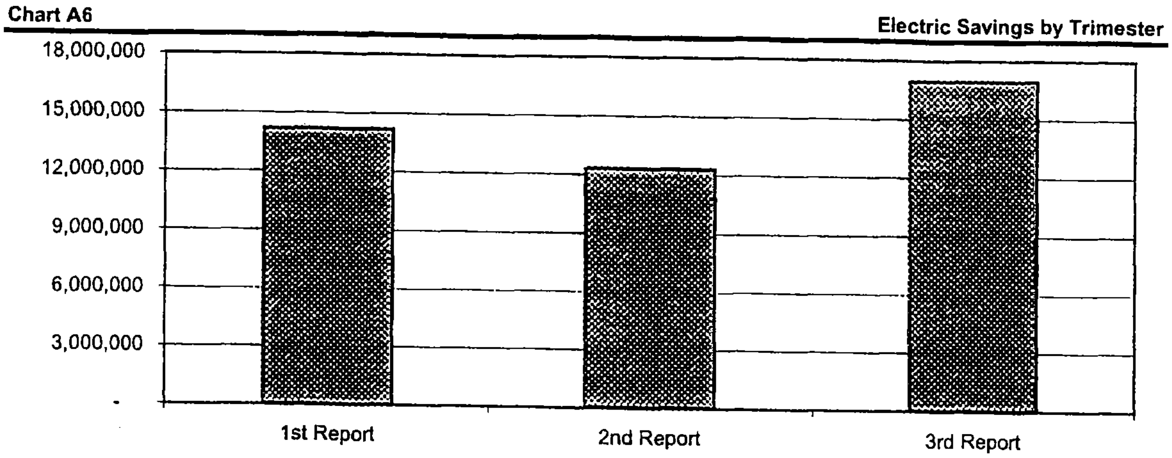


Chart A6
Electric Savings by Trimester
18,000,000
15,000,000
12,000,000
9,000,000
6,000,000
3,000,000
-
1st Report
2nd Report
3rd Report

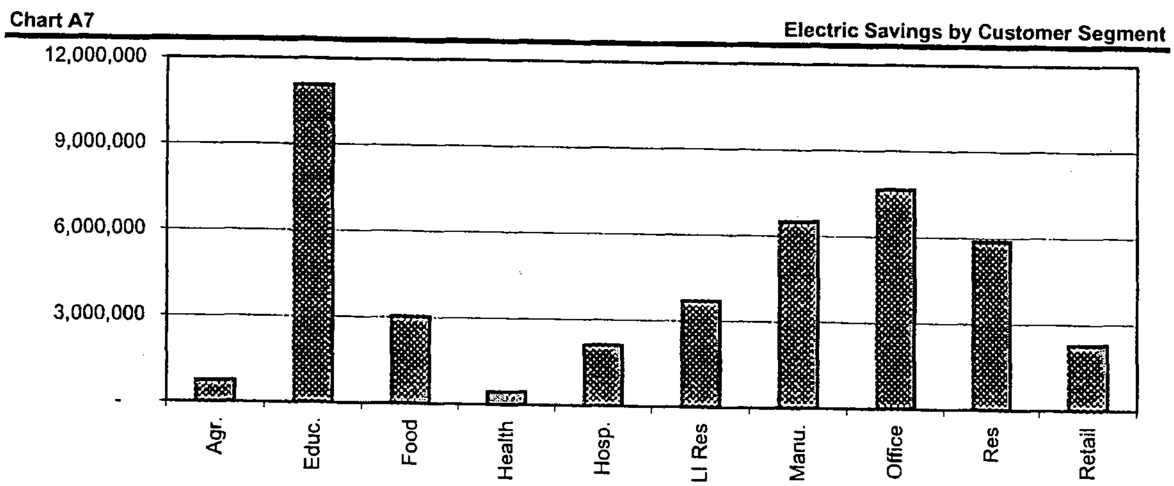


Chart A7
Electric Savings by Customer Segment
12,000,000
9,000,000
6,000,000
3,000,000
-
Agr.
Educ.
Food
Health
Hosp.
LI Res
Manu.
Office
Res
Retail

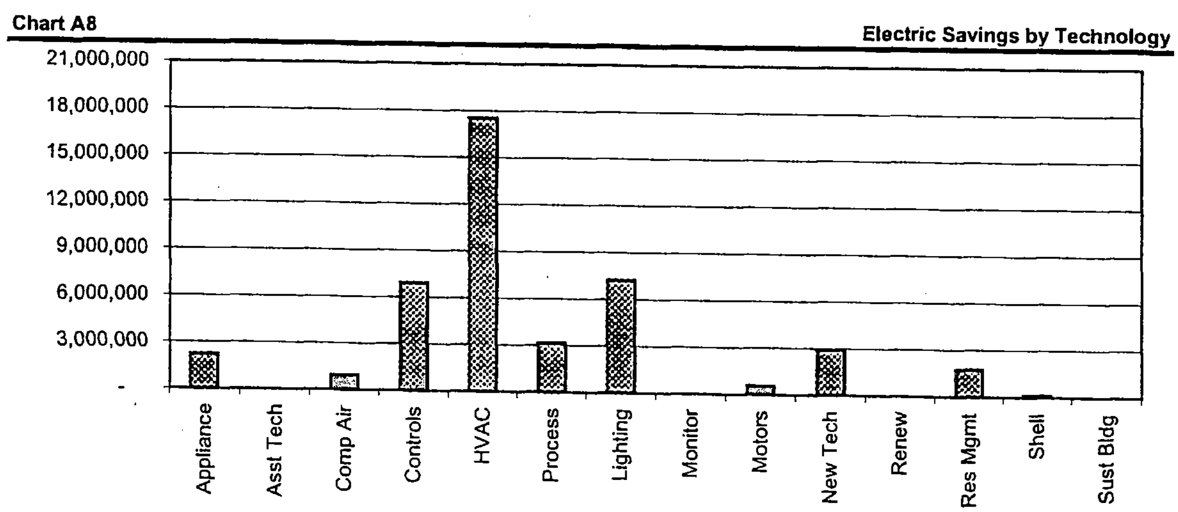


Chart A8
Electric Savings by Technology
21,000,000
18,000,000
15,000,000
12,000,000
9,000,000
6,000,000
3,000,000
-
Appliance
Asst Tech
Comp Air
Controls
HVAC
Process
Lighting
Monitor
Motors
New Tech
Renew
Res Mgmt
Shell
Sust Bldg

The energy-efficiency programs have saved over 43 million 1st 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 A3

TRC Costs

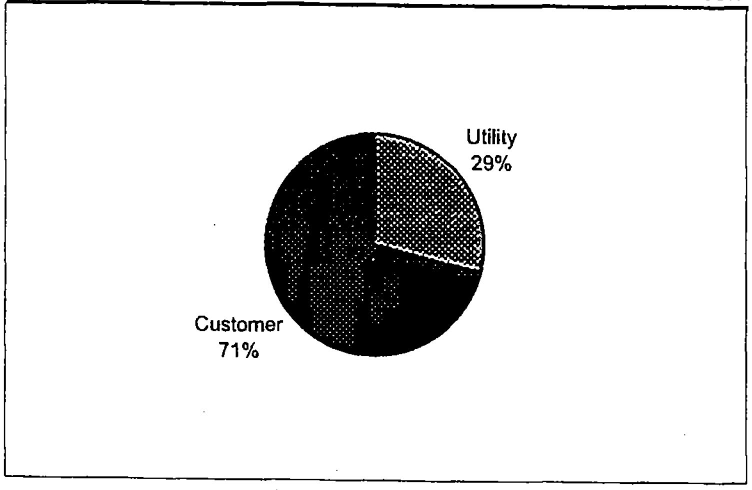



Chart A4

TRC Benefits

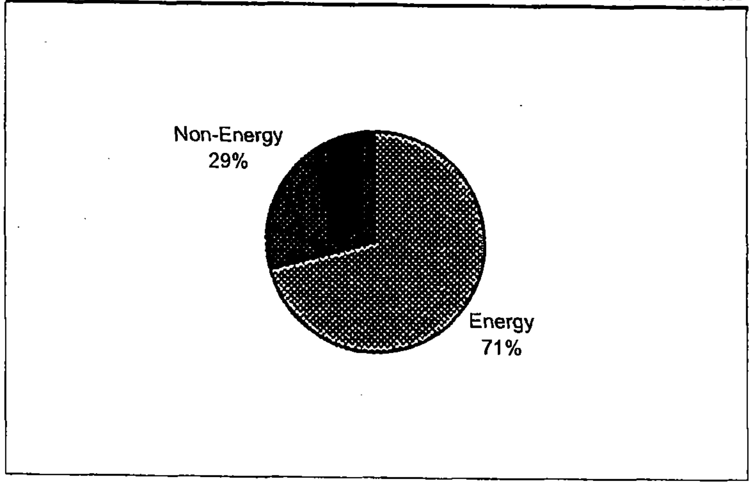
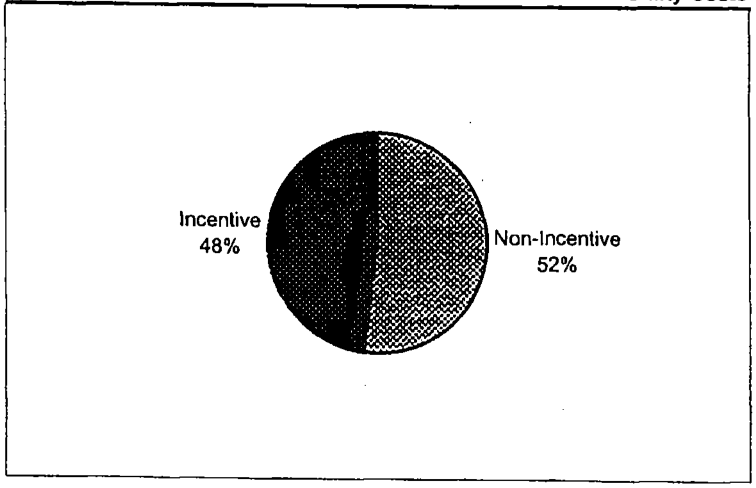



Chart A5

Utility Costs



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.

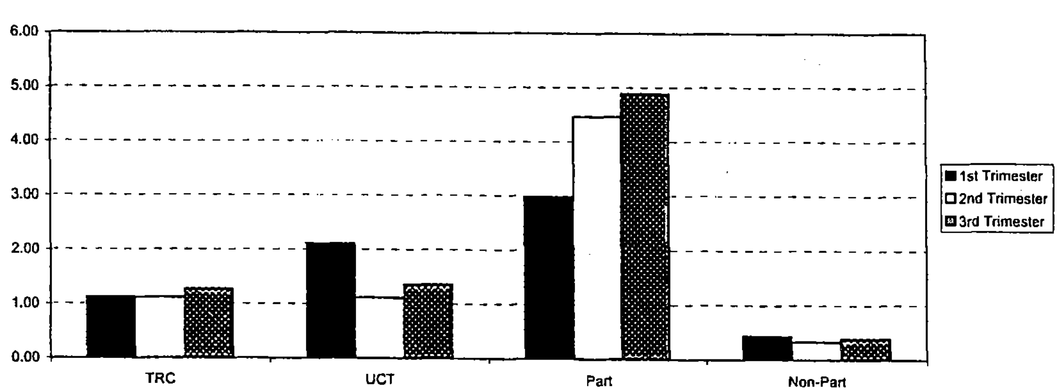
The utility costs are fairly evenly split between incentive and non-incentive costs. The proportion of utility costs going towards incentives has increased with the adoption of the generally higher tiered incentives in the most recent revision of Schedule 90.

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

## 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) | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Total Resource Cost Test** | Reg. Inc. | Lim. Inc. | Portfolio | Reg. Inc. | Lim. Inc. | Portfolio | Reg. Inc. | Lim. Inc. | Portfolio | Reg. Inc. | Lim. Inc. | Portfolio |
| 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) |
| TOTAL TRC BENEFITS | $ 3,521,123 | $ 394,347 | $ 3,915,470 | $ 3,832,506 | $ 463,467 | $ 4,095,973 | $ 4,979,973 | $ 179,281 | $ 5,159,254 | $ 12,133,602 | $ 1,037,095 | $ 13,170,697 |
| 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 |
| TOTAL TRC COSTS | $ 3,178,796 | $ 320,946 | $ 3,499,742 | $ 3,184,093 | $ 509,719 | $ 3,693,812 | $ 3,656,031 | $ 411,136 | $ 4,067,167 | $ 10,018,920 | $ 1,241,801 | $ 11,260,721 |
| 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 |
| **Utility Cost Test** | | | | | | | | | | | | |
| 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) |
| TOTAL UTC BENEFITS | $ 3,444,273 | $ 394,347 | $ 3,838,620 | $ 1,857,045 | $ 463,467 | $ 2,320,512 | $ 2,978,311 | $ 179,281 | $ 3,157,592 | $ 8,279,629 | $ 1,037,095 | $ 9,316,724 |
| 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 |
| TOTAL UTC COSTS | $ 1,500,750 | $ 320,946 | $ 1,821,696 | $ 1,586,991 | $ 509,719 | $ 2,096,710 | $ 1,907,889 | $ 411,136 | $ 2,319,025 | $ 4,995,630 | $ 1,241,801 | $ 6,237,431 |
| 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 |
| **Participant Test** | | | | | | | | | | | | |
| 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 |
| TOTAL PART. BENEFITS | $ 4,547,870 | $ 456,505 | $ 5,004,375 | $ 5,843,034 | $ 1,276,036 | $ 7,119,070 | $ 7,681,619 | $ 858,269 | $ 8,539,888 | $ 18,072,523 | $ 2,590,810 | $ 20,663,333 |
| 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) |
| TOTAL PART. COSTS | $ 1,678,046 | $ - | $ 1,678,046 | $ 1,597,102 | $ - | $ 1,597,102 | $ 1,748,142 | $ - | $ 1,748,142 | $ 5,023,290 | $ - | $ 5,023,290 |
| 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 |
| **Non-Participant (electric) Test** | | | | | | | | | | | | |
| 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 |
| TOTAL NON-PART BENEFITS | $ 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 |
| 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 |
| TOTAL NON-PART COSTS | $ 7,775,241 | $ 940,833 | $ 8,716,074 | $ 6,124,672 | $ 2,045,680 | $ 8,170,352 | $ 8,033,811 | $ 1,746,307 | $ 9,780,118 | $ 21,933,724 | $ 4,732,820 | $ 26,666,544 |
| 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



# 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$^{nd}$ 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*.

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.

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.

- 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.

- 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:

- 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.

<u>Sample New Technologies Business Plan</u>

LED Traffic Lights

<u>Market Barrier</u>:

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

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":

## 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.

<u>New Technology Policy Statement</u>

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**

# 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 b

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

Table B2

Breakdown of All Projects b

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

Table B3

Breakdown of Database Projects b

| 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% |
| **All** | **372** | **100.0%** | **12,822,238** | **100.0%** |

Table B4

Breakdown of All Projects b

| 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% |
| **All** | **638** | **100.0%** | **16,873,309** | **100.0%** |

**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% |
| *Unknown* | *4* | *1.1%* | *396,372* | *3.1%* |
| **All** | **372** | **100.0%** | **12,822,238** | **100.0%** |

**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% |
| *Unknown* | *4* | *0.6%* | *396,372* | *2.3%* |
| **All** | **638** | **100.0%** | **16,873,309** | **100.0%** |

**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% |
| *None/Unknown* | *149* | *40.1%* | *(4,021)* | *-8.9%* |
| **All** | **372** | **100.0%** | **45,378** | **100.0%** |

**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% |
| *None/Unknown* | *149* | 23.4% | *(4,021)* | *2.4%* |
| **All** | **638** | **100.0%** | **(165,821)** | **100.0%** |

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# 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.

January 24, 2001

**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 | 9 | 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 | Snohomish 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 | 1462 | 1982 | 1011 | 2005 | 1018 | 2068 | 1046 | 2124 | 1084 | 2171 | 1111 | 2227 | 1142 | 2285 | 1176 | 2347 | 1210 |
| | RESOURCES | | | | | | | | | | | | | | | | | | | | |
| 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 | 69 | 140 | 48 | 140 | 48 | 140 | 48 | 140 | 42 |
| 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 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 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 | 72 | 149 | 149 | 149 | 149 | 149 | 149 |
| 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 |