DAVID J. MEYER
SENIOR VICE PRESIDENT AND GENERAL COUNSEL
AVISTA CORPORATION
P.O. BOX 3727
1411 EAST MISSION AVENUE
SPOKANE, WASHINGTON 99220-3727
TELEPHONE: (509) 495-4316
FACSIMILE: (509) 495-4361

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	CASE NO. AVU-E-04-01
OF AVISTA CORPORATION FOR THE	)	
AUTHORITY TO INCREASE ITS RATES	)	
AND CHARGES FOR ELECTRIC AND	)	
NATURAL GAS SERVICE TO ELECTRIC AND	)	EXHIBIT NO. 6
NATURAL GAS CUSTOMERS IN THE STATE	)	
OF IDAHO	)	ROBERT J. LAFFERTY
	)	

FOR AVISTA CORPORTATION

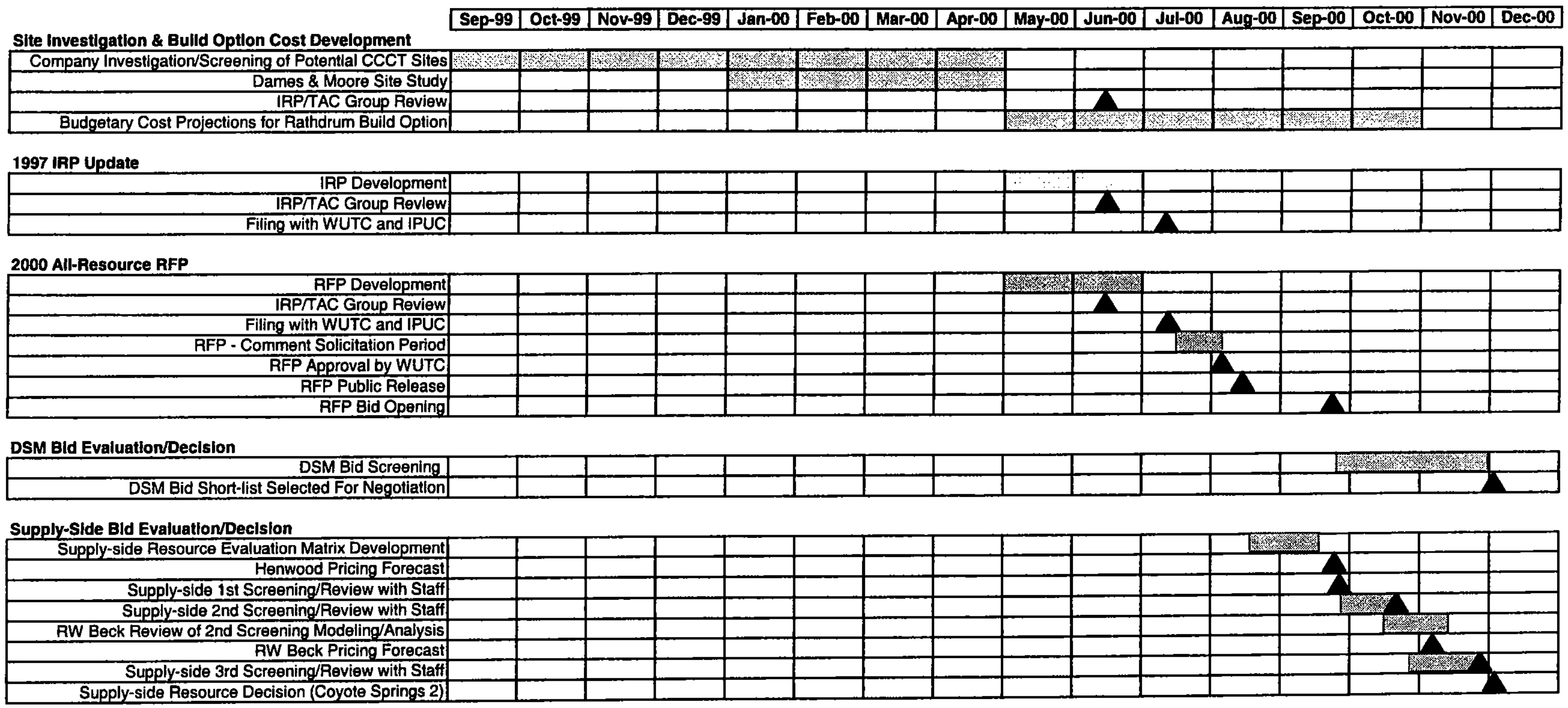
(ELECTRIC ONLY)

(SCHEDULES 4, 7, 9, 10, 11, 12, 14 & 15 OF THIS EXHIBIT ARE CONFIDENTIAL)

CASE NO. AVU-E-04-01

EXHIBIT NO. 6
TABLE OF CONTENTS

2000 Resource Acquisition Process - Timeline



Exh. 6 / Schedule 1
R. Lafferty
Avista Corporation

AVISTA CORP
2000 RESOURCE SELECTION PROCESS REPORT

February 14, 2001

The following report outlines the resource planning, data gathering, evaluation and selection process that has been a focus of a concentrated work effort by Avista Corp staff and others outside of the Company. The intent of the report is to provide an overview of the entire selection process. Avista has extensive documentation records that were kept throughout the work effort. Those records are available to provide the details supporting the decisions that were made by the Company. Many of those records contain confidential bids and proprietary analysis done by third parties. Certain information is therefore intentionally kept general in this report to avoid inappropriate disclosure.

Planning & Determination of Resource Need

Fall 1998 Through Spring 2000 — **Centralia Sale**

- On October 30, 1998, the Centralia owners approved moving forward with a plan to put the entire generating plant and mine up for sale.
- In November 1998, the Centralia plant was put up for formal bidding.
- On May 7, 1999, the Centralia TECWA was selected as the winning bidder. The mine owners executed a sale agreement with TECWA dependant on obtaining board and regulatory approvals and upon resolution of several other plant and mine related issues.
- On May 5, 2000, the Centralia power plant was sold to TECWA by the joint owners.

Fall 1999 — **Medium-Term Power Purchase**

- In October 1999, the Company contracted with TECWA for 200MW of capacity and energy for Q1, Q2, and Q4 contingent on the sale of the plant and continuing through 12/31/03. A contingent purchase was most beneficial due to the real uncertainty as to whether all of the sale contingencies could be worked through satisfactorily.

Fall 1999 Through Spring 2000 — **Resource Site Option Investigation**

- The Company began meetings in August to discuss resource projects in the Pacific Northwest region that were felt to be possible long-term resource candidates. A list of likely sites in the region was made. All of the projects were combined cycle natural gas combustion turbine sites.
- From September through November, a total of 32 project sites were visited. Information was collected regarding permitting status, construction schedules, potential costs, unique issues, etc. Air permit issues, water source issues, water discharge issues, community support issues, electric transmission, natural gas transmission, etc. were part of the data gathered from the different meetings and visits. The company considered the prospect of a project consisting of either

one or two combined cycle combustion turbines. The assumption was that a two-unit project would be a partnership arrangement where a third-party would take on the obligations of the second unit. Both parties would share in the economies of scale that occur when two units are managed together at one location. Alternatively, the second unit could still be built at a later date.

Avista CCCT Initial Siting Study [CCCT Turbine Site Study – Book #2]

- November through December, company staff processed through information gathered on different sites in a series of meetings. Sites with significant roadblocks were eliminated through a group review process. Five sites were selected for further evaluation and study. Those sites were: Rathdrum, Idaho (at the current simple cycle project location); Kaiser Mead; Hermiston, Oregon; Starbuck, Washington; Vanalco (near Vancouver, WA).
- In January 2000, the company contracted with Dames & Moore to perform a more thorough site evaluation on those project sites identified. Some of the evaluation areas were air permit issues, water source issues, water discharge issues, noise issues, etc. The consultant was asked to consider issues and suitability of the site relative to place either one 250MW combined cycle turbine or two 250MW combined cycle turbines (500MW total) at each of the sites. The relative benefits of one project site over another can change depending on whether one or two combined cycle turbines are planned. The company wanted these differences identified.

"Pacific Northwest Combined Cycle Combustion Turbine Generation Facility Siting Study" [CCCT Turbine Site Study – Book #2]

- April 2000 saw the completion of the Dames & Moore project site study. Rathdrum was the top ranked project site for a single combined cycle turbine. Kaiser-Mead ranked as a top project site for a two unit project.
- The Dames & Moore study was reviewed with the IRP TAC group on 6/22/00.

Spring 2000 **Updated Resource Plan/Criteria**

- The company reviewed various planning issues along with updating the company's Load & Resource tabulation showing the removal of its share of the output from Centralia in mid-year 2000. One planning factor that was changed was the degree to which the company would plan to rely on the short-term market to meet load obligations. However, as prices continued to rise in the late spring of 2000, the company concluded that it should reduce its reliance on the short-term market to meet planned resource requirements. The L&R showed over 300aMW of need in 2004. A similar amount of annual capacity need was also shown.
- In addition to looking at annual capacity and energy L&R positions, the company also looked at the month by month L&R position during on-peak and off-peak times. The company reviewed its position monthly over several years. Again, 2004 showed significant deficits and therefore would be the focus of future discussions regarding the

company's resource need.

WUTC & IPUC staff meetings. [Planning-Need Book #3]

- The company met with the WUTC staff on 5/23/00 and the IPUC staff and commissioners on 6/2/00. The purpose of those meetings was to review the company's Load & Resource tabulation, the size and timing of resource need, the types of resource options, and the process or steps that the company should take to select resources for filling the identified needs. The company laid out some general concepts for the all-resource RFP. The company also developed and presented "deficiency duration curves" showing the percent of time that the company would be deficient a certain amount of power using the Prosym hourly dispatch model and 60 years of hydro data. The area under the curve gives a good general indication of the amount of energy needed to meet resource requirements. (Peaking plants were removed from the resource stack in this presentation of data, and then they were shown added back to show how they fit peak needs.) A base load resource, such as a combined cycle combustion turbine, was shown to fit the deficiency gap.
- The company began work on a 1997 Integrated Resource Plan Update at the suggestion of the WUTC staff. We discussed that it was most expedient to file an update of an already filed and accepted plan in order to get an official acceptance of resource need from the commission. The other alternative would have been to file the IRP that was in progress. This would have taken much longer to get commission review and acceptance. The company proceeded to address key areas of the plan, identified by WUTC staff, that would require updating.

Spring 2000 Updated 1997 IRP

- The IRP is a long-term planning tool used to determine Avista's energy and capacity balance for a ten-year period. The IRP itemizes Avista's peak and average loads, firm contract resources and obligations, and power plant energy production and capacity (under critical water conditions) on an annual basis. Netting these numbers illustrates Avista's annual surplus or deficit energy and capacity position to serve native load.
- Due to changes in the native load forecast, changes in power plant ownership, and changes in long-term firm contract resources and obligations it was necessary to revise the 1997 IRP to show the most current load and resource position. The IRP was revised and submitted to the WUTC on July 12, 2000. The IRP shows Avista deficit in load and resource balance through 2003 under critical water conditions. In 2004 and beyond, the IRP shows Avista requiring up to 300 MW of energy and capacity to meet native load requirements.
- Avista used the 2000 Gas IRP as a starting point for the 1997 IRP Update electric price forecast. It is reasonable to assume that a new generation combined cycle combustion turbine is the likely marginal

resource of the future. Applying historical spark spreads to quantify a possible electric forecast is a reasonable method to show how a new resource may fair under different market conditions.

June/July 2000 **IRP/RFP Review**

IRP Technical Advisory Team Meeting [Planning-Need Book #3]

- Because of the need for substantial long-term resources, the company developed drafts of an all-resource request for proposals (RFP). The company developed a draft RFP during May and June 2000.
- On 6-22-00, company staff reviewed the basic components of the 1997 IRP Update with the IRP Technical Advisory Committee (TAC) in Spokane. WUTC staff, IPUC staff, Northwest Energy Coalition, and Northwest Energy Services were in attendance at the meeting and provided some comments. Company staff reviewed the Prosym hourly dispatch model that was being used to evaluate resource options. The Company's natural gas and electric price forecasts were discussed. The company also shared draft copies of the proposed all-resource RFP. The RFP would assess options available in the market to compare to its own company sponsored projects. Company staff also made a presentation regarding the company's new resource site investigation process including the Dames & Moore site investigation study.
- The company followed up with WUTC staff, IPUC staff, Washington State Public Council, Industrial Customers of Northwest Utilities, Washington Dept. of Community, Trade and Economic Development, and Northwest Energy Coalition to get comments on both the 1997 IRP Update and the proposed RFP. Various comments were received and worked through. The company shared ProSym model run data showing how the Avista resources would be modeled with commission staff.

July/August 2000 **IRP/RFP Approvals**

IRP and RFP Filed With WUTC & IPUC [Planning-Need Book #3]

- On July 12, 2000, the 1997 IRP Update (IRP) was filed with both commissions to supplement the Company's previous plan filed pursuant to WAC 480-100-251 in Washington and by Idaho Order No. 22299. The RFP filings were based on the Company's IRP. As described in the preceding sections, Avista's revised loads and resources demonstrated a need for power.
- Avista Corp filed its Request For Proposals (RFP) with the WUTC on July 13, 2000 and with the IPUC on July 12, 2000. The RFP indicated that the company was seeking proposals for approximately 300 MW of capacity and energy and that flexibility/dispatchability of a resource was a preference. Proposals were sought on all resource types. Renewable resources were given a 10% price credit.
- The RFP was filed pursuant to the WUTC's rule requiring solicitation of competitive bids under WAC 480-107. The Company

opted to file identical copies with IPUC for purposes of keeping the Idaho Commission abreast of resource procurement issues on the same timeline.

- The Company met with Commission Staffs prior to each filing as described in preceding sections. These meetings, in combination with Avista's June IRP Technical Advisory Committee meeting, allowed the Company to gain stakeholder input prior to the release of the RFP.
- On July 12, 2000, the company mailed copies of the filed RFP to 22 potential bidders or interested parties for their review and comment.
- On July 18, 2000, the WUTC formally noticed the filing of Avista's RFP and requested comments by August 8, 2000.
- On July 21, 2000, the IPUC formally noticed Avista's RFP and requested comments by August 11, 2000.
- On August 2, 2000, company representatives met with IPUC staff and Commissioners in Boise to review the 1997 IRP Update and the RFP and to respond to questions.

RFP Approved by WUTC and recognized by IPUC. [Planning-Need Book #4]

- On August 9, 2000, the WUTC heard commission staff, intervenor and company comments on Avista's all-resource RFP. The WUTC Commission Staff developed a memorandum supporting both the need for resources identified in the 1997 IRP Update and the RFP. The WUTC approved the RFP in Docket NO. UE-001081.
- IPUC staff issued their recommendations on August 11th noting that issuance of the RFP was an appropriate action. On October 10th, the IPUC issued Order No. 28542 regarding the RFP, in Case NO. AVU-E-08 noting that approval is not necessary. The IPUC stated "the Company is commended for soliciting public input into its RFP process."
- As an ongoing process, the Company agreed, as part of the Commission approvals, to provide the Staffs access to all materials needed to review the final evaluation system before the bids were opened. Further, the Company committed to sharing all modeling and analysis with the Staffs for the purpose of verifying the final selections.
- The RFP was released to the public on August 14, 2000. The RFP and the 1997 IRP Update were published on Avista's web-site. An announcement was posted in newspapers in Spokane, Seattle and Portland. Media was contacted and interviews were conducted regarding the Company's need for resources and the RFP. The company asked for bids to be returned by September 18, 2000.

Evaluation and Decision-Supply Side

Sept.- 2000 **Supply-Side Evaluation Matrix Development**

- Avista determined that a first screening would ensure that bid proposals met required criteria as stated in the RFP. Bidders were to provide general qualifications as outlined in the RFP plus the project specific information requested for each proposal submitted.
- The RFP document laid out the three principle areas that would be the focus of further evaluation: Electric power characteristics; finance/price characteristics; and social/environmental characteristics. The company had committed to commission staff to develop a more detailed evaluation matrix based on the principle areas prior to the opening of RFP bid proposals.
- The company developed a set of financial/price and non-price factors with associated weightings. This evaluation matrix and write-up describing the various weightings and the ranking process was reviewed with WUTC and IPUC staff members on September 13, 2000.

Review RFP Evaluation Process with WUTC/IPUC staff [Planning-Need Book #4]

Financial/Price Factors

- To provide a consistent evaluation framework, the Screening Work Group developed a matrix to evaluate all supply-side proposals against. The matrix contained the categories of Financial/Price Evaluation Factors, and Non-Price Evaluation Factors. Financial/Price factors received a 65% total weighting. Within this category, three sub-categories, and their weightings, were assigned. The Financial/Price Factors were: economic benefits (35%); financial performance capability (15%); and fuel price risk (15%).
- Economic benefits assessed the net savings, on a per-MWh basis, that each proposal brought to the Company's resource portfolio.
- Financial Performance Capability assessed the likelihood that the bidder had the financial ability to complete the proposed project.
- Fuel Price Risk quantified the potential for the price of the proposal's fuel source to change significantly. For example, flat purchase contracts that were not tied to the price of an underlying fuel source rated highly. Projects consuming natural gas received a lower rating.

Non-Price Evaluation Factors

- Non-Price Evaluation Factors received a 35% total weighting. In each category, sub-categories and weightings were assigned. Within the Non-Price Evaluation Factors were: fuel availability risk (5%); Electric Factors (20%); and Environmental Factors (10%).
- Fuel Availability Risk assessed the availability of supply and any risks associated with delivery of the fuel.
- Electric Factors provided an area to evaluate such characteristics as ramping rates, dispatchability, reactive supply, the supply source, and system integration.

- Environmental Factors were designed to ensure adequate permits were available, that environmental laws and regulations were adhered to, and proven technology was used to meet such laws and regulations.

September 2000

Henwood Pricing Forecast [Eval.- Decision Book #2]

Pricing Study – Henwood Energy Services, Inc

- Under contract with Avista, Henwood Energy Services, Inc. (HESI) delivered a WSCC Regional Market Price Forecast study on September 22, 2000. The price forecast included monthly heavy and light load electricity prices and annual gas prices (later updated to monthly gas prices) for the years 2001 – 2022. The wholesale electric and natural gas price forecast was derived from HESI's proprietary *Prosym*™ and Electric Market Simulation System software. [*Prosym*™ performs detailed fundamental simulation of the electric wholesale market on an hour-to-hour basis. Electric production is modeled at the generation unit level while system loads and transmission constraints are modeled on an hourly basis. *Prosym*™ computes market clearing prices and generation production for user-defined transmission zones.]

- As a third party source with recognized expertise in electric and natural gas forecasting, Avista used HESI's electric and natural gas forecast as the source for the second screen RFP economic evaluation process.

- The base electric price forecast was subject to many market variables. Plant availability, plant additions, gas prices, hydro conditions, load growth, and transmission constraints could all affect the future price of wholesale electricity. HESI provided a report (dated September 22, 2000) and a supplemental report (dated December 21, 2000) detailing assumptions made in the electric and natural gas price forecast.

Development Of High and Low Electric Price Scenarios:

- To illustrate the impact of different levels of new capacity additions in the WSCC on wholesale electricity prices, HESI performed an electric price scenario analysis for the period 2001 through 2005. In the underbuild scenario, 9,000 MW of new generation (only capacity that was under construction as of August 2000) comes on line in the WSCC during the 2001-2005 period. The overbuild scenario was simulated by including 23,000 MW of new generation in the WSCC with announced commercial operation dates before 2005. This represents roughly 44 percent of known announced generation in the WSCC. Natural gas prices were assumed to be the same as the base case.

- To quantify a reasonable spread of potential longer term high and low electric price scenarios, Avista used HESI's scenario analysis as a starting point. A paper by Professor Andrew Ford of Washington State University discusses cycles in the electric industry due to overbuilding and underbuilding electric plant. Avista used the frequency interval (7 years) between periods of peak over or under building from Dr. Ford combined with the amplitude of the electric price from the HESI over or under build scenarios to extrapolate a high and a low price forecast through the year 2025. . After discussion with Commission staff, Avista finalized the high/low electric price forecast scenarios by smoothing the over/underbuild data to represent a high and low price forecast.

- The Company extended the price forecasts through 2025 using the growth rate between 2021 and 2022 to meet the need for a forecast of 25-year duration.

September 2000

Prosym Analysis Methodology

- Prosym is commercially available production cost modeling tool that optimizes hourly dispatch of company owned or contract generation resources against load requirements, gas and electric price information, and supply or requirements contracts. Avista used *Prosym*™ to estimate costs and benefits to Avista's utility system of the RFP bids and the self-build option.
- The resulting model output quantifies how each RFP bid or self-build resource option meets the hourly requirements of Avista's electric system with the least production cost.
- Models of Avista's system included on-peak and off-peak loads, hydroelectric and thermal generating resources, contractual sales and purchases, and spot-market sales and purchases
- The model was run without proposed resource options and then with each resource proposal individually to determine the net benefit of each resource option to the company.

September 2000

Economic Analysis/Revenue Requirements Modeling

- All proposals entering at least the second screening were to be evaluated with an economic spreadsheet model developed by the company. The spreadsheet calculated project benefits/costs by year for the 2001-2025 period, including rate-of-return loadings.
- The economic analysis spreadsheet obtained four columns of annual data for each proposal directly from Prosym: generation, fuel costs, variable O&M and start-up costs, and operating margin net of variable costs. The economic analysis went further to include in its

calculations of margin each proposals fixed costs, including debt service, rate of return, taxes, and transportation.

- Each proposal's final economic analysis value was determined using the operating margin net of all fixed and variable costs on a per-MWh basis.

September 2000

Initial Screening Process

- On September 18, 2000 Avista received 32 proposals for 2,700 megawatts from 23 parties in response to its RFP. Of the 32 proposals, 8 were energy efficiency bids, 6 were for renewable resources, and 18 were supply or unit-contingent offers. Bid proposals were opened in the presence of supply and demand-side company personnel as well as a representative of the WUTC.
- Energy efficiency bids were provided to the DSM workgroup for a parallel analysis and evaluation process.
- Copies of the 24 remaining proposals were distributed to the supply-side Screening Work Group for evaluation. The supply-side Screening Work Group was made up of 12 senior-level Avista employees from varying areas of expertise, including engineering, regulatory affairs, wholesale marketing, resource optimization, finance, transmission, environmental, and natural gas.
- The supply-side Screening Work Group applied their expertise to determine the completeness of each proposal against the requirements of the RFP. Based on its completeness, it was decided by the work group whether a bid proposal should move forward to the next screen.
- Where applicable, certain parties were contacted by telephone to clarify the details of their proposals and in some instances to remove deficiencies in them.
- On September 21 the Screening Work Group gathered to share their findings and screen out those proposals that didn't significantly meet the general requirements set forth in the RFP.
- Letter notifications were sent to three parties on September 22, 2000 stating that their proposals did not significantly meet the general requirements set forth in the evaluated. A verbal review of the process to date was conducted with both WUTC and IPUC staffs.

October 2000

2nd Screening Process

- All supply-side proposals that passed through the Initial Screening Process were evaluated in a 2nd Screening Process that included the price and non-price evaluation factors described above.
- Several parties with proposals in the 2nd screening were contacted by various Screening Work Group individuals to clarify certain proposal details.
- Prosym models were run based on Henwood natural gas and electricity base case forecasts, as well as low and high market electric price scenario forecasts.

- Economic analysis/revenue requirements spreadsheets were generated using all available information.
- The supply-side Screening Work Group convened October 11, 2000 to assign values to the second round screening matrix.
- A short list of five proposals resulted from this screening process step, including market purchases, small hydro, and one utility natural gas-fired turbine option.

Screened to Short List of Seven Projects [Eval. & Decision Book #1]

- Analysis and results of this screening step were reviewed with IPUC and WUTC staff on October 18th and 20th respectively. WUTC and IPUC requested two additional natural gas-fired turbine proposals be included on the short-list, bringing the total up to seven.

November 2000

<u>RW Beck - Resource Analysis Process Review</u>

- RW Beck Consultants were retained to assess Avista's proposal evaluation process.
- RW Beck reviewed the analysis of a representative sample of bid proposals including *Prosym*™ inputs and assumptions, the WSCC Regional Electricity Market Price Forecast Study prepared by HESI, the high and low case electric price scenarios and economic models and analyses used to calculate the expected net benefit of each proposal to Avista's system.
- R. W. Beck recommended additional fine tuning of the analysis including: Resource dispatching against forecasted hourly market energy prices, separate energy and capacity prices used in the analysis, use of monthly gas prices, and modification of price sensitivity cases.

<u>RW Beck's review of Avista's analysis is summarized below:</u>

1. Avista's approach provides a reasonable way to determine which option is most viable
2. Approach taken by Avista provides for a fair comparison of the resource options and does not inherently disadvantage any of the reviewed RFP bids
3. Avista has included the necessary parameters in both the *Prosym*™ modeling and in the economic analyses
4. R. W. Beck did not find any material deficiencies (including miscalculation of formulas or omission of essential data) in the analyses reviewed

RW BeckRFP Bid Analysis Review [Eval.-Decision Book #3]

November 2000

RW Beck Energy and Capacity Price Forecast

RW Beck Market Price Forecast Assumptions and Methodology [Eval.-Decision Book #3]

- **RW Beck Forecast**

As suggested in the process review Avista contracted with RW Beck to provide a more detailed energy and capacity electric and gas forecast that included hourly electric prices and monthly gas prices. This granular forecast more closely represents market conditions on an intra-day basis when generation capacity approaches load requirements. As seen recently in the western power market, as load requirements approaches supply limits, dramatic price spikes can and will occur. While it was not the intent of this long-term analysis to estimate short-term price spikes, the purpose of the more granular analysis was to better represent the volatility in the market. RW Beck's hourly forecast captures price spikes, in a long-term sense, by assuming that the generator on the margin must receive adequate compensation to pay for all fixed and variable costs plus a profit. In a mature electric market, demand is much less than supply during most periods within a year. Occasionally, when load increases dramatically due to weather, machines trip off-line, transmission lines fail, or hydro conditions are poor, demand will approach or exceed supply. Under these circumstances generators must recover all expenses to maintain economic viability in the long-term.

- **Differences between RW Beck and HESI Forecasts**

Avista contracted with HESI to provide a long-term electric price forecast. This forecast was used during the first two screening processes of the RFP review. After retaining RW Beck to review Avista's analysis process, RW Beck suggested using a refined electric and natural gas forecast that included the following:

- Resource dispatching against forecasted hourly market energy prices
- Separate energy and capacity prices in analysis
- Use of monthly gas prices
- Modification of price sensitivity cases

The resulting differences between HESI's forecast and RW Beck's forecast were within a reasonable range of one another on an average basis. However, the granularity of RW Beck's forecast enabled the flexible resources to capture the value of the market on an hourly basis resulting in greater benefits to Avista's system.

- **Sensitivity Analysis**

  In addition to the basecase forecast, RW Beck provided three sensitivity cases in the hourly price forecast. These were:

  1. High Fuel Price Case with natural gas prices 25% higher than the Base Case
  2. Low Fuel Price Case with natural gas prices 25% lower than the Base Case
  3. High Load Case with WSCC loads 1.5% higher than the Base Case

Oct./Nov. - 2000

Third Screening Process

- Short-listed proposals were subject to greater scrutiny in the 3rd screen. Electric and natural gas transportation pricing and availability were verified. Where applicable, project heat rates and generating capacity were adjusted to account for seasonal variances and losses. The Company's Rathdrum project was refined to include two potential configurations.
- Two short-listed parties were removed from further consideration due to transmission and financial performance capability issues.
- R.W. Beck price forecasts for natural gas and electricity replaced the earlier Henwood pricing values. The biggest change was a shift to hourly electricity pricing and loads in Prosym.
- The economic analysis/revenue requirement spreadsheets were updated with all newly available information.
- Coyote Springs 2 became available as a resource option.
- On November 21, 2000 the Screening Work Group re-convened to develop a new matrix for the short-listed proposals and a recommendation for presentation to Company officers.
- Since Rathdrum continued to be a highly ranked project, community meetings were held in the Rathdrum area to discuss the potential of an expansion and accept public comments. A number of interested parties were contacted, including the Kootenai Environmental Alliance, the Pan Handle Health District, the City of Rathdrum, and various other community and neighborhood groups.

Dec. -2000

3rd Screening Results [Eval.-Decision Book #1]

Decision

- Following the conclusion of the 3rd screen, a meeting was convened with the Company officers to discuss the results of the RFP process. Results of the supply- and demand-side efforts were shared.
- On November 28-29 met with IPUC and WUTC staff in Spokane to discuss the results of the 3rd screening. Staff was informed of the expectation that Coyote Springs 2 would be the Company's choice on the supply side. R.W. Beck made a presentation on its new market price forecasts and its review of the Company's RFP process. The

consultant found the Company's process was sufficiently comprehensive and did not bias the results.

- On December 1 a final meeting with Company officers confirmed the recommendation of Coyote Springs II, and that their proposals would not be Springs 2 as the supply-side resource selection, and 3 DSM bids.

Demand Side

Spring 2000 **Updated Resource Plan / Criteria**

- The development of the demand-side portion of the RFP and the process screening, evaluating and selecting proposals benefited from the contributions of several organizations. Substantial input was received from the staffs of the IPUC and the WUTC as well as representatives of the Northwest Energy Coalition, Washington Committee on Trade and Economic Development, Northwest Energy Efficiency Coalition and Northwest Energy Services.
- Modifications to early drafts of the DSM RFP were made to accommodate an expedited timeline without placing an undue burden on potential bidders. Several criteria that were considered unnecessary for the evaluation process were deferred until after the successful proposals were selected. These criteria, including proof of insurance, permitting and licensing and similar requirements, were moved to the due diligence and contracting phase to make the bid development process less onerous.

September 2000 **Demand-Side Evaluation Matrix Development**

- The DSM RFP team acted in concert with the supply-side evaluators to develop a clear and consistent means of evaluating all proposals received under the RFP. Six criteria were identified and weights for the point scores of each characteristic were agreed upon. Both supply and demand-side proposals were to have the same weights applied to price and non-price components of the proposals.
- The criteria arrived at by the DSM RFP team consisted of price (with a weight of 50 out of 100 points), resource dispatchability (15 points), ramping, measure life and persistence (10 points), customer economics and customer service (10 points), bidder credibility (10 points) and portfolio value (5 points).
- A six-stage process for evaluating demand-side proposals was also established at this time. This process was separate from that of the evaluation of supply-side proposals, but the presence of key personnel in both the supply and demand-side teams, the use of the same timeline and the continual feedback regarding revealed avoided costs was established to ensure that an integrated supply and demand-side resource decision would be reached.

- The six-stage process established called was (1) screening of the proposals for completeness, (2) preliminary evaluation of each proposal by a seven-person team selected based upon the nature of the bid as well as establishing sufficient common personnel on each team to ensure consistency, (3) final evaluation side-by-side evaluation of all proposals by a team composed of all of the members of the preliminary evaluation teams, (4) negotiation of short-listed proposals completed by a single team, (5) the completion of due diligence on those proposals selected from the negotiation process and (6) establishing contracts with the selected proposals.
- At the bid opening it was determined at this time that, in addition to the seven demand-side proposals, one proposal submitted under the supply-side portion of the RFP would be evaluated by the DSM team. This supply-side proposal involved the acquisition to capacity from customer-owned generation more appropriately evaluated by those familiar with operations on the customer-side of the meter.
- The eight DSM proposals received were advanced to a three-person DSM screening team. Minor clarifications were required on three proposals, one proposal required the provision of a missing page and one proposal was deemed wholly deficient in substance. Fourteen questions which, if answered completely, would meet the minimum requirements upon which to base a preliminary evaluation was submitted to WSU. Five days later representatives of WSU indicated that they would not be phase.

October - November 2000

DSM Proposal Evaluation and Selection

- Seven preliminary evaluation teams were formed to study and evaluate the remaining proposals. Four of the seven members of each evaluation team were included on all evaluation teams, the other three members were selected to provide expertise specific to the individual proposal. Three of the four common members of all evaluation teams were also included on the supply-side evaluation team.
- During the preliminary evaluation each proposer was contacted by conference call at least once, and usually several times, to clarify the content of the proposal. Preliminary scoring of all proposals were completed at the end of this phase.
- All members of the preliminary evaluation teams staffed the final evaluation process. Initial meetings were convened to discuss capacity and energy proposals, followed by a final meeting of both categories of proposal.
- The final evaluation expanded on the characteristics of the proposals identified in the preliminary evaluation process. Based upon a discussion and ranking of each project for each of the six criteria a final overall scoring and ranking of proposals emerged.
- The last duty of the evaluation team was to determine which of the seven ranked proposals had the potential to be developed into

successful ventures. In this final analysis the lowest ranking two proposals were deemed to be fatally flawed in one or more categories, and were consequently eliminated from consideration.

- The five short-listed proposals were forwarded to a negotiation team. The composition of the negotiation team was such that all individuals were familiar with the proposal characteristics by virtue of their involvement in the evaluation process. Two of the members of the negotiation team were also involved in the supply-side evaluation and negotiation of proposals.
- Each bidder was contacted, usually on several occasions, by the negotiation team as a whole. Bidders were again given the opportunity to explain the characteristics of their proposal, respond to questions and to make voluntary modifications to their proposal. Upon the conclusion of the negotiations each modified proposal received a final evaluation and scoring by the negotiation team. Three of the five proposals under negotiation were selected as successful proposals responding to these questions. The proposal was consequently eliminated in the screening.

December-February 2000 / 2001

Proposal Contracting and Implementation

- Those proposals that had been selected were advanced to due diligence. The due diligence team was originally composed of three and later (due to changes in job responsibilities) four individuals. During due diligence the bidder in being required to complete those portions of the RFP that were deferred in order to facilitate a streamlined bidding process (proof of insurance, permitting, licenses etc.). References, financial and other characteristics deemed critical to the proposal success will also be verified.
- Presuming that selected proposals are satisfactorily completed and critical characteristics verified in due diligence, the contracting phase will complete the RFP. During this phase the bidder and company will commit to contractual form the understandings made during the negotiation process.
- Implementation of the contracted proposals is expected to begin immediately upon the completion of the contract.

Overall RFP Evaluation & Reporting

February 2001

RFP Evaluation

- The Company's documentation of its resource selection process has been compiled for future filing with the Washington and Idaho Commissions. The purpose of the evaluation is to chronicle the circumstances, events and the steps taken in conjunction with the Company's resource decision in 2000.

July 12, 2000

AVISTA CORPORATION

1997 Integrated Resource Plan Update

I. Introduction:

Avista's last Integrated Resource Plan (IRP) was filed with the Commission on August 25, 1997. That plan showed that the company was surplus for many years into the future. Since then many things have changed in the electric utility industry and for Avista. Therefore, the company has prepared this updated IRP to include those significant changes. As discussed later, this updated IRP will also serve as the basis for a Request- for-Proposal (RFP) that Avista plans to issue.

The following information has been presented at various TAC meetings and will become a integral part of the next IRP.

II. 1997 IRP Update

1. Load Forecast

The 2000 electric sales forecast was prepared during the summer of 1999. The forecast of firm sales to the core-market is one of the most critical elements and was presented and discussed at the TAC meeting. 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 electrical energy forecast shows an annual average load of 1013 aMW in 2001 increasing to 1159 aMW in 2009. The peak forecast shows 1594 MW in 2001 with 1851 MW in the year 2009. The ten-year compound growth rate for residential usage is 2.3 percent, commercial is 3.9 percent and industrial is 1.6 percent. The overall total energy forecast has a compound growth rate of 1.9 percent.

The annual load forecast numbers, for both peak and energy, through the year 2009 can be found on the Requirements and Resources tabulation sheet.

2. Resource Assessment

<u>Centralia</u>:
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 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.

Hydro Relicensing:
Avista Corp. was granted by the FERC on Feb. 23, 2000, a new 45-year license to operate the Noxon Rapids and Cabinet Gorge hydroelectric projects on the lower Clark Fork River. The licensing effort 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., Feb. 18, 1999, and contained a comprehensive settlement agreement with 27 signatories.

This 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 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 will spend approximately $4.7 million annually with a significant expenditure earmarked for enhancing bull trout populations.

Contract Sales and Purchases:
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. Those are the PacifiCorp, PGE and Snohomish PUD contracts.

*PacifiCorp and the company entered into a ten year summer capacity sale for the period June 16, 1994 through September 15, 2003 (with PacifiCorp option to extend for up to five years). The company delivers 150 MW of summer capacity with energy purchased at 25 percent load factor based on variable prices.

*Portland General Electric is purchasing from the company 150 MW of capacity through December 31, 2016. The energy associated with the capacity deliveries has to be returned within 168 hours.

*Snohomish PUD purchases 100 MW of firm capacity with a minimum amount of firm energy at 50 percent load factor from the company. The contract ends September 2006.

Avista also has a large cogeneration facility (Potlatch Forest Industry) in its service territory that entered into a ten-year contract with the company which terminates at the end of 2001. The power received from Potlatch has a maximum capacity of 59 MW and average energy of 55 aMW.

Hydro Upgrades:
In 1999, the company completed the program to replace all four runners at Long Lake, which increased the capability 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.

3. Reserves Analysis

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.

The company's planning reserves are based on 10 percent increase in peak loads or one day in twenty years and 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 we would expect the peak to be 1713 MW on the extreme day (-10 degrees F).

Avista's operating reserves are considered a part of the company's planning reserve numbers. The operating reserves are 5 percent of hydro generation and 7 percent of thermal and are what we are legally required to carry under regional criteria.

4. 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.

PROSYM is a commercially available production cost model used to perform electric planning and operational studies. Due to its hourly chronological design and its capability to accurately dispatch the company's flexible hydro system, we use PROSYM to perform dispatch analyses of various generation sources. A key point to remember is that PROSYM is a production cost model. The resource inputs include machine characteristics, fuel costs, and variable operation and maintenance costs. The model does not calculate the total cost of the resource. After the dispatch information is obtained from PROSYM, traditional economic analyses of each resource option must be performed.

An example of a PROSYM run with a new combined cycle combustion turbine modeled into the company's system is shown in Appendix A.

5. Long Term Natural Gas and Electric Price Forecasts

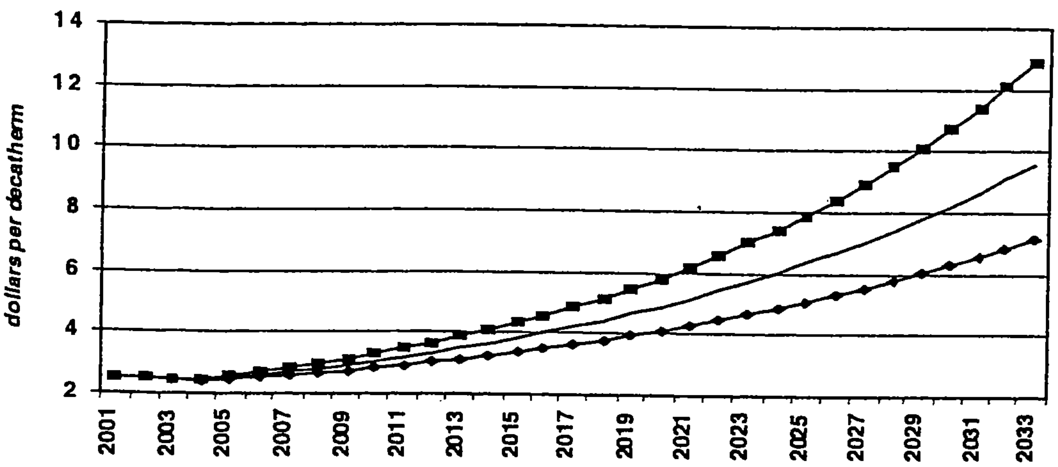
There is much uncertainty in the natural gas and electric price forecasts. Price volatility has increased recently given extremely high prices in the daily and forward markets. The company knows that there will be periods of high prices and periods of low prices as the price curves fluctuate based on demand and supply criteria. It is the company's goal to provide and use a forecast that is reasonable in its start point and escalation for the long term. 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.

Key to any "buy or build" decision is an understanding of the future prices for electricity and natural gas. 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. As discussed above, there is uncertainty in both the near-term and long-term natural gas price forecasts. Avista therefore relies on a set of forward predictions it believes account for a range of possible future outcomes.

The Natural Gas Price Forecast

The price forecasts developed for this update build on the natural gas forecast contained in Avista's forthcoming 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 median or base case forecast shown below.

Northwest Natural Gas Price Forecasts
2001-2033 nominal dollars



As detailed in the graph in the base case, 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.

The Electricity Price Forecast

With the scenarios for future natural gas prices established, electricity price forecasts was estimated using a "spark 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 June 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 June 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 ten thousand Btu/kWh with base case gas prices, 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.

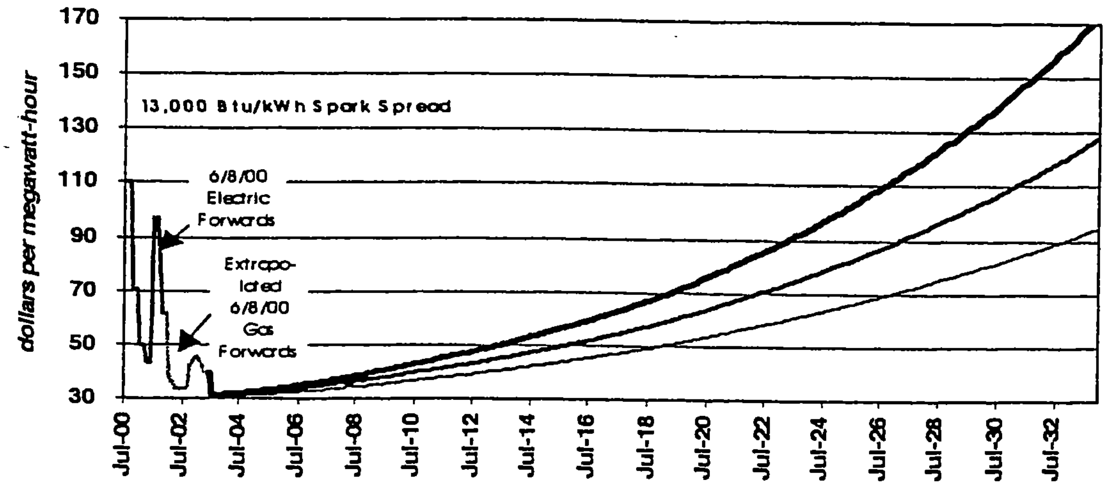
Where the spark spread is assumed to be fifteen thousand Btu/kWh, our high case estimate, electricity prices equal $39 per MWh in 2004. Prices rise to $61 in 2013 and then to $153 in 2033. The average annual price escalation again is 4.8 percent nominal. In real terms, prices rise from $36 in 2004 to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

Northwest Electricity Price Forecasts
July 2000-2033 nominal dollars



6. 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.

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.

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.

Attached are the nominal levelized costs in 1999 dollars of many supply-side resource types made available by the Power Council (see Appendix B).

Nuclear plant costs are not on the list, although we know (from previous Power Council studies) that nuclear total cost is above 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 plants. 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. We have included in the proposed RFP a provision to bid to Avista 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 C for further information.

7. Screening Results

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. As shown in Appendix B, the Northwest Power Planning Council costs for natural gas fired generation projects range from approximately 41 mills to 43 mills.

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 will solicit resource bids from the market in an upcoming Request-for-Proposals (RFP). The company is hoping for innovative bids from project developers. The RFP bids will be evaluated against the information that has been gathered both internally and externally.

8. Load and Resource Summary

General:
Included is Avista's annual Requirements and Resources (Load and Resource Summary) that shows the company's load and resource position on an annual basis for the next ten years (see Appendix D). It is dated June 1, 2000 and will be the same one used in the 2000 IRP. The peak column is the January peak (the highest forecasted peak for the year) and the average column is the annual 12-month average for the year. The resource peak numbers are what could be expected as maximum capacity outputs during January. The hydro peak and energy numbers are from the final regulation done by the Northwest Power Pool and reflect the reservoir levels in January per the hydro regulation study (one-year critical period, 1936-37 water). The average energy numbers are the expected 12-month averages for the loads, resources and contracts.

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 Section 3).

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 (with 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. Lines 24 and 25 are the company's existing simple-cycle combustion turbines, and lines 33 and 34 are the expected thermal generation output from Kettle Falls and Colstrip.

Line 29 shows the BPA residential exchange contract and 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, Avista feels it is firm enough to be included.

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.

Resource Flexibility:
Flexible generation resources are a key component to meet the requirements of Avista's customers. As depicted in the charts on pages 8 and 9 in Appendix E, 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. Even with these resources, Avista still must purchase peak energy products to meet customer demand during different times. The market today tends to offer standard heavy load hour and light load hour products that do not meet load shaping or following needs.

2004 Study:
A detailed tabulation of the load and resource requirements study of the year 2004 is also attached,(see Appendix E). We chose the year 2004 for an in-depth study because, as mentioned above, 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. We 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.

Load growth expectations based on the forecasted methodologies are explained under Section 1. 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 deciding to serve 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 requirements.

APPENDIX A

PROSYM OUTPUT
EXISTING SYSTEM

Station Report

No.	Station	Energy GWh	Cap Fctr %	Sta-rts	Fuel Burn GBtu	Heat Rate Btu/kWh	Hours per Unit	FuelOrPrch ¢/MBtu <F> $/MWh <P>	Cost $000 $000	Start Fuel GBtu	Start Cost $000	O&M Fixed $000	O&M Varbl $000	Opertg Cost $/MWh	Total Cost $/MWh	Total Cost $000
1	HLH PURCHASE	685.8	9.1	107			7669	37.4	25627		0	0	0	37.37	37.37	25627
2	LLH PURCHASE	694.7	12.3	54			8130	26.9	18689		0	0	0	26.90	26.90	18689
3	HLH Sale	-163.4	2.2	255			4940	30.1	-4919		0	0	0	30.11	30.11	-4919
4	LLH Sale	-123.4	2.2	265			5678	15.3	-1892		0	0	0	15.32	15.32	-1892
5	Spokane River	1055.1	71.6	0			8784	0.0	0		0	0	0	0.00	0.00	0
6	Clark Fork Hy	2848.3	42.0	0			8784	0.0	0		0	0	0	0.00	0.00	0
7	Mid Columbia	994.4	62.9	0			8784	0.0	0		0	0	0	0.00	0.00	0
8	Colstrip 3	913.3	93.7	10			8228	6.4	5819		0	0	2491	9.10	9.10	8310
9	Colstrip 4	913.1	93.6	8			8226	6.4	5818		0	0	2491	9.10	9.10	8308
10	NortheastTurbine	56.3	10.2	55	704.4	12500	1012	296.1	2086	0	0	0	282	42.01	42.01	2367
11	Rathdrum 1	220.4	31.4	133	2490.3	11300	2856	299.5	7458	0	0	0	225	34.86	34.86	7683
12	Rathdrum 2	220.4	31.4	133	2490.3	11300	2856	299.5	7458	0	0	0	225	34.86	34.86	7683
13	Kettle Falls	383.9	93.0	5			8169	9.5	3647		15	0	902	11.85	11.89	4565
14	Potlatch Cogen	0.0	0.0	0			8784	0.0	0		0	0	0	0.00	0.00	0
15	Upriver Firm	49.5	100.0	0			4368	0.0	0		0	0	0	0.00	0.00	0
16	BPAexchange	108.4	100.0	0			8784	0.0	0		0	0	0	0.00	0.00	0
17	PPLExRtn	29.3	100.0	1			2184	0.0	0		0	0	0	0.00	0.00	0
18	PPLExDel	-29.3	100.0	1			2184	0.0	0		0	0	0	0.00	0.00	0
19	Entitlement	3.6	40.7	78			961	0.0	0		0	0	0	0.00	0.00	0
20	CSPE	0.0	0.0	0			0	0.0	0		0	0	0	0.00	0.00	0
21	BPA Subscr	412.8	100.0	0			8784	0.0	0		0	0	0	0.00	0.00	0
22	BPACan Ent	0.0	0.0	0			0	0.0	0		0	0	0	0.00	0.00	0
23	WNP3	374.3	100.0	0			8784	0.0	0		0	0	0	0.00	0.00	0
24	Black Crk	8.2	100.0	0			8784	0.0	0		0	0	0	0.00	0.00	0
25	BPA5yr Purchase	0.0	0.0	0			0	0.0	0		0	0	0	0.00	0.00	0
26	Sempra Purchase	0.0	0.0	0			0	0.0	0		0	0	0	0.00	0.00	0
27	Cin Purchase	0.0	0.0	0			0	0.0	0		0	0	0	0.00	0.00	0
28	Esi purchase	0.0	0.0	0			0	0.0	0		0	0	0	0.00	0.00	0
29	Enr3yr purchase	0.0	0.0	0			0	0.0	0		0	0	0	0.00	0.00	0
30	Enr2yr Purchase	0.0	0.0	0			0	0.0	0		0	0	0	0.00	0.00	0
31	Puget Sale	0.0	0.0	0			8784	0.0	0		0	0	0	0.00	0.00	0
32	PGE Capacity	-1.5	100.0	0			8784	0.0	0		0	0	0	0.00	0.00	0
33	Douglas Capacity	0.0	0.0	0			0	0.0	0		0	0	0	0.00	0.00	0
34	EWEB Sale	0.0	0.0	0			0	0.0	0		0	0	0	0.00	0.00	0
35	SPUD Capacity	-629.3	100.0	0			8784	0.0	0		0	0	0	0.00	0.00	0
36	Clark Sale	0.0	0.0	0			0	0.0	0		0	0	0	0.00	0.00	0
37	PPL94 Sale	0.0	0.0	0			0	0.0	0		0	0	0	0.00	0.00	0
38	CEPM57 Sale	0.0	0.0	0			0	0.0	0		0	0	0	0.00	0.00	0
	YSTEM PRODUCTION	9025.0		1105	5685.0	11436			69790	0	15	0	6616	8.47	8.47	76421

ontinues...

Station Group Report

No. Group	Energy GWh	Cap Fctr %	Sta-rts	Fuel Burn GBtu	Heat Rate Btu/kWh	Hours per Unit	FuelOrPrch ¢/MBtu <F> $/MWh <P>	Cost $000 $000	Start Fuel GBtu	Start Cost $000	O&M Fixed $000	O&M Varbl $000	Opertg Cost $/MWh	Total Cost $/MWh	Total Cost $000
Native Load	9021.4														
Dump Power	0.0													0.00	0
Tran. Losses	0.0														
PS Load	3.6														
LESS Resources (Exports):															
1 HLH Purch	685.8	9.1	107				37.4	25627		0	0	0	37.37	37.37	25627
2 LLH Purch	694.7	12.3	54				26.9	18689		0	0	0	26.90	26.90	18689
3 HLH Sale	-163.4	2.2	255				0.0	-4919		0	0	0	30.11	30.11	-4919
4 LLH Sale	-123.4	2.2	265				0.0	-1892		0	0	0	15.32	15.32	-1892
5 Spokane R	1055.1	71.6	0				0.0	0		0	0	0	0.00	0.00	0
6 Clark Fork	2848.3	42.0	0				0.0	0		0	0	0	0.00	0.00	0
7 Mid Col	994.4	62.9	0				0.0	0		0	0	0	0.00	0.00	0
8 Colstrip	1826.4	93.7	17				6.4	11637		0	0	4982	9.10	9.10	16619
9 Northeast	56.3	10.2	55	704.4	12500		296.1	2086	0	0	0	282	42.01	42.01	2367
10 Rathdrum	440.8	31.4	266	4980.7	11300		299.5	14916	0	0	0	450	34.86	34.86	15365
11 Kettle Fls	383.9	93.0	5				9.5	3647		15	0	902	11.85	11.89	4565
12 Cogen	49.5	100.0	0				0.0	0		0	0	0	0.00	0.00	0
13 Exchange	108.4	100.0	2				0.0	0		0	0	0	0.00	0.00	0
14 Contract Purchas	798.9	99.4	78				0.0	0		0	0	0	0.00	0.00	0
15 Contract Sale	-630.8	100.0	0				0.0	0		0	0	0	0.00	0.00	0
[Non-PS Resources	9021.4]														
[PS Generation	3.6]														
Resource Totals	9025.0		1105	5685.0	11436			69790	0	15	0	6616	8.47	8.47	76421
E.N.S.	0.0													100.00	0
SYSTEM														8.47	76421

Spinning reserve deficit report

Type	No.	Deficit area	Hrs	-Spinning reserve- Energy MW	Cost $000	Hrs	-Primary reserve- Energy MW	Cost $000
Syst	0	System	627	23788	0	319	9380	0

Emission Report

No. Station	NOx (1000tn)	Emiss 7 (1000tn)	Emiss 8 (1000tn)

1	HLH PURCHASE	0.000	0.000	0.000

Continues...

Continues...

No.	Station	NOx (1000tn)	Emiss 7 (1000tn)	Emiss 8 (1000tn)
2	LLH PURCHASE	0.000	0.000	0.000
3	HLH Sale	0.000	0.000	0.000
4	LLH Sale	0.000	0.000	0.000
5	Spokane River	0.000	0.000	0.000
6	Clark Fork Hy	0.000	0.000	0.000
7	Mid Columbia	0.000	0.000	0.000
8	Colstrip 3	0.000	0.000	0.000
9	Colstrip 4	0.000	0.000	0.000
10	NortheastTurbine	0.148	0.000	0.000
11	Rathdrum 1	0.074	0.010	0.076
12	Rathdrum 2	0.074	0.010	0.076
13	Kettle Falls	0.000	0.000	0.000
14	Potlatch Cogen	0.000	0.000	0.000
15	Upriver Firm	0.000	0.000	0.000
16	BPAexchange	0.000	0.000	0.000
17	PPLExRtn	0.000	0.000	0.000
18	PPLExDel	0.000	0.000	0.000
19	Entitlement	0.000	0.000	0.000
20	CSPE	0.000	0.000	0.000
21	BPA Subscr	0.000	0.000	0.000
22	BPACan Ent	0.000	0.000	0.000
23	WNP3	0.000	0.000	0.000
24	Black Crk	0.000	0.000	0.000
25	BPA5yr Purchase	0.000	0.000	0.000
26	Sempra Purchase	0.000	0.000	0.000
27	Cin Purchase	0.000	0.000	0.000
28	Esi purchase	0.000	0.000	0.000
29	Enr3yr purchase	0.000	0.000	0.000
30	Enr2yr Purchase	0.000	0.000	0.000
31	Puget Sale	0.000	0.000	0.000
32	PGE Capacity	0.000	0.000	0.000
33	Douglas Capacity	0.000	0.000	0.000
34	EWEB Sale	0.000	0.000	0.000
35	SPUD Capacity	0.000	0.000	0.000
36	Clark Sale	0.000	0.000	0.000
37	PPL94 Sale	0.000	0.000	0.000
38	CEPM57 Sale	0.000	0.000	0.000
SYSTEM EMISSIONS		0.30	0.02	0.15

No.	Station	NOx (1000tn)	Emiss 7 (1000tn)	Emiss 8 (1000tn)
1	HLH PURCHASE	0.000	0.000	0.000
2	LLH PURCHASE	0.000	0.000	0.000
3	HLH Sale	0.000	0.000	0.000
4	LLH Sale	0.000	0.000	0.000
5	Spokane River	0.000	0.000	0.000
6	Clark Fork Hy	0.000	0.000	0.000
7	Mid Columbia	0.000	0.000	0.000
8	Colstrip 3	0.000	0.000	0.000
9	Colstrip 4	0.000	0.000	0.000

No.	Station	NOx (1000tn)	Emiss 7 (1000tn)	Emiss 8 (1000tn)
10	NortheastTurbine	0.148	0.000	0.000
	SumasRock Gas	0.148	0.000	0.000
11	Rathdrum 1	0.074	0.010	0.076
	Rathdrum Gas	0.074	0.010	0.076
12	Rathdrum 2	0.074	0.010	0.076
	Rathdrum Gas	0.074	0.010	0.076
13	Kettle Falls	0.000	0.000	0.000
14	Potlatch Cogen	0.000	0.000	0.000
15	Upriver Firm	0.000	0.000	0.000
16	BPAexchange	0.000	0.000	0.000
17	PPLExRtn	0.000	0.000	0.000
18	PPLExDel	0.000	0.000	0.000
19	Entitlement	0.000	0.000	0.000
20	CSPE	0.000	0.000	0.000
21	BPA Subscr	0.000	0.000	0.000
22	BPACan Ent	0.000	0.000	0.000
23	WNP3	0.000	0.000	0.000
24	Black Crk	0.000	0.000	0.000
25	BPA5yr Purchase	0.000	0.000	0.000
26	Sempra Purchase	0.000	0.000	0.000
27	Cin Purchase	0.000	0.000	0.000
28	Esi purchase	0.000	0.000	0.000
29	Enr3yr purchase	0.000	0.000	0.000
30	Enr2yr Purchase	0.000	0.000	0.000
31	Puget Sale	0.000	0.000	0.000
32	PGE Capacity	0.000	0.000	0.000
33	Douglas Capacity	0.000	0.000	0.000
34	EWEB Sale	0.000	0.000	0.000
35	SPUD Capacity	0.000	0.000	0.000
36	Clark Sale	0.000	0.000	0.000
37	PPL94 Sale	0.000	0.000	0.000
38	CEPM57 Sale	0.000	0.000	0.000
SYSTEM EMISSIONS		0.30	0.02	0.15

No.	Group	NOx (1000tn)	Emiss 7 (1000tn)	Emiss 8 (1000tn)
1	HLH Purch	0.000	0.000	0.000
2	LLH Purch	0.000	0.000	0.000
3	HLH Sale	0.000	0.000	0.000
4	LLH Sale	0.000	0.000	0.000
5	Spokane R	0.000	0.000	0.000
6	Clark Fork	0.000	0.000	0.000
7	Mid Col	0.000	0.000	0.000
8	Colstrip	0.000	0.000	0.000
9	Northeast	0.148	0.000	0.000
10	Rathdrum	0.149	0.020	0.151
11	Kettle Fls	0.000	0.000	0.000
12	Cogen	0.000	0.000	0.000
13	Exchange	0.000	0.000	0.000
14	Contract Purchas	0.000	0.000	0.000
15	Contract Sale	0.000	0.000	0.000
SYSTEM EMISSIONS		0.30	0.02	0.15

Time of Day Marginal Cost Summary

Period	Total hours	% of hours	Average Marg Cost
1 On Peak	5024	57.2	37.22
2 Off Peak	3760	42.8	25.32
Total	8784	100.0	32.12

Percent Time at Margin, by Station Group

Groups	Time of Day Periods 1	2	All
1 HLH Purch	76.5	0.0	43.8
2 LLH Purch	0.0	82.6	35.4
3 HLH Sale	23.5	0.0	13.4
4 LLH Sale	0.0	17.4	7.4
5 Spokane R	0.0	0.0	0.0
6 Clark Fork	0.0	0.0	0.0
7 Mid Col	0.0	0.0	0.0
8 Colstrip	0.0	0.0	0.0
9 Northeast	0.0	0.0	0.0
10 Rathdrum	0.0	0.0	0.0
11 Kettle Fls	0.0	0.0	0.0
12 Cogen	0.0	0.0	0.0
13 Exchange	0.0	0.0	0.0

14 Contract Purchas	0.0	0.0	0.0

Continues...

Groups	Time of Day Periods 1	2	All
15 Contract Sale	0.0	0.0	0.0
Dump Power	0.0	0.0	0.0
E.N.S.	0.0	0.0	0.0

Cost at Margin, by Period and Station Group (mills)

Groups	Time of Day Periods 1	2	All
1 HLH Purch	38.6	0.0	38.6
2 LLH Purch	0.0	27.3	27.3
3 HLH Sale	32.7	0.0	32.7
4 LLH Sale	0.0	15.8	15.8
5 Spokane R	0.0	0.0	0.0
6 Clark Fork	0.0	0.0	0.0
7 Mid Col	0.0	0.0	0.0
8 Colstrip	0.0	0.0	0.0
9 Northeast	0.0	0.0	0.0
10 Rathdrum	0.0	0.0	0.0
11 Kettle Fls	0.0	0.0	0.0
12 Cogen	0.0	0.0	0.0
13 Exchange	0.0	0.0	0.0
14 Contract Purchas	0.0	0.0	0.0
15 Contract Sale	0.0	0.0	0.0
Dump Power	0.0	0.0	0.0
E.N.S.	0.0	0.0	0.0

Average Hourly Cost Summary

Period	Total hours	% of hours	Total GWh	Average cost
1 On Peak	5024	57.2	5613	8.74
2 Off Peak	3760	42.8	3409	8.03
Total	8784	100.0	9021	8.47

Fuel Use Report

No. Fuel	GBtu used	Commod $000	Volume1 $000	Volume2 $000	Demand $000	Total $000	¢/MBtu average
1 Kingsgate Gas	0.0	0	0	0	0	0.00	0.0

2	Rathdrum Gas	4980.7	13571	1345	0	0	14915.70	299.5
3	SumasRock Gas	704.4	1855	229	1	0	2085.58	296.1

Continues...

Station Fuel Report (GBtu used)

No.	Station	SumasRock Gas	Rathdrum Gas
10	NortheastTurbine	704.4	-
11	Rathdrum 1	-	2490.3
12	Rathdrum 2	-	2490.3

Plant Fuel Report (GBtu used)

No.	Plant	SumasRock Gas	Rathdrum Gas

No.	Station	Max Cap MW	Hours	Fuel	Energy GWh	Fuel GBtu	Fuel Units	Cost $000	Price ¢/MBtu
10	NortheastTurbine	69.0	1012	SumasRock Gas	56.3	704.4		2085.6	296.10
11	Rathdrum 1	88.0	2856	Rathdrum Gas	220.4	2490.3		7457.9	299.47
12	Rathdrum 2	88.0	2856	Rathdrum Gas	220.4	2490.3		7457.9	299.47

Build ID: 002086

PROSYM V3.3b1N Copyright 1988-1999 by Henwood Energy Services, Inc. P-035-1

Avista Corp

2004: 12 Months thru Dec. Avista Load and Resource Study -- March 2000 -- S. Silkworth

1 iter Convergent Monte

06-20-2000
2:33:39 PM

DRAFT

PROSYM OUTPUT
ADD CCCT AT RATHDRUM
EXAMPLE

Station Report

No.	Station	Energy GWh	Cap Fctr %	Sta-rts	Fuel Burn GBtu	Heat Rate Btu/kWh	Hours per Unit	FuelOrPrch ¢/MBtu <F> $/MWh <P>	Cost $000 $000	Start Fuel GBtu	Start Cost $000	O&M Fixed $000	O&M Varbl $000	Opertg Cost $/MWh	Total Cost $/MWh	Total Cost $000
1	HLH PURCHASE	109.4	1.5	264			4867	35.5	3879		0	0	0	35.47	35.47	3879
2	LLH PURCHASE	241.4	4.3	221			6562	25.8	6220		0	0	0	25.77	25.77	6220
3	HLH Sale	-695.3	9.2	109			7680	35.0	-24328		0	0	0	34.99	34.99	-24328
4	LLH Sale	-285.0	5.1	208			7246	22.4	-6384		0	0	0	22.41	22.41	-6384
5	Spokane River	1055.1	71.6	0			8784	0.0	0		0	0	0	0.00	0.00	0
6	Clark Fork Hy	2848.3	42.0	0			8784	0.0	0		0	0	0	0.00	0.00	0
7	Mid Columbia	994.4	62.9	0			8784	0.0	0		0	0	0	0.00	0.00	0
8	Colstrip 3	913.3	93.7	10			8228	6.4	5819		0	0	2491	9.10	9.10	8310
9	Colstrip 4	913.1	93.6	8			8226	6.4	5818		0	0	2491	9.10	9.10	8308
10	NortheastTurbine	56.3	10.2	55	704.4	12500	1012	296.1	2086	0	0	0	282	42.01	42.01	2367
11	Rathdrum 1	220.4	31.4	133	2490.3	11300	2856	299.5	7458	0	0	0	225	34.86	34.86	7683
12	Rathdrum 2	220.4	31.4	133	2490.3	11300	2856	299.5	7458	0	0	0	225	34.86	34.86	7683
13	RCCCT	1724.0	85.2	68	13294.9	7712	7481	275.4	36611	0	0	0	1759	22.26	22.26	38370
14	Kettle Falls	383.1	92.8	9			8152	9.5	3640		26	0	900	11.85	11.92	4567
15	Potlatch Cogen	0.0	0.0	0			8784	0.0	0		0	0	0	0.00	0.00	0
16	Upriver Firm	49.5	100.0	0			4368	0.0	0		0	0	0	0.00	0.00	0
17	BPAexchange	108.4	100.0	0			8784	0.0	0		0	0	0	0.00	0.00	0
18	PPLExRtn	29.3	100.0	1			2184	0.0	0		0	0	0	0.00	0.00	0
19	PPLExDel	-29.3	100.0	1			2184	0.0	0		0	0	0	0.00	0.00	0
20	Entitlement	3.6	41.7	84			989	0.0	0		0	0	0	0.00	0.00	0
21	CSPE	0.0	0.0	0			0	0.0	0		0	0	0	0.00	0.00	0
22	BPA Subscr	412.8	100.0	0			8784	0.0	0		0	0	0	0.00	0.00	0
23	BPACan Ent	0.0	0.0	0			0	0.0	0		0	0	0	0.00	0.00	0
24	WNP3	374.3	100.0	0			8784	0.0	0		0	0	0	0.00	0.00	0
25	Black Crk	8.2	100.0	0			8784	0.0	0		0	0	0	0.00	0.00	0
26	BPA5yr Purchase	0.0	0.0	0			0	0.0	0		0	0	0	0.00	0.00	0
27	Sempra Purchase	0.0	0.0	0			0	0.0	0		0	0	0	0.00	0.00	0
28	Cin Purchase	0.0	0.0	0			0	0.0	0		0	0	0	0.00	0.00	0
29	Esi purchase	0.0	0.0	0			0	0.0	0		0	0	0	0.00	0.00	0
30	Enr3yr purchase	0.0	0.0	0			0	0.0	0		0	0	0	0.00	0.00	0
31	Enr2yr Purchase	0.0	0.0	0			0	0.0	0		0	0	0	0.00	0.00	0
32	Puget Sale	0.0	0.0	0			8784	0.0	0		0	0	0	0.00	0.00	0
33	PGE Capacity	-1.5	100.0	0			8784	0.0	0		0	0	0	0.00	0.00	0
34	Douglas Capacity	0.0	0.0	0			0	0.0	0		0	0	0	0.00	0.00	0
35	EWEB Sale	0.0	0.0	0			0	0.0	0		0	0	0	0.00	0.00	0
36	SPUD Capacity	-629.3	100.0	0			8784	0.0	0		0	0	0	0.00	0.00	0
37	Clark Sale	0.0	0.0	0			0	0.0	0		0	0	0	0.00	0.00	0
38	PPL94 Sale	0.0	0.0	0			0	0.0	0		0	0	0	0.00	0.00	0
39	CEPM57 Sale	0.0	0.0	0			0	0.0	0		0	0	0	0.00	0.00	0
	STEM PRODUCTION	9025.1		1304	18979.9	8545			48276	0	26	0	8372	6.28	6.28	56675

ntinues...

Station Group Report

No. Group	Energy GWh	Cap Fctr %	Sta-rts	Fuel Burn GBtu	Heat Rate Btu/kWh	Hours per Unit	FuelOrPrch ¢/MBtu <F> $/MWh <P>	Cost $000 $000	Start Fuel GBtu	Start Cost $000	O&M Fixed $000	O&M Varbl $000	Opertg Cost $/MWh	Total Cost $/MWh	Total Cost $000
Native Load	9021.4														
Dump Power	0.0														
Tran. Losses	0.0													0.00	0
PS Load	3.6														
LESS Resources (Exports):															
1 HLH Purch	109.4	1.5	264				35.5	3879		0	0	0	35.47	35.47	3879
2 LLH Purch	241.4	4.3	221				25.8	6220		0	0	0	25.77	25.77	6220
3 HLH Sale	-695.3	9.2	109				0.0	-24328		0	0	0	34.99	34.99	-24328
4 LLH Sale	-285.0	5.1	208				0.0	-6384		0	0	0	22.41	22.41	-6384
5 Spokane R	1055.1	71.6	0				0.0	0		0	0	0	0.00	0.00	0
6 Clark Fork	2848.3	42.0	0				0.0	0		0	0	0	0.00	0.00	0
7 Mid Col	994.4	62.9	0				0.0	0		0	0	0	0.00	0.00	0
8 Colstrip	1826.4	93.7	17				6.4	11637		0	0	4982	9.10	9.10	16619
9 Northeast	56.3	10.2	55	704.4	12500		296.1	2086	0	0	0	282	42.01	42.01	2367
10 Rathdrum	440.8	31.4	266	4980.7	11300		299.5	14916	0	0	0	450	34.86	34.86	15365
11 RathdrumCCCT	1724.0	85.2	68	13294.9	7712		275.4	36611	0	0	0	1759	22.26	22.26	38370
12 Kettle Fls	383.1	92.8	9				9.5	3640		26	0	900	11.85	11.92	4567
13 Cogen	49.5	100.0	0				0.0	0		0	0	0	0.00	0.00	0
14 Exchange	108.4	100.0	2				0.0	0		0	0	0	0.00	0.00	0
15 Contract Purchas	799.0	99.4	84				0.0	0		0	0	0	0.00	0.00	0
16 Contract Sale	-630.8	100.0	0				0.0	0		0	0	0	0.00	0.00	0
[Non-PS Resources	9021.4]														
[PS Generation	3.6]														
Resource Totals	9025.1		1304	18979.9	8545			48276	0	26	0	8372	6.28	6.28	56675
E.N.S.	0.0													100.00	0
SYSTEM														6.28	56675

Spinning reserve deficit report

Type	No.	Deficit area	Hrs	-Spinning reserve- Energy MW	Cost $000	Hrs	-Primary reserve- Energy MW	Cost $000
Syst	0	System	744	31057	0	436	12879	0

Continues...

Emission Report

No.	Station	NOx (1000tn)	Emiss 7 (1000tn)	Emiss 8 (1000tn)
1	HLH PURCHASE	0.000	0.000	0.000
2	LLH PURCHASE	0.000	0.000	0.000
3	HLH Sale	0.000	0.000	0.000
4	LLH Sale	0.000	0.000	0.000
5	Spokane River	0.000	0.000	0.000
6	Clark Fork Hy	0.000	0.000	0.000
7	Mid Columbia	0.000	0.000	0.000
8	Colstrip 3	0.000	0.000	0.000
9	Colstrip 4	0.000	0.000	0.000
10	NortheastTurbine	0.148	0.000	0.000
11	Rathdrum 1	0.074	0.010	0.076
12	Rathdrum 2	0.074	0.010	0.076
13	RCCCT	0.195	0.026	0.198
14	Kettle Falls	0.000	0.000	0.000
15	Potlatch Cogen	0.000	0.000	0.000
16	Upriver Firm	0.000	0.000	0.000
17	BPAexchange	0.000	0.000	0.000
18	PPLExRtn	0.000	0.000	0.000
19	PPLExDel	0.000	0.000	0.000
20	Entitlement	0.000	0.000	0.000
21	CSPE	0.000	0.000	0.000
22	BPA Subscr	0.000	0.000	0.000
23	BPACan Ent	0.000	0.000	0.000
24	WNP3	0.000	0.000	0.000
25	Black Crk	0.000	0.000	0.000
26	BPA5yr Purchase	0.000	0.000	0.000
27	Sempra Purchase	0.000	0.000	0.000
28	Cin Purchase	0.000	0.000	0.000
29	Esi purchase	0.000	0.000	0.000
30	Enr3yr purchase	0.000	0.000	0.000
31	Enr2yr Purchase	0.000	0.000	0.000
32	Puget Sale	0.000	0.000	0.000
33	PGE Capacity	0.000	0.000	0.000
34	Douglas Capacity	0.000	0.000	0.000
35	EWEB Sale	0.000	0.000	0.000
36	SPUD Capacity	0.000	0.000	0.000
37	Clark Sale	0.000	0.000	0.000
38	PPL94 Sale	0.000	0.000	0.000
39	CEPM57 Sale	0.000	0.000	0.000
SYSTEM EMISSIONS		0.49	0.05	0.35

No.	Station	NOx (1000tn)	Emiss 7 (1000tn)	Emiss 8 (1000tn)
1	HLH PURCHASE	0.000	0.000	0.000
2	LLH PURCHASE	0.000	0.000	0.000

Continues...

No.	Station	NOx (1000tn)	Emiss 7 (1000tn)	Emiss 8 (1000tn)
3	HLH Sale	0.000	0.000	0.000
4	LLH Sale	0.000	0.000	0.000
5	Spokane River	0.000	0.000	0.000
6	Clark Fork Hy	0.000	0.000	0.000
7	Mid Columbia	0.000	0.000	0.000
8	Colstrip 3	0.000	0.000	0.000
9	Colstrip 4	0.000	0.000	0.000
10	NortheastTurbine	0.148	0.000	0.000
	SumasRock Gas	0.148	0.000	0.000
11	Rathdrum 1	0.074	0.010	0.076
	Rathdrum Gas	0.074	0.010	0.076
12	Rathdrum 2	0.074	0.010	0.076
	Rathdrum Gas	0.074	0.010	0.076
13	RCCCT	0.195	0.026	0.198
	Kingsgate Gas	0.195	0.026	0.198
14	Kettle Falls	0.000	0.000	0.000
15	Potlatch Cogen	0.000	0.000	0.000
16	Upriver Firm	0.000	0.000	0.000
17	BPAexchange	0.000	0.000	0.000
18	PPLExRtn	0.000	0.000	0.000
19	PPLExDel	0.000	0.000	0.000
20	Entitlement	0.000	0.000	0.000
21	CSPE	0.000	0.000	0.000
22	BPA Subscr	0.000	0.000	0.000
23	BPACan Ent	0.000	0.000	0.000
24	WNP3	0.000	0.000	0.000
25	Black Crk	0.000	0.000	0.000
26	BPA5yr Purchase	0.000	0.000	0.000
27	Sempra Purchase	0.000	0.000	0.000
28	Cin Purchase	0.000	0.000	0.000
29	Esi purchase	0.000	0.000	0.000
30	Enr3yr purchase	0.000	0.000	0.000
31	Enr2yr Purchase	0.000	0.000	0.000
32	Puget Sale	0.000	0.000	0.000
33	PGE Capacity	0.000	0.000	0.000
34	Douglas Capacity	0.000	0.000	0.000
35	EWEB Sale	0.000	0.000	0.000
36	SPUD Capacity	0.000	0.000	0.000
37	Clark Sale	0.000	0.000	0.000
38	PPL94 Sale	0.000	0.000	0.000
39	CEPM57 Sale	0.000	0.000	0.000
	SYSTEM EMISSIONS	0.49	0.05	0.35

No.	Group	NOx (1000tn)	Emiss 7 (1000tn)	Emiss 8 (1000tn)
1	HLH Purch	0.000	0.000	0.000
2	LLH Purch	0.000	0.000	0.000
3	HLH Sale	0.000	0.000	0.000
4	LLH Sale	0.000	0.000	0.000
5	Spokane R	0.000	0.000	0.000
6	Clark Fork	0.000	0.000	0.000
7	Mid Col	0.000	0.000	0.000
8	Colstrip	0.000	0.000	0.000
9	Northeast	0.148	0.000	0.000
10	Rathdrum	0.149	0.020	0.151
11	RathdrumCCCT	0.195	0.026	0.198
12	Kettle Fls	0.000	0.000	0.000
13	Cogen	0.000	0.000	0.000
14	Exchange	0.000	0.000	0.000
15	Contract Purchas	0.000	0.000	0.000
16	Contract Sale	0.000	0.000	0.000
SYSTEM EMISSIONS		0.49	0.05	0.35

Time of Day Marginal Cost Summary

Period	Total hours	% of hours	Average Marg Cost
1 On Peak	5024	57.2	37.21
2 Off Peak	3760	42.8	25.31
Total	8784	100.0	32.12

Percent Time at Margin, by Station Group

Groups	Time of Day Periods 1	2	All
1 HLH Purch	22.0	0.0	12.6
2 LLH Purch	0.0	40.9	17.5
3 HLH Sale	78.0	0.0	44.6
4 LLH Sale	0.0	59.1	25.3
5 Spokane R	0.0	0.0	0.0
6 Clark Fork	0.0	0.0	0.0
7 Mid Col	0.0	0.0	0.0
8 Colstrip	0.0	0.0	0.0
9 Northeast	0.0	0.0	0.0
10 Rathdrum	0.0	0.0	0.0
11 RathdrumCCCT	0.0	0.0	0.0
12 Kettle Fls	0.0	0.0	0.0

13 Cogen	0.0	0.0	0.0

Continues...

Groups	Time of Day Periods 1	2	All
14 Exchange	0.0	0.0	0.0
15 Contract Purchas	0.0	0.0	0.0
16 Contract Sale	0.0	0.0	0.0
Dump Power	0.0	0.0	0.0
E.N.S.	0.0	0.0	0.0

Cost at Margin, by Period and Station Group (mills)

Groups	Time of Day Periods 1	2	All
1 HLH Purch	35.0	0.0	35.0
2 LLH Pur-h	0.0	26.5	26.5
3 HLH Sale	37.8	0.0	37.8
4 LLH Sale	0.0	24.5	24.5
5 Spokane R	0.0	0.0	0.0
6 Clark Fork	0.0	0.0	0.0
7 Mid Col	0.0	0.0	0.0
8 Colstrip	0.0	0.0	0.0
9 Northeast	0.0	0.0	0.0
10 Rathdrum	0.0	0.0	0.0
11 RathdrumCCCT	0.0	0.0	0.0
12 Kettle Fls	0.0	0.0	0.0
13 Cogen	0.0	0.0	0.0
14 Exchange	0.0	0.0	0.0
15 Contract Purchas	0.0	0.0	0.0
16 Contract Sale	0.0	0.0	0.0
Dump Power	0.0	0.0	0.0
E.N.S.	0.0	0.0	0.0

Average Hourly Cost Summary

Period	Total hours	% of hours	Total GWh	Average cost
1 On Peak	5024	57.2	5613	5.81
2 Off Peak	3760	42.8	3409	7.06
Total	8784	100.0	9021	6.28

Fuel Use Report

GBtu	Commod	Volume1	Volume2	Demand	Total	¢/MBtu

No.	Fuel	used	$000	$000	$000	$000	$000	average
1	Kingsgate Gas	13294.9	36611	0	0	0	36611.10	275.4
2	Rathdrum Gas	4980.7	13571	1345	0	0	14915.70	299.5

Continues...

No.	Fuel	GBtu used	Commod $000	Volume1 $000	Volume2 $000	Demand $000	Total $000	¢/MBtu average
3	SumasRock Gas	704.4	1855	229	1	0	2085.58	296.1

Station Fuel Report (GBtu used)

No.	Station	SumasRock Gas	Rathdrum Gas	Kingsgate Gas
10	NortheastTurbine	704.4	-	-
11	Rathdrum 1	-	2490.3	-
12	Rathdrum 2	-	2490.3	-
13	RCCCT	-	-	13294.9

Plant Fuel Report (GBtu used)

No.	Plant	SumasRock Gas	Rathdrum Gas	Kingsgate Gas

No.	Station	Max Cap MW	Hours	Fuel	Energy GWh	Fuel GBtu	Fuel Units	Cost $000	Price ¢/MBtu
10	NortheastTurbine	69.0	1012	SumasRock Gas	56.3	704.4		2085.6	296.10
11	Rathdrum 1	88.0	2856	Rathdrum Gas	220.4	2490.3		7457.9	299.47
12	Rathdrum 2	88.0	2856	Rathdrum Gas	220.4	2490.3		7457.9	299.47
13	RCCCT	240.0	7481	Kingsgate Gas	1724.0	13294.9		36611.1	275.38

APPENDIX B

Exhibit 1
Alternative Resource Options
Source: NWPPC (6/00)

		Nominal Life-Cycle Levelized Cost (1999$)			
Project Type	**Fuel Type**	**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
Adv. Coal (PFBC)	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

APPENDIX C

Triple-E Report

December 1, 1999 to March 31, 2000

Avista Utilities Controllers Dept.
Resource Analysis Team
Jason Fletcher
Steve Negretti
Jon Powell

Table of Contents

Introduction

This is the second Triple-E Report produced in fulfillment of Avista Corporation's commitment at the time of the most recent Schedule 90 Tariff approval. This report covers quantitative results for the December 1, 1999 to March 31, 2000 trimester. It includes costs, energy savings, cost-effectiveness and descriptive statistics, Energy Efficiency Tariff Rider balances, measurement and evaluation (M&E) activities, policy updates, and large project disclosures.

Given that much of the basic methodology was covered in the prior report, we have excluded that discussion from this report. We are distributing an electronic version of the previous report for the reader's reference.

In place of the methodology discussion, this report includes approximately three times as many tables than were present in the last report. This is partially to facilitate comparison against the previous August 1 to November 30, 1999 trimester report, but this report also contains a more detailed disaggregation of our impact by jurisdiction and rateclass. Unless otherwise noted, the analytical methodology employed is unchanged from the prior report.

This is the first report where the *SalesLogix* database has been used. Data quality has improved in several areas of this process, including the incorporation of additional information fields and custom reports.

Although the format of the June 2000 Triple-E Board meeting does not include discussion of this report, we would appreciate the opportunity to meet with any Triple-E Board member interested in the full detail of these calculations, either individually or in small groups.

General Analytical Notes

This section has been included to provide insight into analytical details that affect the results of this report. This includes relevant information regarding the treatment of raw data that influences the analysis.

Database and Non-Database Projects

All Avista Corporation energy efficiency projects can be roughly divided into two categories; those that are tracked on a project-by-project basis through the *SalesLogix* database and those that are handled outside the database.

Non-database projects include the Resource Management Partnership Program (RMPP), the Limited Income program and the Natural Gas Awareness Campaign. The analyses of these programs are brought into the report only after a custom evaluation of their costs and benefits are completed.

Database projects are tracked individually through the *SalesLogix* database. Each of the characteristics relevant to the analysis, such as energy savings, non-energy benefits, utility revenue impact and customer cost, are specified based upon each project's unique characteristics.

Database Project Details

Projects tracked through the database include all projects that are individually reviewed, as well as three measures that are analyzed in mass (due to the similarity of many of the project characteristics). Projects reviewed in mass are comprised of the following measures:

1) *VendingMI$ER™*

VendingMI$ER is a control mechanism used to reduce the energy usage of cold drink vending machines. A prescriptive analysis of non-energy benefits resulting from *VendingMI$ER* installations revealed that a significant portion (20%) of the participant benefit from this measure accrue in the form of non-energy (maintenance) savings. These results have been incorporated into the analysis. Since this is a control device, benefits and costs accumulated through *VendingMI$ER* are allocated to the Controls technology.

2) LED Exit Signs

A detailed analysis of LED exit sign annual energy savings was conducted in 1999, with the result being a revision from 240 kWh per sign to 200 kWh per sign. This was primarily based upon a higher inventory of compact fluorescents in the existing inventory than was anticipated. The analysis team has also completed a prescriptive analysis of non-energy benefits resulting from the installation of LED exit signs. The results of this analysis indicate that most (83%) of the participant benefit from this measure accrue in the form of non-energy (maintenance) savings. These results have been incorporated into the analysis. LED exit sign projects were incentivized as New Technologies. As such, benefits and costs accumulated through this program are allocated to the New Technologies measure.

3) LED Traffic Signals

The energy savings from LED traffic signals are tracked by jurisdiction and are incorporated into the analysis. This measure has also been the subject of a non-energy benefit analysis by the analysis team. The results of this analysis indicate that a significant portion (42%) of the participant benefit from this measure accrue in the form of non-energy (maintenance) savings. These results have been incorporated into the analysis. LED traffic signal projects were incentivized as New Technologies. As such, benefits and costs accumulated through this program are allocated to the New Technologies measure.

All Other Projects

All projects tracked within *SalesLogix*, aside from those fitting the categories above, are individually analyzed for their impacts. All characteristics relevant to cost-effectiveness calculations and descriptive statistics are based upon project specific circumstances.

Non-Database Project Details

Resource Management Partnership Program (RMPP)

This program derives resource savings by placing resource managers in individual school districts. The resources affected include electric, natural gas (and other energy), water, sewer and solid waste. For the most part, the non-energy resource impacts occur early during the resource manager's work with the school district. During this particular trimester there were not any significant non-energy resource savings. Energy savings, however, do require the ongoing presence of a district resource manager and do not degrade as much as non-energy resource savings during the period of time that the resource manager is present.

The billing analysis captures the electric and natural gas savings. Non-utility energy impacts are captured on a site-specific basis. The billing analysis for the RMPP program has, over time, resulted in several policies dealing with such contingencies as new construction at an existing school site, the treatment of portable buildings, the aggregation or disaggregation of loads across multiple meters, and so on.

Projects for which the customer receives a direct incentive at a school site where a resource manager is present are removed from the metered savings calculation and credited to the technology that the direct incentive applies toward. For example, the savings from lighting projects at schools are removed from the billed energy savings and credited as an impact of the lighting technology. All billed energy savings remaining after these specific projects have been removed are attributed to resource management activities.

The resource management energy savings can then be characterized by three components; (1) behavioral, such as turning off the lights as necessary, (2) operational, such as utilizing existing controls or modifying the dispatch of end-uses and (3) hardwired measures that, for one reason or another, did not receive a direct incentive. In recognition of the short life of the behavioral and operational measures, in calculating the energy savings for any particular period of time it is assumed that 50% of the energy savings in the prior year and 25% of the energy savings two years preceding were readopted. This effect substantially increases the number of first-year kWh claimed by the program, but it also results in a weighted average life of only four years for these billed energy savings.

At this point we don't have enough data on school districts that have discontinued their resource manager program to verify the accuracy of the measure persistence figures being used.

Limited Income

The Limited Income program obtains energy savings through weatherization improvements and electric to gas conversions (space heat and domestic hot water) for qualified electric utility customers. These savings enter the analysis by applying the results of a detailed billing analysis study completed in 1999 to the water heat and space heat conversions claimed through the program. The weatherization savings are based upon engineering estimates specific to the dwelling. Since the vast majority (99%) of the energy savings in this segment is from fuel-conversions, this has been the focus of the measurement and evaluation efforts to date.

The Limited Income program also funds structural and mechanical repairs to qualified homes, subject to a cap, if they are necessary to ensure the persistence of the energy measures installed, or if they are necessary on a health and human safety basis. It is assumed the benefits derived from these repairs have a non-energy benefit commensurate with their costs.

In this particular trimester no costs associated with these repairs were reported to the analysis team. We will be following up on these impacts in more detail in the next trimester to determine if expenses had been incurred that were not captured as non-energy benefits.

Since these programs are operated in conjunction with community action program (CAP) agencies as part of their overall offerings to this customer segment, the utility costs of the programs are fairly minimal. This leveraging strategy has substantially contributed to a cost-effectiveness higher than would be expected out of this segment.

To clarify the meaning of the various tables reporting on this program, the customer cost is equal to the utility incentive for the limited income programs because all costs associated with energy savings are paid for through the incentive.

Natural Gas Awareness Campaign (NGAC)

The effects of the NGAC are incorporated into the analysis based upon the most recent information on actual residential conversions of space heating, water heating, clothes dryers, ovens and ranges. The first 1,000 space heating conversions are excluded on the basis that these customers are part of the natural adoption in our service territory. This is the only program that excludes the energy savings of free-riders (or natural adopters).

The savings for this program will be adjusted when recently completed survey information is subjected to our energy savings analysis and verification.

Non-Quantifiable Non-Energy Impacts

The analytical group has been working to further develop means of quantifying, where possible, and identifying, where quantification is unreasonable, the non-energy impacts of our projects. The reason for this is twofold; (1) to more accurately represent the cost-effectiveness of the projects and (2) to provide management information about the overall benefits of our programs. This information will be used to refine the marketing of energy efficiency technologies.

At present our quantification of non-energy effects has been limited to two primary components; (1) modifying the capital cost of projects to reflect differences in end-use equipment life and (2) incorporating the maintenance savings. The quantified maintenance savings is almost exclusively related to lighting projects. The non-quantifiable value of these non-energy benefits must be taken into consideration when interpreting much of this analysis, and in particular the TRC test results.

We are endeavoring to improve our ability to identify and quantify these non-energy benefits in the future. One of the changes implemented to address this issue is detailed under the *Notable Projects, Disclosures and Policy Update* section of this report.

Quantitative Results

The following contains descriptions of the methodologies used for completion of the cost-effectiveness analysis and descriptive statistics for the December 1, 1999 to March 31, 2000 trimester. Observations noted in the course of performing this analysis have been noted as well.

Allocation of Utility Costs

This allocation methodology is essentially unchanged from our previous report.

The raw data for utility non-incentive costs comes in the form of actual expenses and journal entries incurred by Tariff Rider accounts. The raw data for direct incentive costs comes in the form of accrual-based expenses, drawn from the *SalesLogix* database. While non-incentive costs represent real expenditures, incentives are de-rated in the same manner as kWh, therms, etc. As such, incentives applied to projects in the Contracted phase are accounted for at 75%, those applied to projects in the Construction phase are accounted for at 95%, and those applied to Completed projects are accounted for at 100%. This methodology was adopted this trimester in an effort to more closely align expenditures with committed funds.

Each expenditure is incurred through an account number specific to the appropriate customer segment, to an "old" program (prior to our shift to the customer segment model), or to general implementation or M&E. In order to attribute all costs to customer segments and technologies, three allocations must be made. The first allocation assigns the expenses associated with the old programs to customer segments. Next, the general implementation and general M&E expense are allocated to customer segments. Last, the utility non-incentive expenses associated with, or allocated to, each customer segment are allocated to individual technologies within that segment.

The overall allocation process is heavily dependent upon the judgement of the individuals performing the allocation. The meaningfulness of these allocations is handicapped by the joint cost nature of many expenditures. An audit, site visit, or marketing effort is generally targeted towards multiple technologies.

Consequently there is the potential for technologies which are cost-effective contributors to the overall portfolio to be cost-ineffective as a result of being burdened with a disproportionate amount of allocated general costs. This should be considered when reviewing both cost-effectiveness ratios and net cost-effectiveness results.

In our previous Triple-E Report we noted that the proportion of utility costs allocated to one of the general categories seemed excessive. The general implementation and general M&E categories were only to be used if a cost could not be reasonably allocated to one or more individual customer segments. We reiterated the need for accurate reporting of these costs to the staff on several occasions after that point. The net result was an insignificant reduction in the proportion of costs charged to general (27.7% to 27.5%). We will continue to follow up on this task, but our tentative interpretation is that the allocation to general costs is appropriate in spite of the initial appearances.

Refer to *Tables 1-4* for utility costs allocated across programs, customer segments, and technologies.

Table 1 Utility Costs Aggregated by Programs and Customer Segments

	Implementation	Incentives[1]	M&E	TOTAL
SEGMENTS				
Agriculture	$ 8,756	$ -	$ -	$ 8,756
Education	$ 120,099	$ 208,958	$ 2,912	$ 331,969
Food Service	$ 12,947	$ 16,200	$ 1,396	$ 30,543
Health Care	$ 11,486	$ 22,715	$ 78	$ 34,279
Hospitality	$ 24,784	$ 25,240	$ 1,241	$ 51,265
Limited Income	$ 12,960	$ 414,492	$ -	$ 427,452
Manufacturing	$ 104,638	$ 127,739	$ 941	$ 233,318
Office	$ 26,709	$ 30,441	$ 3,004	$ 60,154
Residential[2]	$ 77,689	$ 319	$ -	$ 78,007
Retail	$ 21,789	$ 7,657	$ 620	$ 30,066
GENERAL				
General (Implementation)	$ 624,456	$ -	$ -	$ 624,456
General (M&E)	$ -	$ -	$ 87,813	$ 87,813
OTHER EXPENDITURES				
NEEA[3]	$ 3,232	$ 442,005	$ -	$ 445,237
Leases[4]	$ 5,867	$ 44,798	$ -	$ 50,665
OLD PROGRAMS				
LED Traffic Signals	$ 1,112	$ 30,105	$ -	$ 31,217
New Technologies	$ 1,698	$ 28,548	$ -	$ 30,246
Prescriptive HVAC	$ 17	$ -	$ -	$ 17
Prescriptive Lighting	$ 319	$ 1,157	$ 360	$ 1,836
RMPP	$ -	$ 475	$ -	$ 475
Site Specific	$ 25,186	$ 3,020	$ 110	$ 28,316
SS-VFD	$ -	$ 344	$ -	$ 344
Trade Ally	$ 2,779	$ 3,293	$ 110	$ 6,182
TOTAL	**$ 1,086,523**	**$ 1,407,504**	**$ 98,585**	**$ 2,592,611**
BROKEN OUT BY CATEGORY				
Total assigned to segments	$ 421,857	$ 853,761	$ 10,192	$ 1,285,809
Total assigned to general	$ 624,456	$ -	$ 87,813	$ 712,269
Total assigned to other	$ 9,099	$ 486,803	$ -	$ 495,902
Total assigned to old programs	$ 31,111	$ 66,940	$ 580	$ 98,631
TOTAL	**$ 1,086,523**	**$ 1,407,504**	**$ 98,585**	**$ 2,592,611**
CATEGORY AS A PERCENT				
Total assigned to segment	16.3%	32.9%	0.4%	49.6%
Total assigned to general	24.1%	0.0%	3.4%	27.5%
Total assigned to other	0.4%	18.8%	0.0%	19.1%
Total assigned to old programs	1.2%	2.6%	0.0%	3.8%
TOTAL	**41.9%**	**54.3%**	**3.8%**	**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.

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]
Agriculture	$ 8,756	$ -	$ 8,756	$ 14,522	$ 7,082	$ 21,604	$ 425	$ -	$ 425	$ 23,703	$ 7,082	$ -	$ 30,784	70.2%
Education	$ 120,099	$ 2,912	$ 123,011	$ 116,178	$ 11,870	$ 128,047	$ 10,538	$ 79	$ 10,617	$ 246,815	$ 14,861	$ 237,932	$ 499,608	25.6%
Food Service	$ 12,947	$ 1,396	$ 14,343	$ 29,044	$ 8,253	$ 37,297	$ 480	$ 47	$ 527	$ 42,471	$ 9,696	$ 16,200	$ 68,366	54.6%
Health Care	$ 11,486	$ 78	$ 11,564	$ 58,089	$ 8,809	$ 66,898	$ 5,501	$ 51	$ 5,552	$ 75,076	$ 8,938	$ 22,715	$ 106,729	62.7%
Hospitality	$ 24,784	$ 1,241	$ 26,025	$ 87,133	$ 10,354	$ 97,487	$ 480	$ 47	$ 527	$ 112,397	$ 11,642	$ 25,783	$ 149,822	65.1%
Limited Income	$ 12,960	$ -	$ 12,960	$ 72,611	$ 9,656	$ 82,267	$ -	$ -	$ -	$ 85,571	$ 9,656	$ 414,492	$ 509,718	16.1%
Manufacturing	$ 104,638	$ 941	$ 105,579	$ 116,178	$ 11,870	$ 128,047	$ 8,422	$ 46	$ 8,469	$ 229,238	$ 12,857	$ 161,816	$ 403,911	31.7%
Office	$ 26,709	$ 3,004	$ 29,713	$ 58,089	$ 8,627	$ 66,716	$ 2,627	$ 110	$ 2,737	$ 87,425	$ 11,741	$ 33,228	$ 132,394	50.4%
Residential	$ 77,689	$ -	$ 77,689	$ 29,044	$ 5,355	$ 34,399	$ 17	$ -	$ 2,822	$ 106,750	$ 5,355	$ 319	$ 112,424	30.6%
Retail	$ 21,789	$ 620	$ 22,409	$ 43,567	$ 5,940	$ 49,507	$ 2,622	$ 200	$ 2,822	$ 67,978	$ 6,760	$ 8,217	$ 82,954	59.7%
	$ 421,857	$ 10,192	$ 432,049	$ 624,456	$ 87,813	$ 712,269	$ 31,111	$ 580	$ 34,496	$ 1,077,424	$ 98,585	$ 920,701	$ 2,096,709	

[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
Agriculture	$ -	$ -	$ -	$ 12,314	$ -	$ 6,157	$ -	$ -	$ 12,314	$ -	$ -	$ -	$ -	$ -	$ 30,784	1.5
Education	$ -	$ -	$ -	$ 60,806	$ 44,723	$ -	$ 262,220	$ -	$ -	$ 38,603	$ -	$ 84,110	$ 9,346	$ -	$ 499,608	23.8
Food Service	$ -	$ -	$ -	$ 21,096	$ 20,867	$ -	$ 15,650	$ 5,217	$ -	$ 320	$ -	$ -	$ 5,217	$ -	$ 68,366	3.3
Health Care	$ -	$ -	$ -	$ 8,844	$ 17,687	$ 4,422	$ 17,687	$ 4,422	$ 4,422	$ 31,559	$ -	$ 13,265	$ 4,422	$ -	$ 106,729	5.1
Hospitality	$ -	$ -	$ -	$ 16,628	$ 31,010	$ -	$ 52,441	$ -	$ -	$ 49,742	$ -	$ -	$ -	$ -	$ 149,822	7.1
Limited Income	$ 133,067	$ 34,228	$ -	$ -	$ 325,904	$ -	$ -	$ -	$ 5,793	$ -	$ -	$ -	$ 10,726	$ -	$ 509,718	24.3
Manufacturing	$ -	$ -	$ 28,977	$ 33,328	$ 63,802	$ 22,269	$ 29,613	$ 14,385	$ 27,869	$ 183,871	$ -	$ -	$ -	$ -	$ 403,911	19.3
Office	$ -	$ -	$ -	$ 26,913	$ 27,045	$ -	$ 46,386	$ -	$ 9,015	$ 18,781	$ -	$ -	$ (4,761)	$ 9,015	$ 132,394	6.3
Residential	$ 11,264	$ 70,465	$ -	$ 319	$ 30,375	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 112,424	5.4
Retail	$ -	$ -	$ -	$ 10,430	$ 20,383	$ -	$ 40,490	$ -	$ -	$ 1,460	$ -	$ -	$ 10,192	$ -	$ 82,954	4.0
TOTAL $	$ 144,331	$ 104,694	$ 28,977	$ 190,475	$ 581,596	$ 32,848	$ 464,487	$ 24,023	$ 59,413	$ 324,336	$ -	$ 97,375	$ 35,140	$ 9,015	$ 2,096,709	100.0
% of portfolio	6.9%	5.0%	1.4%	9.1%	27.7%	1.6%	22.2%	1.1%	2.8%	15.5%	0.0%	4.6%	1.7%	0.4%	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.

Exh. 6 / Schedule 2 Page 44 of 84
R. Lafferty
Avista Corporation

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
Agriculture	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
Education	$ -	$ -	$ -	$ 32,570	$ (2,005)	$ -	$ 178,110	$ -	$ -	$ 29,258	$ -	$ -	$ -	$ -	$ 237,932	25.8%
Food Service	$ -	$ -	$ -	$ 15,880	$ -	$ -	$ -	$ -	$ -	$ 320	$ -	$ -	$ -	$ -	$ 16,200	1.8%
Health Care	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 22,715	$ -	$ -	$ -	$ -	$ 22,715	2.5%
Hospitality	$ -	$ -	$ -	$ 1,123	$ -	$ -	$ 21,432	$ -	$ -	$ 3,228	$ -	$ -	$ -	$ -	$ 25,783	2.8%
Limited Income	$ 129,204	$ -	$ -	$ -	$ 274,562	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,726	$ -	$ 414,492	45.0%
Manufacturing	$ -	$ -	$ 6,565	$ 5,456	$ 7,092	$ 756	$ 972	$ -	$ -	$ 140,974	$ -	$ -	$ -	$ -	$ 161,816	17.6%
Office	$ -	$ -	$ -	$ 8,883	$ -	$ -	$ 19,341	$ -	$ -	$ 9,766	$ -	$ -	$ (4,761)	$ -	$ 33,228	3.6%
Residential	$ -	$ -	$ -	$ 319	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 319	0.0%
Retail	$ -	$ -	$ -	$ 238	$ -	$ -	$ 6,518	$ -	$ -	$ 1,460	$ -	$ -	$ -	$ -	$ 8,217	0.9%
TOTAL $	$ 129,204	$ -	$ 6,565	$ 64,489	$ 279,649	$ 756	$ 226,373	$ -	$ -	$ 207,720	$ -	$ -	$ 5,965	$ -	$ 920,701	100.0%
% of portfolio	14.0%	0.0%	0.7%	7.0%	30.4%	0.1%	24.6%	0.0%	0.0%	22.6%	0.0%	0.0%	0.6%	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.

Exh. 6 / Schedule 2
R. Lafferty
Avista Corporation

Treatment of De-Rated Project Results

As previously mentioned, projects in the Contracted and Construction phases are credited with 75% and 95% of the engineering estimates. This applies to kWh savings, therm savings, direct incentives, non-energy benefits, and customer costs.

Energy Savings

During this trimester Avista participated in over 12.3 million kWh of energy savings, which resulted in an increase of approximately 137,000 therms of natural gas usage. This represents the progress of projects within the "pipeline" of the five sequential phases during the trimester.

As always, the net therm savings incorporate the additional therm usage of electric to natural gas conversions. The largest therm contributors this trimester were the Natural Gas Awareness Campaign and the conversion component of the Limited Income program.

Avista Corporation's participation in the Northwest Energy Efficiency Alliance is within this report for purposes of calculating utility costs, but has been excluded for cost-effectiveness purposes. This is due to the lack of definable energy savings at this point in time. During this trimester, NEEA accounted for 17.2% of our utility costs.

These calculations of energy savings do not include any estimates of free-riders, free-drivers, or any market transformation effects. At this point it is unclear how these effects will influence the total energy savings of the portfolio. We will be investigating this question in the near future in compliance with our Idaho general ratecase order.

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

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
Agriculture	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0%
Education	-	-	-	470,952	5,223	-	2,948,586	-	-	367,783	-	1,108,974	-	-	4,901,518	39.8%
Food Service	-	-	-	245,861	21,240	-	-	-	-	3,200	-	-	-	-	270,301	2.2%
Health Care	-	-	-	-	-	-	-	-	-	216,525	-	-	-	-	216,525	1.8%
Hospitality	-	-	-	12,375	-	-	253,767	-	-	36,600	-	-	-	-	302,742	2.5%
Limited Income	641,478	-	-	-	1,295,502	-	-	-	-	-	-	-	20,054	-	1,957,034	15.9%
Manufacturing	-	-	122,788	91,778	124,507	15,127	117,066	-	-	1,168,019	-	-	-	-	1,639,284	13.3%
Office	-	-	-	114,520	34,493	-	350,821	-	-	103,021	-	-	(59,651)	-	543,204	4.4%
Residential	460,187	-	-	6,755	1,790,841	-	-	-	-	-	-	-	-	-	2,257,783	18.3%
Retail	-	-	-	2,625	-	-	214,646	-	-	14,607	-	-	-	-	231,878	1.9%
TOTAL kWh	1,101,665	-	122,788	944,867	3,271,805	15,127	3,884,886	-	-	1,909,755	-	1,108,974	(39,597)	-	12,320,271	100.0%
% of portfolio	8.9%	0.0%	1.0%	7.7%	26.6%	0.1%	31.5%	0.0%	0.0%	15.5%	0.0%	9.0%	-0.3%	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
Agriculture	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0%
Education	-	-	-	8,964	-	-	(10,809)	-	-	(51)	-	40,299	-	-	38,404	-28.1%
Food Service	-	-	-	-	672	-	-	-	-	-	-	-	-	-	672	-0.5%
Health Care	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0%
Hospitality	-	-	-	-	-	-	(319)	-	-	-	-	-	-	-	(319)	0.2%
Limited Income	(17,510)	-	-	-	(35,362)	-	-	-	-	-	-	-	(547)	-	(53,419)	39.1%
Manufacturing	-	-	-	-	-	-	(138)	-	-	-	-	-	-	-	(138)	0.1%
Office	-	-	-	-	-	-	(2,583)	-	-	-	-	-	(21,904)	-	(24,487)	17.9%
Residential	(19,633)	-	-	-	(76,402)	-	-	-	-	-	-	-	-	-	(96,034)	70.3%
Retail	-	-	-	-	-	-	(1,199)	-	-	-	-	-	-	-	(1,199)	0.9%
TOTAL Therms	(37,143)	-	-	8,964	(111,092)	-	(15,048)	-	-	(51)	-	40,299	(22,451)	-	(136,521)	100.0%
% of portfolio	27.2%	0.0%	0.0%	-6.6%	81.4%	0.0%	11.0%	0.0%	0.0%	0.0%	0.0%	-29.5%	16.4%	0.0%	100.0%	

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

Customer Costs and Non-Energy Benefits

A summary of customer costs incurred to achieve the energy savings portion of the projects captured in this report has been included. The raw customer costs have been modified to exclude non-electric components of customer projects, and to appropriately match the measure life of base-case and high-efficiency alternatives. Customer cost figures listed are also not adjusted for direct incentives granted by Avista Corporation.

These customer costs substantially affect the total resource cost test and the participant test. Customer costs amount to approximately two-thirds of the total resource and participant costs.

The non-energy benefit data reflects the quantifiable non-energy benefits accruing to the energy efficiency projects. To date these quantifiable non-energy benefits are limited to maintenance savings inherent in LED exit sign, LED traffic signal, *VendingMI$ER*, and non-residential lighting projects.

We are continuing our research to quantify other non-energy benefits such as productivity, safety, retail sales and so forth. To date we have not found a sufficient body of research that would reasonably substantiate the numerical claims that have been made in these areas. These as yet non-quantifiable non-energy benefits are clearly major influences on the adoption of energy efficiency measures and on the cost-effectiveness of our portfolio, and they are actively used in marketing these measures to our customers.

We are reviewing the database projects in greater depth to obtain information about increased production and other relatively easily quantifiable values. We will also be working to better identify what non-energy benefits accrue to what measures, even if those benefits are non-quantifiable.

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

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
Agriculture	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
Education	$ -	$ -	$ -	$ 28,052.65	$ -	$ -	$ 535,510.51	$ -	$ -	$ 542,105.01	$ -	$ -	$ -	$ -	$ 1,105,668.18	62.3%
Food Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,775.07	$ -	$ -	$ -	$ -	$ 4,775.07	0.3%
Health Care	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 190,704.18	$ -	$ -	$ -	$ -	$ 190,704.18	10.7%
Hospitality	$ -	$ -	$ -	$ 37,582.47	$ -	$ -	$ 24,221.83	$ -	$ -	$ 54,614.81	$ -	$ -	$ -	$ -	$ 116,419.11	6.6%
Limited Income	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
Manufacturing	$ -	$ -	$ -	$ 6,406.42	$ -	$ -	$ 8,065.60	$ -	$ -	$ 1,790.65	$ -	$ -	$ -	$ -	$ 16,262.67	0.9%
Office	$ -	$ -	$ -	$ 6,584.83	$ -	$ -	$ 101,048.63	$ -	$ -	$ 153,728.78	$ -	$ -	$ -	$ -	$ 261,362.23	14.7%
Residential	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
Retail	$ -	$ -	$ -	$ 219.49	$ -	$ -	$ 58,252.93	$ -	$ -	$ 21,796.68	$ -	$ -	$ -	$ -	$ 80,269.11	4.5%
TOTAL NEB $	$ -	$ -	$ -	$ 78,845.87	$ -	$ -	$ 727,099.51	$ -	$ -	$ 969,515.18	$ -	$ -	$ -	$ -	$ 1,775,460.54	100.0%
% of portfolio	0.0%	0.0%	0.0%	4.4%	0.0%	0.0%	41.0%	0.0%	0.0%	54.6%	0.0%	0.0%	0.0%	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
Agriculture	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
Education	$ -	$ -	$ -	$ 118,768.04	$ (3,243.50)	$ -	$ 526,832.10	$ -	$ -	$ 90,483.60	$ -	$ -	$ -	$ -	$ 732,840.24	29.1%
Food Service	$ -	$ -	$ -	$ 31,760.25	$ -	$ -	$ -	$ -	$ -	$ 787.28	$ -	$ -	$ -	$ -	$ 32,547.53	1.3%
Health Care	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 47,961.40	$ -	$ -	$ -	$ -	$ 47,961.40	1.9%
Hospitality	$ -	$ -	$ -	$ 1,310.93	$ -	$ -	$ 29,713.11	$ -	$ -	$ 9,004.49	$ -	$ -	$ -	$ -	$ 40,028.52	1.6%
Limited Income	$ 129,204.43	$ -	$ -	$ -	$ 274,561.59	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,725.52	$ -	$ 414,491.54	16.5%
Manufacturing	$ -	$ -	$ 15,269.35	$ 9,474.70	$ 29,059.00	$ -	$ 8,854.00	$ -	$ -	$ 650,579.23	$ -	$ -	$ -	$ -	$ 713,236.28	28.3%
Office	$ -	$ -	$ -	$ 23,927.15	$ 5,000.00	$ -	$ 6,021.75	$ -	$ -	$ 25,345.66	$ -	$ -	$ 86,042.00	$ -	$ 146,336.56	5.8%
Residential	$ 145,514.63	$ -	$ -	$ 750.00	$ 234,674.41	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 380,939.04	15.1%
Retail	$ -	$ -	$ -	$ 282.15	$ -	$ -	$ 5,745.41	$ -	$ -	$ 3,593.68	$ -	$ -	$ -	$ -	$ 9,621.24	0.4%
TOTAL NEB $	$ 274,719.06	$ -	$ 15,269.35	$ 186,273.21	$ 540,051.50	$ -	$ 576,166.37	$ -	$ -	$ 827,755.34	$ -	$ -	$ 96,767.52	$ -	$ 2,517,802.25	100.0%
% of portfolio	10.9%	0.0%	0.6%	7.4%	21.4%	0.0%	22.9%	0.0%	0.0%	32.9%	0.0%	0.0%	3.8%	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 and Descriptive Statistics

The following tables contain cost-effectiveness statistics for this trimester for all four standard practice tests. Also included are net benefits for each test by customer segment and technology. Net benefits have been included to give additional insight into the significance of each segment and technology.

The Total Resource Cost (TRC) ratio is essentially unchanged from the previous trimester (1.12 to 1.11). It is too early to ascertain if we were correct in our expectation that TRC cost-effectiveness would increase as the one-time costs incurred in the August 1 to November 30, 1999 trimester were completed. As of yet, we do not have enough history of calculating cost-effectiveness on a trimesterly basis to determine if the normal variation could conceal a meaningful increase in cost-effectiveness.

The Utility Cost Test (UCT) ratio has fallen significantly from the previous trimester (2.11 to 1.11). As mentioned previously, we are uncertain as to the normal variation that we should expect when cost-effectiveness is calculated on a trimesterly basis, but it seems unlikely that a change of this magnitude is within normal variation. It is more likely that it is the result of the imposition of the new Schedule 90 Tariff and the higher incentives contained therein. Supporting this hypothesis is the fact that the proportion of "old programs" (those projects being completed under the old tariff) has fallen significantly from the previous trimester.

It is possible that the decline in the UCT ratio will continue into the next trimester, as the last of the "old programs" reach completion and the project pipeline is composed completely of the higher incentive projects being completed under the new tariff. If this is the case, a management review of the portfolio would be warranted to address the issue of identifying what the minimum acceptable UCT ratio is and how the portfolio can be managed to achieve it.

The participant test ratio has moved from 2.98 to 4.46 in the last trimester. This increase lends a certain amount of corroboration to the theory that the UCT ratio is falling as a result of increased utility direct incentives. It may also imply that the free-ridership ratio has improved as a result of offering enhanced incentives (the larger the incentive and the higher the participant ratio the more likely it is that the program made the difference in adoption of the measure). The tiering of the incentives based upon simple payback may further enhance that effect.

These interpretations will be incorporated into the free-ridership analysis that the Company was requested to perform under the recently completed Idaho ratecase order. This may impact the timing of the study. Having established the hypothesis that the new programs appear to be impacting the free-ridership ratio, it would be necessary to segment "old" programs from "new" programs to develop an accurate view of free-ridership.

The non-participant test ratio (also called the rate impact measure) experienced a slight decline from 0.44 to 0.33. As had been previously indicated, Avista is mathematically guaranteed to fail this test (have a ratio below 1.0) as long as our rates are above our avoided costs. The Avista response has been to offer a broad enough program portfolio to provide every customer the opportunity to directly or indirectly benefit from our portfolio. The meaning of a non-participant test is diminished as these program benefits become more widely distributed.

Comparison to the previous trimester indicates a slight increase in the customer cost per kWh (18 cents/kWh to 20 cents/kWh). A change of this magnitude is likely to be within the normal variation of a trimesterly report.

The utility implementation cost also increased from 7 cents/kWh to 10 cents/kWh. This is attributable to the reduction in energy savings from 14.2 million kWh to 12.3 million kWh. The utility implementation costs actually fell from the previous trimester.

We have added a measure of incentive cost per kWh to assist in diagnosing the UCT ratio issue, as previously discussed. The increase in incentive cost per kWh from five cents to seven cents reflects the most recent change to the Schedule 90 Tariff.

Refer to *Tables 9 and 10* for summaries of cost-effectiveness for all four standard practice tests by customer segments and technologies.

Refer to *Tables 11 and 12* for summaries of net benefits for all four standard practice tests by customer segments and technologies.

Refer to *Table 13* for further details on the calculation of the cost-effectiveness rations, as well as some useful descriptive statistics.

Table 9 — Cost-Effectiveness Statistics by Customer Segment

	Total Resource Cost Test	Utility Cost Test	Participant Test	Non-Participant Test
Agriculture	-	-	N/A	-
Education	1.96	1.70	5.89	0.36
Food Service	0.62	0.70	7.05	0.26
Health Care	1.74	0.37	10.35	0.22
Hospitality	1.06	0.38	16.42	0.22
Limited Income	0.91	0.91	N/A	0.29
Manufacturing	0.34	0.75	0.90	0.34
Office	1.33	0.49	3.84	0.27
Residential	0.92	4.03	3.18	0.37
Retail	1.46	0.51	127.18	0.24
PORTFOLIO	1.11	1.11	4.46	0.33

Table 10 — Cost-Effectiveness Statistics by Technology

	Total Resource Cost Test	Utility Cost Test	Participant Test	Non-Participant Test
Appliances	0.86	1.73	4.06	0.34
Assistive Technologies	-	-	N/A	-
Compressed Air	0.56	0.73	3.96	0.33
Controls	0.87	0.73	3.74	0.33
HVAC	0.83	1.20	7.49	0.32
Industrial Process	0.08	0.08	(8.01)	0.07
Lighting	1.75	1.51	6.54	0.35
Monitoring	-	-	N/A	-
Motors	-	-	N/A	-
New Tech	1.42	1.14	2.56	0.39
Renewables	N/A	N/A	N/A	N/A
Resource Management	1.29	1.29	N/A	0.29
Shell	(0.31)	(1.11)	(0.77)	(0.12)
Sustainable Building	-	-	N/A	-
PORTFOLIO	1.11	1.11	4.46	0.33

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
Agriculture	$	(30,784)	$	(30,784)	$	-	$	(30,784)
Education	$	958,778	$	347,818	$	2,417,921	$	(1,448,409)
Food Service	$	(32,371)	$	(20,798)	$	98,941	$	(130,319)
Health Care	$	97,913	$	(67,544)	$	236,051	$	(138,138)
Hospitality	$	9,879	$	(92,295)	$	219,638	$	(210,100)
Limited Income	$	(46,251)	$	(46,251)	$	1,276,036	$	(1,445,800)
Manufacturing	$	(634,407)	$	(99,250)	$	(52,563)	$	(581,963)
Office	$	81,059	$	(67,195)	$	320,826	$	(274,598)
Residential	$	(40,061)	$	340,559	$	827,902	$	(1,103,064)
Retail	$	38,408	$	(40,457)	$	177,215	$	(140,418)
PORTFOLIO	$	**402,162**	$	**223,803**	$	**5,521,968**	$	**(5,503,595)**

Table 12 **Net Benefits by Technology**

		Total Resource Cost Test		Utility Cost Test		Participant Test		Non-Participant Test
Appliances	$	(39,944)	$	105,571	$	444,788	$	(583,667)
Assistive Technologies	$	(104,694)	$	(104,694)	$	-	$	(104,694)
Compressed Air	$	(16,586)	$	(7,881)	$	25,756	$	(42,341)
Controls	$	(39,177)	$	3,781	$	333,908	$	(365,394)
HVAC	$	(146,462)	$	113,941	$	1,689,879	$	(2,093,761)
Industrial Process	$	(29,492)	$	(30,249)	$	6,817	$	(36,309)
Lighting	$	612,692	$	236,186	$	1,941,179	$	(1,342,545)
Monitoring	$	(24,023)	$	(24,023)	$	-	$	(24,023)
Motors	$	(59,413)	$	(59,413)	$	-	$	(59,413)
New Tech	$	394,861	$	45,380	$	969,313	$	(574,515)
Renewables	$	-	$	-	$	-	$	-
Resource Management	$	28,527	$	28,527	$	270,812	$	(229,678)
Shell	$	(165,112)	$	(74,309)	$	(160,482)	$	(38,240)
Sustainable Building	$	(9,015)	$	(9,015)	$	-	$	(9,015)
PORTFOLIO	$	**402,162**	$	**223,803**	$	**5,521,968**	$	**(5,503,595)**

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	$ 2,066,877	$ 599,880	$ 2,666,757
Non-Energy benefits	$ 1,775,461	$ -	$ 1,775,461
Natural Gas avoided cost	$ (209,832)	$ (136,413)	$ (346,244)
TRC benefits	$ 3,632,506	$ 463,467	$ 4,095,973
Non-incentive utility cost	$ 1,080,782	$ 95,227	$ 1,176,009
Customer cost	$ 2,103,311	$ 414,492	$ 2,517,802
TRC costs	$ 3,184,093	$ 509,718	$ 3,693,811
TRC ratio	1.14	0.91	1.11
Net TRC benefits	$ 448,413	$ (46,251)	$ 402,162

Utility Cost Test	Regular Income portfolio	Limited Income portfolio	Overall portfolio
Electric avoided cost	$ 2,066,877	$ 599,880	$ 2,666,757
Natural Gas avoided cost	$ (209,832)	$ (136,413)	$ (346,244)
UCT benefits	$ 1,857,045	$ 463,467	$ 2,320,512
Non-incentive utility cost	$ 1,080,782	$ 95,227	$ 1,176,009
Incentive cost	$ 506,209	$ 414,492	$ 920,701
UCT costs	$ 1,586,991	$ 509,718	$ 2,096,709
UCT ratio	1.17	0.91	1.11
Net UCT benefits	$ 270,054	$ (46,251)	$ 223,803

Participant Test	Regular Income portfolio	Limited Income portfolio	Overall portfolio
Bill Reduction	$ 4,067,573	$ 1,276,036	$ 5,343,609
Non-Energy benefits	$ 1,775,461	$ -	$ 1,775,461
Participant benefits	$ 5,843,033	$ 1,276,036	$ 7,119,070
Customer project cost	$ 2,103,311	$ 414,492	$ 2,517,802
Incentive received	$ 506,209	$ 414,492	$ 920,701
Participant costs	$ 1,597,101	$ -	$ 1,597,101
Participant Test ratio	3.66	N/A	4.46
Net Participant benefits	$ 4,245,932	$ 1,276,036	$ 5,521,968

Non-Participant Test	Regular Income portfolio	Limited Income portfolio	Overall portfolio
Electric avoided cost savings	$ 2,066,877	$ 599,880	$ 2,666,757
Non-Part benefits	$ 2,066,877	$ 599,880	$ 2,666,757
Revenue loss	$ 4,537,681	$ 1,535,961	$ 6,073,642
Non-incentive utility cost	$ 1,080,782	$ 95,227	$ 1,176,009
Customer incentives	$ 506,209	$ 414,492	$ 920,701
Non-Part costs	$ 6,124,672	$ 2,045,679	$ 8,170,351
Non-Part. ratio	0.34	0.29	0.33
Net Non-Part. benefits	$ (4,057,795)	$ (1,445,800)	$ (5,503,595)

Descriptive Statistics	Regular Income portfolio	Limited Income portfolio	Overall portfolio
Annual kWh savings	10,363,237	1,957,034	12,320,271
Customer cost/kWh	$ 0.20	$ 0.21	$ 0.20
Non-incentive utility cost/kWh	$ 0.10	$ 0.05	$ 0.10
Electric avoided cost/kWh	$ 0.20	$ 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 methodology of this calculation has not changed since the previous Triple-E Report. One error, the omission of the effect of the one-month lag specified in the 1994 Accounting Guidelines amounting to $10,949, has been corrected.

In the last twelve months Avista has:

- spent $2.2 million more than it has collected as Tariff Rider revenues ($1.4 million in Washington, $0.8 million in Idaho)
- incurred expenditures in excess of rider revenues by 47% (41% in Washington, 64% in Idaho)
- reduced the Tariff Rider balance by $1.9 million ($1.2 million in Washington, $0.7 million in Idaho)
- cut the balance by 45% (41% in Washington, 53% in Idaho) and
- incorporated within the balance $318,000 of interest assessments ($215,000 Washington, $103,000 Idaho).

This progress towards Avista Corporation's objective of reducing the balance through funding cost-effective energy efficiency may somewhat overstate the progress to date due to a disproportionate amount of NEEA invoices paid during this moving average. However, even taking this into consideration, it does represent a significant increase in energy efficiency activity on the part of the Company.

The TRC cost-effectiveness during this trimester indicates that it is not only an increase in expenditures, but that the incremental expenditures do have energy savings commensurate with their costs.

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	Idaho DSM Expenditures	Idaho DSM Revenues	Idaho Beginning DSM balance	Idaho Ending DSM balance	Idaho Interest	Idaho Ending bal. with interest
January 1999	$ 171,037	$ 371,658	$ 2,617,016	$ 2,817,637	$ 10,950	$ 2,828,586	$ 70,147	$ 161,905	$ 1,053,579	$ 1,145,337	$ 2,385	$ 1,147,722
February	$ 188,863	$ 321,493	$ 2,828,586	$ 2,961,216	$ 21,668	$ 2,982,885	$ 100,620	$ 157,171	$ 1,147,722	$ 1,204,273	$ 8,767	$ 1,213,040
March	$ 418,803	$ 292,771	$ 2,982,885	$ 2,858,853	$ 23,084	$ 2,881,937	$ 57,166	$ 143,563	$ 1,213,040	$ 1,299,438	$ 9,378	$ 1,308,815
April	$ 781,856	$ 266,606	$ 2,881,937	$ 2,366,688	$ 23,291	$ 2,389,979	$ 268,935	$ 132,749	$ 1,308,815	$ 1,172,629	$ 10,017	$ 1,182,647
May	$ 333,268	$ 247,454	$ 2,389,979	$ 2,304,165	$ 20,927	$ 2,325,092	$ 131,689	$ 121,686	$ 1,182,647	$ 1,172,644	$ 9,894	$ 1,182,538
June	$ 283,079	$ 268,981	$ 2,325,092	$ 2,308,994	$ 18,716	$ 2,327,710	$ 87,749	$ 121,986	$ 1,182,538	$ 1,216,775	$ 9,391	$ 1,226,165
July	$ 315,854	$ 237,115	$ 2,327,710	$ 2,248,971	$ 18,476	$ 2,267,447	$ 82,662	$ 121,018	$ 1,226,165	$ 1,264,521	$ 9,566	$ 1,274,087
August	$ 470,627	$ 272,035	$ 2,267,447	$ 2,068,855	$ 18,248	$ 2,087,102	$ 146,099	$ 82,983	$ 1,274,087	$ 1,210,971	$ 9,931	$ 1,220,902
September	$ 220,534	$ 302,045	$ 2,087,102	$ 2,168,613	$ 17,289	$ 2,185,903	$ 85,885	$ 86,004	$ 1,220,902	$ 1,221,021	$ 9,908	$ 1,230,929
October	$ 333,763	$ 260,080	$ 2,185,903	$ 2,112,220	$ 16,968	$ 2,129,188	$ 304,545	$ 81,571	$ 1,230,929	$ 1,007,955	$ 9,736	$ 1,017,691
November	$ 174,943	$ 263,916	$ 2,129,188	$ 2,218,161	$ 17,137	$ 2,235,298	$ 167,877	$ 85,391	$ 1,017,691	$ 935,206	$ 8,927	$ 944,132
December	$ 759,356	$ 317,111	$ 2,235,298	$ 1,793,053	$ 17,333	$ 1,810,386	$ 306,838	$ 102,257	$ 944,132	$ 739,552	$ 7,786	$ 747,338
January 2000	$ 261,424	$ 350,395	$ 1,810,386	$ 1,899,357	$ 16,061	$ 1,915,419	$ 174,092	$ 93,727	$ 747,338	$ 666,973	$ 6,713	$ 673,686
February	$ 296,815	$ 318,411	$ 1,915,419	$ 1,937,014	$ 14,791	$ 1,951,806	$ 92,648	$ 124,369	$ 673,686	$ 705,407	$ 5,639	$ 711,046
March	$ 566,151	$ 296,857	$ 1,951,805	$ 1,682,511	$ 15,360	$ 1,697,871	$ 200,639	$ 95,373	$ 711,048	$ 605,780	$ 5,499	$ 611,278
1999 totals	$ 4,449,983	$ 3,419,265			$ 224,088		$ 1,810,210	$ 1,398,284			$ 105,685	
2000 totals	$ 1,124,390	$ 965,663			$ 46,212		$ 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	$ 3,870,595	$ 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	$ 484,956	$ 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	$ 389,483	$ 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.

Analysis / Measurement and Evaluation Summary

For this reporting period, seven projects and programs were selected for in-depth review. The following summaries highlight the findings of each review.

For confidentiality reasons, customer names have been omitted except in the case of governmental organizations. More detailed reports are available upon request.

The analysis team continually endeavors to present to the Triple-E Board an accurate portrayal of Avista Utilities' energy efficiency activities. Comments and suggestions regarding both the content and format of this report are always welcome.

Program Updates

Resource Management Partnership Program (RMPP)

The billing analysis of all school districts participating in RMPP were reviewed and revised to meet the most recent policy decisions on these calculations.

It was notable that no non-energy benefits have been identified during the trimester. Follow-up indicated that this was an accurate reflection of the programs current activity. Most of the participating school districts have already realized the majority of the cost-effective non-energy resource savings.

One meter located at Mead High School is currently under investigation. The usage on the meter has dramatically increased to a level far beyond that which is reasonable for the tennis court application that it was intended for. We are almost certain that the nearby construction of a major addition to the school is the cause of the aberration. If we can positively identify construction as the source of the usage we will revise the billed savings calculation upward by that amount.

VendingMI$ER™ Program

In the November 1999 Triple-E Report, it was reported that Avista was embarking on an aggressive project to install *VendingMI$ER* control units on hundreds of cold drink vending machines within the service territory. As of March 31, 2000, over 300 individual *VendingMI$ER* units were installed, or in the process of being installed, on vending machines throughout Avista Utilities' service territory.

The *VendingMI$ER* control unit is manufactured by Bayview Technology Group, Inc. It is designed to operate as an intelligent power controller for cold product vending machines. It is not recommended for use with vending machines containing perishable products. The *VendingMI$ER* uses a passive infrared sensor to shut down the controlled vending machine when the area surrounding the machine has been vacant for 15 minutes. The *VendingMI$ER* will periodically re-power the vending machine to ensure the product stays cold.

Preliminary monitoring conducted by Avista has shown an estimated annual energy savings of 1,500 kWh per unit. These results closely match studies performed by Bayview and other analysis, including a study performed by Rutgers University. These preliminary studies form the basis for the annual savings claim of 1,500 kWh per *VendingMI$ER* installation. Avista has adopted this figure for a prescriptive program, with the understanding that further data collection would occur and savings claims would be adjusted accordingly.

The *VendingMI$ER* is appropriately considered a new technology since a microprocessor based control of vending machines is new and such a technology was non-existent in the Avista service territory prior to the launch of this program. Under the existing tariff, any new technology project producing 1,500 kWh in annual savings would be eligible for an incentive of $150.00 to $210.00,depending on the project simple payback. For this program Avista has chosen to purchase *VendingMI$ER* units on behalf of customers, in lieu of direct financial incentives. The cost per *VendingMI$ER* unit is $135.

Avista Utilities is currently in the midst of extensive monitoring of the *VendingMI$ER* control unit. Data acquisition began in December of 1999. Monitoring is currently being performed on dozens of cold drink vending machines at customer locations throughout the service territory. Datalogging of vending machines without control units installed, as well as those under *VendingMI$ER* control, are underway. Data acquisition will continue until a large enough population has been observed to provide us with adequate data for calculation of average annual kWh savings. Datalogging results will be used to adjust annual energy savings claimed by Energy Services if necessary.

The results of datalogging efforts for the *VendingMI$ER* program thus far have indicated that the savings may average closer to 800 kWh per installation. However, given the substantial variance of savings across projects we have decided to delay any adjustment until we can expand the sample size. We will revisit this topic in the next Triple-E Report, with the benefits of a larger sample size.

The analysis team intends to capture data on individual electricity consumption for as long as a year, both pre and post installation. We are also striving to capture energy consumption on a variety of vending machine makes and models, dispensing cold products of various sizes and in a variety of locations.

Individual Project Reviews

Project Status:	Completed August of 1999
Program/Segment:	Trade Ally and New Technology Programs
Technology:	Canopy Lighting and LED Strip Lighting
Site:	Service Station and Convenience Store
Location:	Colville, Washington

<u>Study Summary</u>

- This study resulted in no impact on energy savings estimates.
- This project was randomly selected from a list of projects completed between January 1, 1999 and February 15, 2000.
- The project involved the lighting retrofits incorporated in the replacement of canopies over gas pump islands. High wattage metal halide lights were replaced with lower wattage metal halide light fixtures with some de-lamping. High wattage fluorescent lights were replaced with new technology light emitting diode (LED) strips.
- After some investigation, the LED strip lighting was found to be appropriately incentivized as a New Technology measure. It has been recommended that Energy Services attached

documentation to New Technology projects to explain the rationale used to determine New Technology status.

- A process error was uncovered as the LED canopy strip lighting was mistakenly entered into the project tracking database as "LED Exit Signs."

Study Detail

This project was initiated after an energy audit of the customer's facility. The energy audit was completed in September of 1998. The customer was in the process of replacing canopies over three gasoline and diesel pump islands and chose to install lower wattage metal halide fixtures. The manufacturer of the new fixtures claims several design improvements allow the use of a lower wattage lamps. The new fixture positions the metal halide lamp vertically rather than horizontally, and uses an improved reflector and prismatic lens to direct light out of the fixture in a uniform manner.

Lighting improvements were incentivized under the Trade Ally program in effect at the time. As the project neared completion, the Energy Services project lead separated the Light Emitting Diode strip lighting savings from the remainder of the project. This allowed the LED portion of the project to be incentivized as a New Technology.

After a review of the project file and discussion with the Energy Services project technical lead, it was determined that New Technologies incentives were appropriately applied toward the LED strip lighting as this was a relatively new product and this was the first application with Avista involvement. Initially the project file lacked documentation, which would explain the rationale behind assigning New Technology status to the LED strip lighting. This deficiency was brought to the attention of Energy Services and additional notes were added to the project file. Analysis staff recommended Energy Services incorporate such documentation with all New Technology projects. As a result, a policy change has been incorporated.

A review of the accounting transactions revealed an error in data entry. The LED canopy strip lighting was mistakenly entered into the Energy Services database as an LED exit sign project. The error caused incentive payments to be charged to the LED exit sign program account. Annual kWh savings were also erroneously credited to the LED exit sign program. Energy Services was informed of the error and appropriate account corrections were made.

A post-verification of the installation was performed by Energy Services and photographs of the equipment were included in the project file. The analysis team also performed an independent verification of this project. The engineering calculations were reviewed and found to be accurate.

Energy savings for this project totaled 12,800 kWh per year for the metal halide canopy lighting improvements and 8,340 kWh per year for the LED strip lighting. The customer received an incentive of $1,084.00.

Project Status:	Completed January of 1999
Program/Segment:	Site Specific Program
Technology:	Irrigation Pumping Efficiency Improvements
Site:	Farm
Location	Kahlotus, Washington

Study Summary

- This study resulted in no impact on energy savings estimates.

- This project was randomly selected from a list of projects completed between January 1, 1999 and February 15, 2000.
- The project involved the installation of a variable frequency drive on a irrigation pump motor and a retrofit from standard impact sprinkler heads to low pressure pivot rotator sprinkler heads. The project was completed under a performance-based agreement.
- Data was collected for over a year from water flow meters and Avista Utilities electric meters on irrigation pumps serving seven pivot irrigation systems. The results of the data collection analyses were used to establish energy and water savings, and the incentive amount.
- Several non-energy benefits were documented by the owners of the farm; including improved cold weather irrigation to provide a measure of frost protection, a large reduction in water usage, and reduced equipment failure caused by high water pressure stress.

Study Detail

In the summer of 1997, a study was begun at a family owned farm near Kahlotus, Washington. The farmers of this land were seeking assistance to reduce both electric power consumption and water usage.

The customer and the Energy Services technical lead chose to replace standard impact sprinkler heads with a low-pressure pivot rotator sprinkler heads. To allow proper operation and control of the new sprinklers, water pressure control was required. The pressure control was obtained by installing a variable frequency drive on a 100 horsepower pump serving the seven irrigated crop circles.

The sprinkler heads provided several benefits; including reduced water run off, greater uniformity in water application, reduced wind drift, and reduced water loss caused by evaporation. The new sprinkler heads also allowed the farmer to vary the water droplet size, allowing improved precision in water application.

The operators of the farm closely monitored water usage over several years. Electric usage history was available from Avista Utilities customer records. With this information, a performance-based energy efficiency agreement was executed. Avista and the farm operators collected water flow data and electric usage data for over one year following the installation of the low-pressure pivot rotator sprinkler heads and the variable frequency drive. The data collection was completed in December of 1998.

Several non-energy benefits were documented. Water savings totaled 554 acre-feet per year (180,521,454 gallons). Superior water distribution capabilities allowed the farm to provide a measure of frost protection. The customer anticipates significant maintenance cost savings from reduced equipment failure caused by high water pressure. The customer also expressed satisfaction with the improved water distribution on his crops, noting that "The crop under the rotator equipped center pivots was always in at least as good, or in better condition, than the crops grown under impact sprinkler equipped machines."

A review of the incentive formula in the energy efficiency agreement found that the incentive calculation was appropriately applied. A review of the accounting transactions found costs and incentives were appropriately charged to the Site Specific program.

The savings for this project totaled 51,326 kWh per year. The customer received an incentive of $2,566.00.

Project Status:	Completed May of 1999
Program/Segment:	Trade Ally and Site Specific Programs
Technology:	Cooling and Ventilation Improvements
Site:	Mine
Location:	Wallace, Idaho

<u>Study Summary</u>

- This study resulted in no impact on energy savings estimates.
- This project was randomly selected from a list of projects completed between January 1, 1999 and February 15, 2000.
- The project was completed using both the Trade Ally program and the Site Specific program. The Trade Ally portion allowed for expenditures to study and implement the replacement of *Whizbang* units with portable fans. The Site Specific program provided incentives for the conversion of an adjacent mineshaft into an exhaust shaft.
- The large scale and unique nature of these projects warrant an ongoing persistence study. The large annual energy savings could be reduced should the mine scale back its operations in the future.

<u>Study Detail</u>

Heat and humidity levels in the mineshafts are very high. The miners in the shafts developed a device called a *Whizbang* to provide cooling. A *Whizbang* is essentially a pipe, drilled with approximately a dozen 1/8" holes. The pipe is connected to a compressed air system and is turned on and off by the miners as needed. The study performed by Energy Services in coordination with the customer's own engineering staff indicated the mines had fifty *Whizbangs* operating up to 5,408 hours per year. While these devices worked well and were compatible with the extreme conditions found in the mines, they were created without regard to energy efficiency. Energy Services proposed replacing the *Whizbang* units with individual portable 2 horsepower cooling fans. The customer replaced the *Whizbangs*, on a limited basis, removing eighteen units and replacing them with two horsepower cooling fans.

The engineering estimates for the *Whizbang* replacements were reviewed and found to be appropriate. However, the customer is under no obligation to continue the use of the individual fans, nor does there appear to be a tracking mechanism in place to ensure that the air compressor loads are reduced. Analysis staff recommended Energy Services coordinate a follow-up study within the next six months to measure the persistence of this measure.

The ventilation project required that the mine open a connection to an adjacent shaft and use it for exhaust ventilation. By making the connection to the adjacent shaft, ventilation to the mine was increased and fan horsepower requirements were reduced.

Information included in the project file indicates a significant engineering effort was made to ensure this operational change would greatly improve the ventilation in the mine and reduce the required horsepower. Engineering calculations are detailed in an initial project memo from the Avista project engineer, however the project changed over time and subsequent calculations were absent in the project file. Final savings figures were presented only in a summary spreadsheet and to recreate the final energy savings figures was difficult.
Analysis staff recommended Energy Services review project files upon project completion and establish a procedure to ensure final energy savings calculations are clearly documented and reflect all changes between initial study and project completion.

As with the *Whizbang* project, any change in the mine's operation could dramatically alter the energy savings provided by the ventilation project. A follow-up study of both of these projects, by the analysis team in coordination with Energy Services, is to be initiated within the next six months.

The savings for the *Whizbang* cooling replacement project totaled 2,091,300 kWh per year and savings for the ventilation efficiency improvements totaled 1,942,100 kWh per year. The customer received an incentive (capped at 50% of the project cost) of $62,500.00.

Project Status:	Contracted as of March 31, 2000
Program/Segment:	Site Specific Program / Manufacturing Segment
Technology:	Process Fuel Conversion
Site:	Specialty Metals Manufacturer
Location	Spokane, Washington

<u>Study Summary</u>

- This study resulted in no impact on energy savings estimates.
- This project was randomly selected from a list of projects which were in progress as of March 31, 2000.
- This project was listed as Contracted as of March 31, 2000 and involves a process fuel switch. An electric oven is to be replaced with a natural gas oven.
- The project file contained a detailed engineering calculation to estimate potential electricity savings.
- A significant non-energy benefit was identified early in the study. The customer is nearing the maximum capacity of existing transformers. The process fuel switch will allow the customer to defer the installation of a new transformer and additional electrical circuit breakers and will free up approximately 40 kW of capacity to be used for future production expansion.
- The process requires precise temperature control and requires specialized ovens.

<u>Study Detail</u>

The manufacturing process, which is the subject of this project, involves the bonding of dissimilar metals. In this case, steel is bonded to aluminum using a molecular bonding material. The bond occurs as the steel and aluminum are heated in an oven with precise temperature control. The customer's process allows bonding to occur without reduction or oxidation, which often occur when dissimilar metals are in close proximity.

For this energy efficiency project, the customer will be replacing an existing radiant electric oven with a new radiant natural gas oven. The customer also needed to increase processing capacity and was considering several options including the installation of additional electric or gas fired ovens. The new gas oven chosen by the customer will provide this increase in the production capacity.

Energy Services personnel documented the operation of the existing electric oven and detailed the operation of up to two additional electric ovens under consideration to meet the increased process capacity. Using production information provided by the customer, it was calculated that the heating elements in the original oven consumed 166,400 kWh per year. Adding two similar

Table B3 **Allocation of Utility Costs Across Customer Segments and Technologies**

	Appliance	Assistive Tech	Controls	Motors	HVAC	Industrial	Lighting	Maintenance	Monitoring	New Tech	Regional	Renewable	Resource Mgmt	Shell	Sustainable building	Total $	% of portfolio
NEEA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 260,151	$ -	$ -	$ -	$ -	$ 260,151	14.4%
Agriculture	$ -	$ -	$ 3,526	$ 3,526	$ -	$ 3,526	$ -	$ -	$ 1,175	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,755	0.6%
Manufacturing	$ -	$ -	$ 35,833	$ 35,833	$ 35,833	$ 233,078	$ 28,845	$ 17,917	$ 35,833	$ 35,833	$ 35,833	$ -	$ -	$ -	$ -	$ 494,838	27.3%
Health Care	$ -	$ -	$ 6,081	$ 3,040	$ 9,121	$ 3,040	$ 12,383	$ 6,081	$ 3,040	$ 3,040	$ -	$ 3,040	$ 6,081	$ 3,040	$ -	$ 57,989	3.2%
Hospitality	$ 5,461	$ -	$ 16,383	$ 5,461	$ 5,461	$ -	$ 17,241	$ 5,461	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 55,468	3.1%
Office	$ -	$ -	$ 19,693	$ 9,846	$ 22,453	$ -	$ 41,821	$ 9,846	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 103,660	5.7%
Food Service	$ -	$ -	$ 42,027	$ -	$ -	$ -	$ 42,147	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 84,174	4.7%
Retail	$ -	$ -	$ 17,937	$ -	$ -	$ -	$ 43,893	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 61,830	3.4%
Residential	$ -	$ 19,791	$ -	$ -	$ 66	$ -	$ 1,520	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 21,377	1.2%
Limited Income (electric)	$ -	$ -	$ -	$ -	$ 296,485	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 23,870	$ 591	$ 320,946	17.7%
RMPP / Education	$ -	$ -	$ 55,241	$ -	$ 50,100	$ -	$ 198,413	$ -	$ -	$ 34,147	$ -	$ -	$ -	$ -	$ -	$ 337,901	18.7%
Total	$ 5,461	$ 19,791	$ 196,721	$ 57,707	$ 418,519	$ 239,645	$ 386,263	$ 39,305	$ 40,049	$ 73,020	$ 295,984	$ 3,040	$ 6,081	$ 26,910	$ 591	$ 1,810,088	100.0%
% of portfolio	0.3%	1.1%	10.9%	3.2%	23.2%	13.2%	21.3%	2.2%	2.2%	4.0%	16.4%	0.2%	0.3%	1.5%	0.0%	100.0%	

NOTE: This is a compilation of all utility costs, including incentives, by customer segment and technology.

REFERENCE: Comparable to *Table 3* of March 2000 Report.

Table B4

Allocation of Direct Incentives Across Customer Segments and Technologies

	Appliance	Assistive Tech	Controls	Motors	HVAC	Industrial	Lighting	Maintenance	Monitoring	New Tech	Regional	Renewable	Resource Mgmt	Shell	Sustainable building	Total $	% of portfolio
Regional	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,188)	$ -	$ -	$ -	$ -	$ (1,188)	-0.2%
Agriculture	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
Manufacturing	$ -	$ -	$ -	$ -	$ -	$ 179,328	$ 10,928	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 190,256	31.0%
Health Care	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,262	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,262	0.5%
Hospitality	$ -	$ -	$ -	$ -	$ -	$ -	$ 858	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 858	0.1%
Office	$ -	$ -	$ -	$ -	$ 2,760	$ -	$ 12,282	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 15,042	2.5%
Food Service	$ -	$ -	$ -	$ -	$ -	$ -	$ 120	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 120	0.0%
Retail	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,040	-$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,040	0.3%
Residential	$ -	$ 114	$ -	$ -	$ 66	$ -	$ 1,520	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,700	0.3%
Limited Income	$ -	$ -	$ -	$ -	$ 267,507	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 23,870	$ -	$ 291,377	47.5%
Education	$ -	$ -	$ 21,095	$ -	$ 15,953	$ -	$ 73,208	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 110,256	18.0%
TOTAL	$ -	$ 114	$ 21,095	$ -	$ 286,286	$ 179,328	$ 104,218	$ -	$ -	$ -	$ (1,188)	$ -	$ -	$ 23,870	$ -	$ 613,723	100.0%
% of portfolio	0.0%	0.0%	3.4%	0.0%	46.6%	29.2%	17.0%	0.0%	0.0%	0.0%	-0.2%	0.0%	0.0%	3.9%	0.0%	100.0%	

REFERENCE: Comparable to *Table 4* of March 2000 Report.

Table B4 — **Allocation of Direct Incentives Across Customer Segments and Technolog**

	Appliance	Assistive Tech	Controls	Motors	HVAC	Industrial	Lighting	Maintenance	Monitoring	New Tech	Regional	Renewable	Resource Mgmt	Shell	Sustainable building	Total $	% of portfoli
Regional	-	-	-	-	-	-	-	-	-	-	(1,188)	-	-	-	-	(1,188)	-0
Agriculture	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	C
Manufacturing	-	-	-	-	-	179,328	10,928	-	-	-	-	-	-	-	-	190,256	31
Health Care	-	-	-	-	-	-	3,262	-	-	-	-	-	-	-	-	3,262	C
Hospitality	-	-	-	-	-	-	858	-	-	-	-	-	-	-	-	858	C
Office	-	-	-	-	2,760	-	12,282	-	-	-	-	-	-	-	-	15,042	2
Food Service	-	-	-	-	-	-	120	-	-	-	-	-	-	-	-	120	0
Retail	-	-	-	-	-	-	2,040	-	-	-	-	-	-	-	-	2,040	0
Residential	-	114	-	-	66	-	1,520	-	-	-	-	-	-	-	-	1,700	0
Limited Income	-	-	-	-	267,507	-	-	-	-	-	-	-	-	23,870	-	291,377	47
Education	-	-	21,095	-	15,953	-	73,208	-	-	-	-	-	-	-	-	110,256	18
TOTAL	-	114	21,095	-	286,286	179,328	104,218	-	-	-	(1,188)	-	-	23,870	-	613,723	10C
% of portfolio	0.0%	0.0%	3.4%	0.0%	46.6%	29.2%	17.0%	0.0%	0.0%	0.0%	-0.2%	0.0%	0.0%	3.9%	0.0%	100.0%	

EFERENCE: Comparable to *Table 4* of March 2000 Report.

Table B5 — Allocation of Electric Savings Across Customer Segments and Technologies

	Appliance	Assistive Tech	Controls	Motors	HVAC	Industrial	Lighting	Maintenance	Monitoring	New Tech	Regional	Renewable	Resource Mgmt	Shell	Sustainable building	TOTAL	% of total
NEEA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0%
Agriculture	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0%
Manufacturing	-	-	561,150	6,841	-	889,907	220,054	-	-	-	-	-	-	-	-	1,677,952	11.8%
Health Care	-	-	-	-	1,842,789	-	181,923	-	-	-	-	-	-	-	-	2,024,712	14.3%
Hospitality	-	-	-	-	-	-	103,639	-	-	-	-	-	-	3,390	-	107,029	0.8%
Office	-	-	-	-	43,789	-	96,209	-	-	-	-	-	-	97,334	-	237,332	1.7%
Food Service	-	-	-	-	-	-	1,600	-	-	-	-	-	-	-	-	1,600	0.0%
Retail	-	-	-	-	-	-	44,053	-	-	-	-	-	-	-	-	44,053	0.3%
Residential	-	-	-	-	6,753,084	-	360,348	-	-	400	-	-	-	-	-	7,113,832	50.1%
Limited Income (electric)	-	-	-	-	1,108,040	-	-	-	-	-	-	-	-	44,324	-	1,152,364	8.1%
RMPP / Education	-	-	193,041	477,268	86,384	-	476,076	-	-	-	-	-	610,122	-	-	1,842,890	13.0%
TOTAL	-	-	754,191	484,109	9,834,086	889,907	1,483,902	-	-	400	-	-	610,122	145,048	-	14,201,764	
	0.0%	0.0%	5.3%	3.4%	69.2%	6.3%	10.4%	0.0%	0.0%	0.0%	0.0%	0.0%	4.3%	1.0%	0.0%		

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

REFERENCE: Comparable to *Table 5* of March 2000 Report.

Table B6 — Allocation of Therm Savings Across Customer Segments and Technologies

	Appliance	Assistive Tech	Controls	Motors	HVAC	Industrial	Lighting	Maintenance	Monitoring	New Tech	Regional	Renewable	Resource Mgmt	Shell	Sustainable building	TOTAL	% of total
NEEA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0%
Agriculture	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0%
Manufacturing	-	-	-	-	-	(4,829)	(22)	-	-	-	-	-	-	-	-	(4,851)	2.0%
Health Care	-	-	-	-	(43,214)	-	(2,418)	-	-	-	-	-	-	-	-	(45,632)	18.3%
Hospitality	-	-	-	-	-	-	(185)	-	-	-	-	-	-	-	-	(185)	0.1%
Office	-	-	-	-	1,111	-	(388)	-	-	-	-	-	-	61,582	-	62,324	-25.1%
Food Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0%
Retail	-	-	-	-	-	-	(12)	-	-	-	-	-	-	-	-	(12)	0.0%
Residential	-	-	-	-	(288,103)	-	-	-	-	-	-	-	-	-	-	(288,103)	115.8%
Limited Income (electric)	-	-	-	-	(18,779)	-	-	-	-	-	-	-	-	-	-	(18,779)	7.6%
RMPP / Education	-	-	28,893	-	-	-	(3,108)	-	-	-	-	-	22,726	-	-	48,513	-18.7%
TOTAL	-	-	28,893	-	(348,985)	(4,829)	(6,110)	-	-	-	-	-	22,726	61,582	-	(248,724)	
	0.0%	0.0%	-10.8%	0.0%	140.3%	1.9%	2.5%	0.0%	0.0%	0.0%	0.0%	0.0%	-9.1%	-24.8%	0.0%		

TE: These figures include de-rated therm savings from the Contracted and Construction phases.

FERENCE: Comparable to *Table 6* of March 2000 Report.

Table B7 **Cost-Effectiveness Statistics by Customer Segment**

	Total Resource Cost Test	Utility Cost Test	Participant Test	Non-Participant Test
NEEA	-	-	-	-
Agriculture	-	-		-
Manufacturing	1.05	0.86		0.40
Health Care	0.66	2.31	1.26	0.44
Hospitality	0.24	0.33	1.45	0.20
Office	2.27	2.52	10.85	0.63
Food Service	0.01	0.00		0.00
Retail	0.12	0.13	2.26	0.10
Residential	1.51	78.15	2.16	0.48
Limited Income (electric)	1.23	1.23		0.42
RMPP / Education	0.99	1.08	16.94	0.37
PORTFOLIO	1.04	1.84	2.98	0.43
PORTFOLIO w/o NEEA	**1.12**	**2.11**	**2.98**	**0.44**

REFERENCE: Comparable to *Table 9* of March 2000 Report.

Table B8 **Cost-Effectiveness Statistics by Technology**

	Total Resource Cost Test	Utility Cost Test	Participant Test	Non-Participant Test
Appliance	-	-		-
Assistive Tech	-	-		-
Controls	0.60	1.14	1.34	0.43
Motors	2.58	1.63		0.41
HVAC	1.18	4.63	2.12	0.47
Industrial	2.92	1.03		0.45
Lighting	0.72	0.64		0.28
Maintenance	-	-		-
Monitoring	-	-		-
New Tech	0.00	0.00		0.00
Regional	-	-	-	-
Renewable	-	-		-
Resource Mgmt	10.93	10.93		0.47
Shell	2.75	7.66	3.32	0.79
Sustainable Building	-	-		-
PORTFOLIO	1.04	1.84	2.98	0.43
PORTFOLIO w/o NEEA	**1.12**	**2.11**	**2.98**	**0.44**

REFERENCE: Comparable to *Table 10* of March 2000 Report.

Table B9 — Summary of Cost-Effectiveness Tests and Descriptive Statistics

Total Resource Cost Test		Regular Income portfolio without NEEA		Limited Income portfolio		Overall portfolio without NEEA
Electric avoided cost	$	4,303,697	$	457,790	$	4,761,487
Non-Energy benefits	$	76,850	$	-	$	76,850
Natural Gas avoided cost	$	(859,424)	$	(63,443)	$	(922,867)
TRC benefits	$	3,521,122	$	394,347	$	3,915,469
Implementation cost	$	905,457	$	29,569	$	935,026
Customer cost	$	2,273,339	$	291,377	$	2,564,716
TRC costs	$	3,178,795	$	320,946	$	3,499,742
TRC ratio		1.11		1.23		1.12

Utility Cost Test		Regular Income portfolio without NEEA		Limited Income portfolio		Overall portfolio without NEEA
Electric avoided cost	$	4,303,697	$	457,790	$	4,761,487
Natural Gas avoided cost	$	(859,424)	$	(63,443)	$	(922,867)
UCT benefits	$	3,444,273	$	394,347	$	3,838,620
Implementation cost	$	905,457	$	29,569	$	935,026
Incentive cost	$	595,293	$	291,377	$	886,670
UCT costs	$	1,500,749	$	320,946	$	1,821,696
UCT ratio		2.30		1.23		2.11

Participant Test		Regular Income portfolio without NEEA		Limited Income portfolio		Overall portfolio without NEEA
Bill Reduction	$	4,471,020	$	456,505	$	4,927,525
Non-Energy benefits	$	76,850	$	-	$	76,850
Participant benefits	$	4,547,869	$	456,505	$	5,004,374
Customer project cost	$	2,273,339	$	291,377	$	2,564,716
Incentive received	$	(595,293)	$	(291,377)	$	(886,670)
Participant costs	$	1,678,046	$	-	$	1,678,046
Participant Test ratio		2.71	NA			2.98

Non-Participant Test		Regular Income portfolio without NEEA		Limited Income portfolio		Overall portfolio without NEEA
Avoided cost savings	$	3,444,273	$	394,347	$	3,838,620
Non-Part benefits	$	3,444,273	$	394,347	$	3,838,620
Revenue loss	$	6,274,491	$	619,887	$	6,894,378
Implementation	$	905,457	$	29,569	$	935,026
Customer incentives	$	595,293	$	291,377	$	886,670
Non-Part costs	$	7,775,240	$	940,833	$	8,716,073
Non-Part. ratio		0.44		0.42		0.44

Descriptive Statistics		Regular Income portfolio without NEEA		Limited Income portfolio		Overall portfolio without NEEA
Annual kWhs		13,049,400		1,152,364		14,201,764
Cust cost/kWh	$	0.174	$	0.253	$	0.181
Impl cost/kWh	$	0.069	$	0.026	$	0.066
El AC $/kWh	$	0.330	$	0.397	$	0.335
Inc cost/kWh	$	0.046	$	0.253	$	0.062

REFERENCE: Comparable to *Table 13* of March 2000 Report.

Table B10

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	Idaho DSM Expenditures	Idaho DSM Revenues	Idaho Beginning DSM balance	Idaho Ending DSM balance	Idaho Interest *	Idaho Ending bal. with Interest
January 1999	$ 171,037	$ 371,658	$ 2,627,965	$ 2,828,586	$ 10,950	$ 2,839,535	$ 70,147	$ 161,905	$ 1,053,579	$ 1,145,337	$ 2,385	$ 1,147,722
February	$ 188,863	$ 321,493	$ 2,839,535	$ 2,972,165	$ 21,756	$ 2,993,921	$ 100,620	$ 157,171	$ 1,147,722	$ 1,204,273	$ 8,767	$ 1,213,040
March	$ 416,803	$ 292,771	$ 2,993,921	$ 2,869,889	$ 23,172	$ 2,893,061	$ 57,166	$ 143,563	$ 1,213,040	$ 1,299,438	$ 9,378	$ 1,308,815
April	$ 781,855	$ 266,608	$ 2,893,061	$ 2,377,811	$ 23,379	$ 2,401,191	$ 268,935	$ 132,749	$ 1,308,815	$ 1,172,629	$ 10,017	$ 1,182,647
May	$ 333,268	$ 247,454	$ 2,401,191	$ 2,315,377	$ 21,015	$ 2,336,392	$ 131,689	$ 121,686	$ 1,182,647	$ 1,172,644	$ 9,894	$ 1,182,538
June	$ 283,079	$ 266,981	$ 2,336,392	$ 2,320,294	$ 18,805	$ 2,339,099	$ 87,749	$ 121,986	$ 1,182,538	$ 1,216,775	$ 9,391	$ 1,226,165
July	$ 315,854	$ 237,115	$ 2,339,099	$ 2,260,360	$ 18,567	$ 2,278,927	$ 82,662	$ 121,018	$ 1,226,165	$ 1,264,521	$ 9,566	$ 1,274,087
August	$ 470,627	$ 272,035	$ 2,278,927	$ 2,080,335	$ 18,338	$ 2,098,673	$ 146,099	$ 82,983	$ 1,274,087	$ 1,210,971	$ 9,931	$ 1,220,902
September	$ 220,534	$ 302,045	$ 2,098,673	$ 2,180,184	$ 17,381	$ 2,197,565	$ 85,885	$ 86,004	$ 1,220,902	$ 1,221,021	$ 9,908	$ 1,230,929
October	$ 333,763	$ 260,080	$ 2,197,565	$ 2,123,882	$ 17,060	$ 2,140,942	$ 304,545	$ 81,571	$ 1,230,929	$ 1,007,955	$ 9,736	$ 1,017,691
November	$ 174,943	$ 263,916	$ 2,140,942	$ 2,229,915	$ 17,230	$ 2,247,145	$ 167,877	$ 85,391	$ 1,017,691	$ 935,206	$ 8,927	$ 944,132
December	$ 588,013	$ 317,111	$ 2,247,145	$ 1,976,243	$ 17,427	$ 1,993,670	$ 232,356	$ 102,257	$ 944,132	$ 814,034	$ 7,786	$ 821,820
January 2000	$ 211,344	$ 350,395	$ 1,993,670	$ 2,132,721	$ 16,839	$ 2,149,560	$ 143,926	$ 93,727	$ 821,820	$ 771,621	$ 7,010	$ 778,631
1999 totals	$ 4,278,640	$ 3,419,265			$ 225,080		$ 1,735,728	$ 1,398,284			$ 105,685	
2000 totals	$ 211,344	$ 350,395			$ 16,839		$ 143,926	$ 93,727			$ 7,010	

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	$ 3,681,544	$ 3,973,922	$ 13,335	$ 3,987,257
February	$ 289,483	$ 478,664	$ 3,987,257	$ 4,176,438	$ 30,523	$ 4,206,961
March	$ 473,969	$ 436,334	$ 4,206,961	$ 4,169,326	$ 32,549	$ 4,201,876
April	$ 1,050,790	$ 399,355	$ 4,201,876	$ 3,550,440	$ 33,397	$ 3,583,837
May	$ 464,956	$ 369,140	$ 3,583,837	$ 3,488,021	$ 30,909	$ 3,518,930
June	$ 370,828	$ 388,967	$ 3,518,930	$ 3,537,069	$ 28,196	$ 3,565,265
July	$ 398,516	$ 358,133	$ 3,565,265	$ 3,524,881	$ 28,133	$ 3,553,014
August	$ 616,726	$ 355,018	$ 3,553,014	$ 3,291,306	$ 28,269	$ 3,319,575
September	$ 306,419	$ 388,049	$ 3,319,575	$ 3,401,205	$ 27,289	$ 3,428,494
October	$ 638,308	$ 341,651	$ 3,428,494	$ 3,131,837	$ 26,796	$ 3,158,634
November	$ 342,820	$ 349,307	$ 3,158,634	$ 3,165,121	$ 26,157	$ 3,191,277
December	$ 820,369	$ 419,368	$ 3,191,277	$ 2,790,277	$ 25,213	$ 2,815,490
January 2000	$ 355,270	$ 444,122	$ 2,815,490	$ 2,904,342	$ 23,849	$ 2,928,191
1999 totals	$ 6,014,368	$ 4,817,549			$ 330,765	
2000 totals	$ 355,270	$ 444,122			$ 23,849	

REFERENCE: Comparable to *Table 14* of March 2000 Report.

Appendix D

Exhibit D – Annual Load and Resource Forecast

		AVISTA CORP.																			
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	248	0	249	0	246	0	247	0	251	0	255	0	259	0	264	0	270	0	275	0
18	TOTAL REQUIREMENTS	2871	1682	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

Appendix E

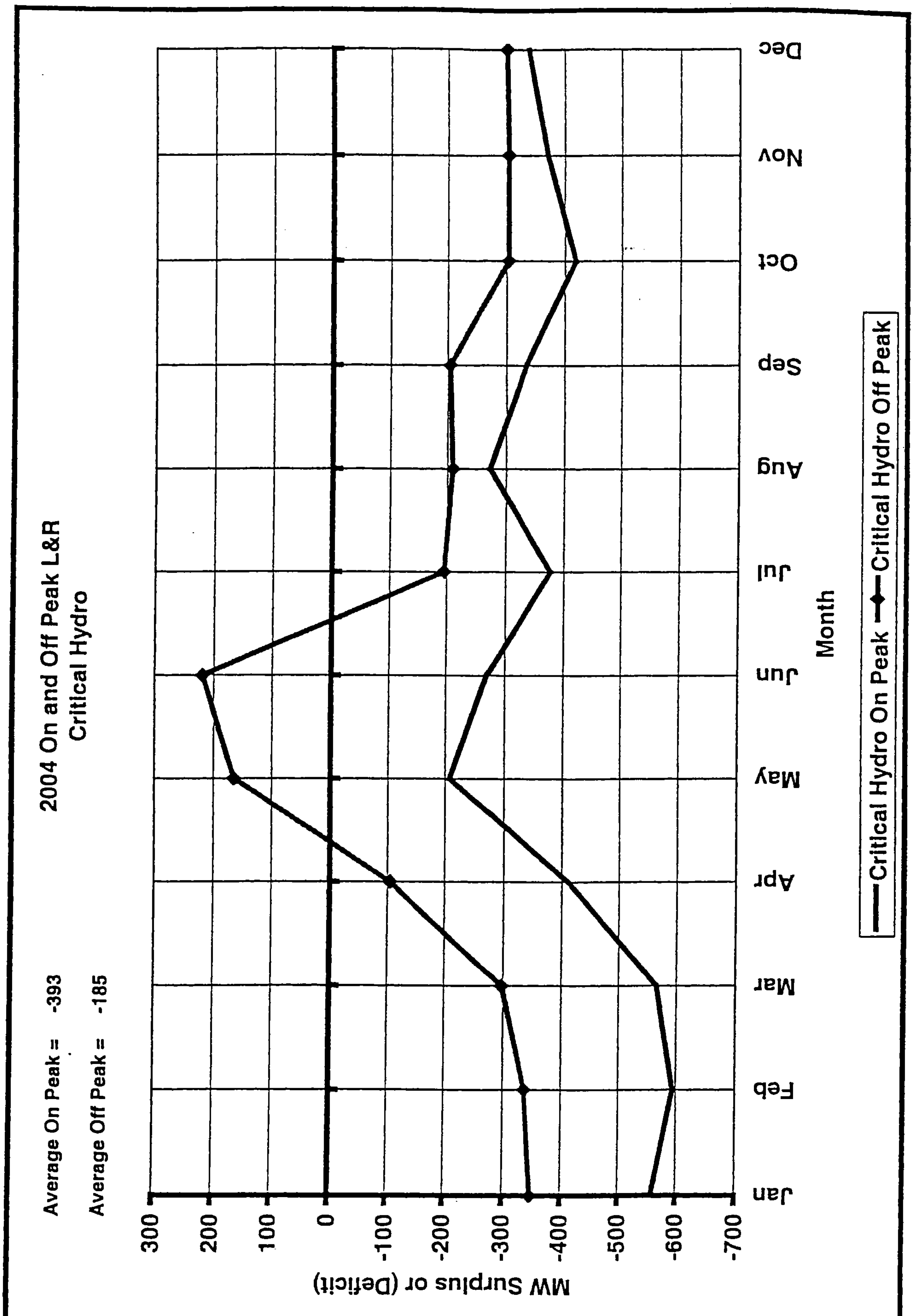
Avista Utilities

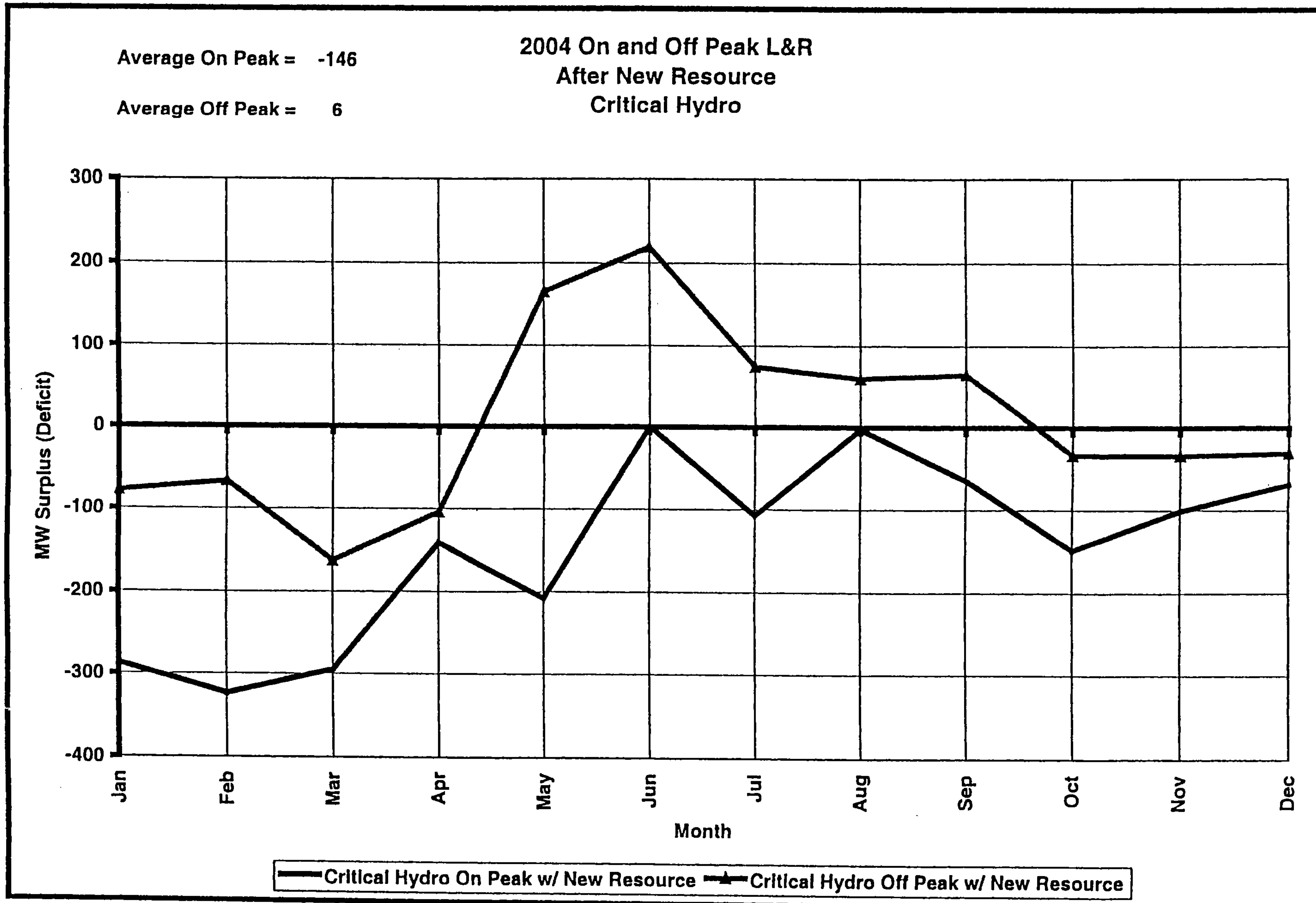
System Physical Surplus/(Deficiency)

2004

Critical Hydro Conditions

Month & Hours	Net System Load	PacifiCorp Exchange	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	-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


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


Average On Peak = -146
Average Off Peak = 6
2004 On and Off Peak L&R
After New Resource
Critical Hydro
MW Surplus (Deficit)
300
200
100
0
-100
-200
-300
-400
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

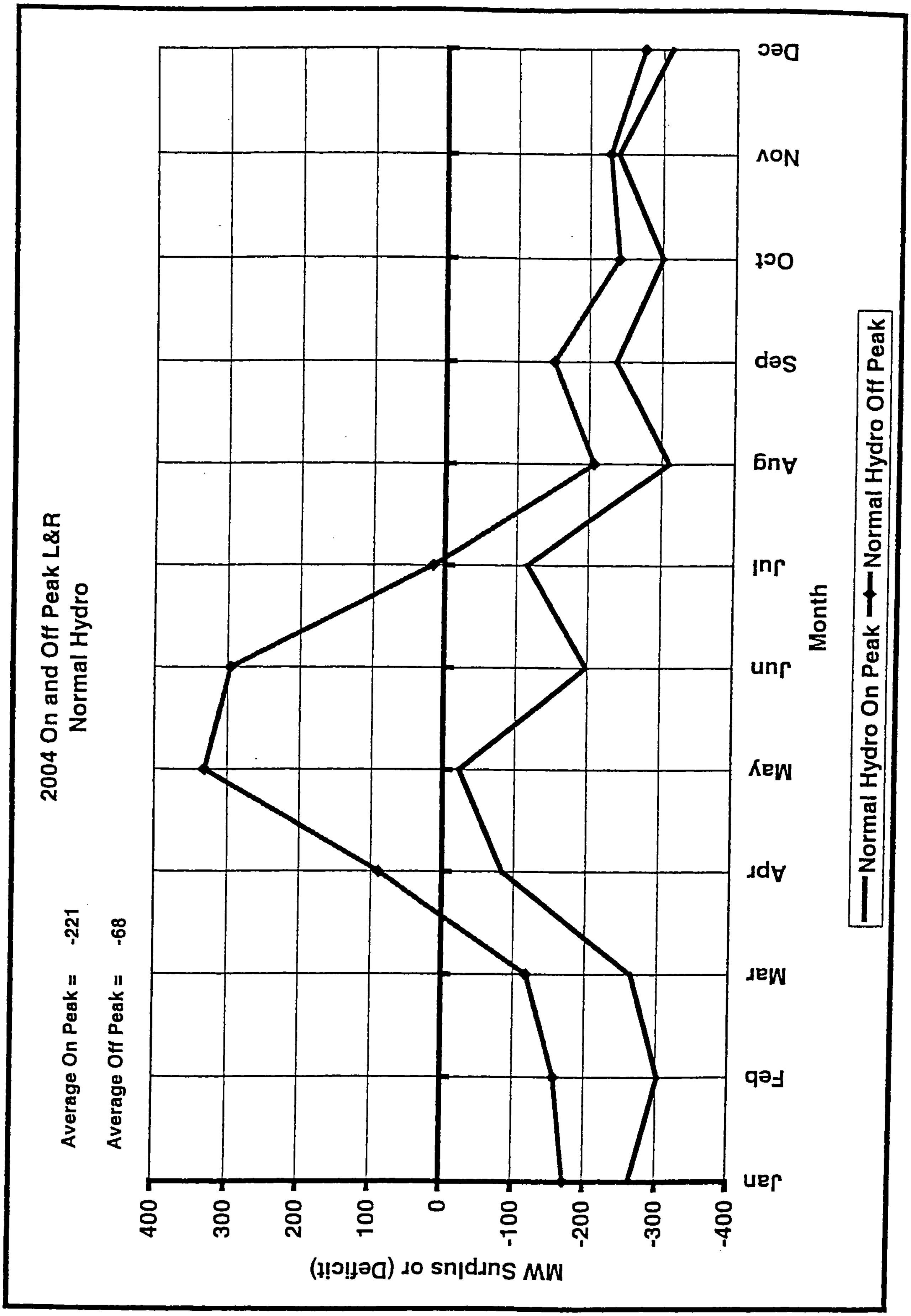
Avista Utilities

System Physical Surplus/(Deficiency)

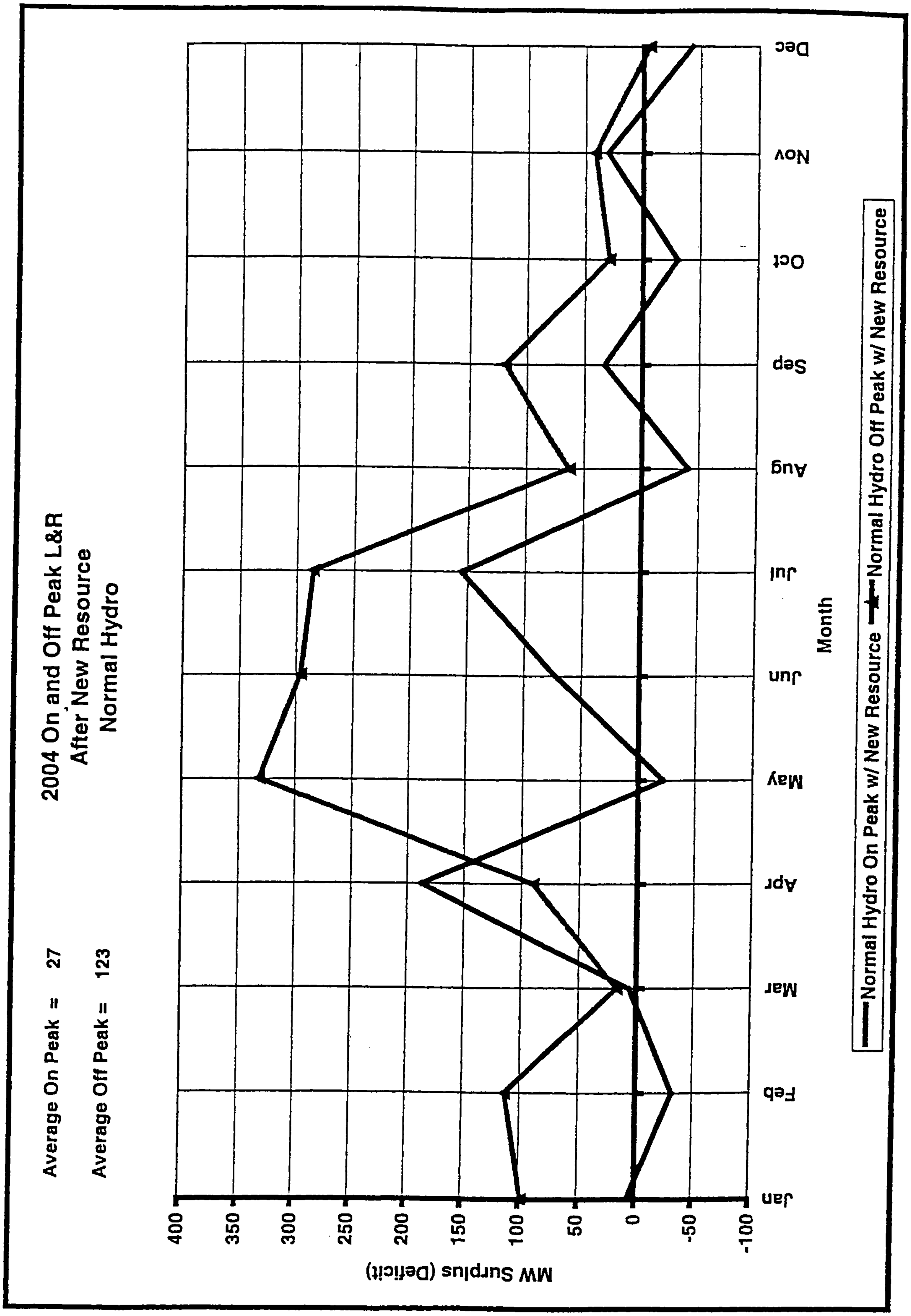
2004

Normal Hydro Conditions

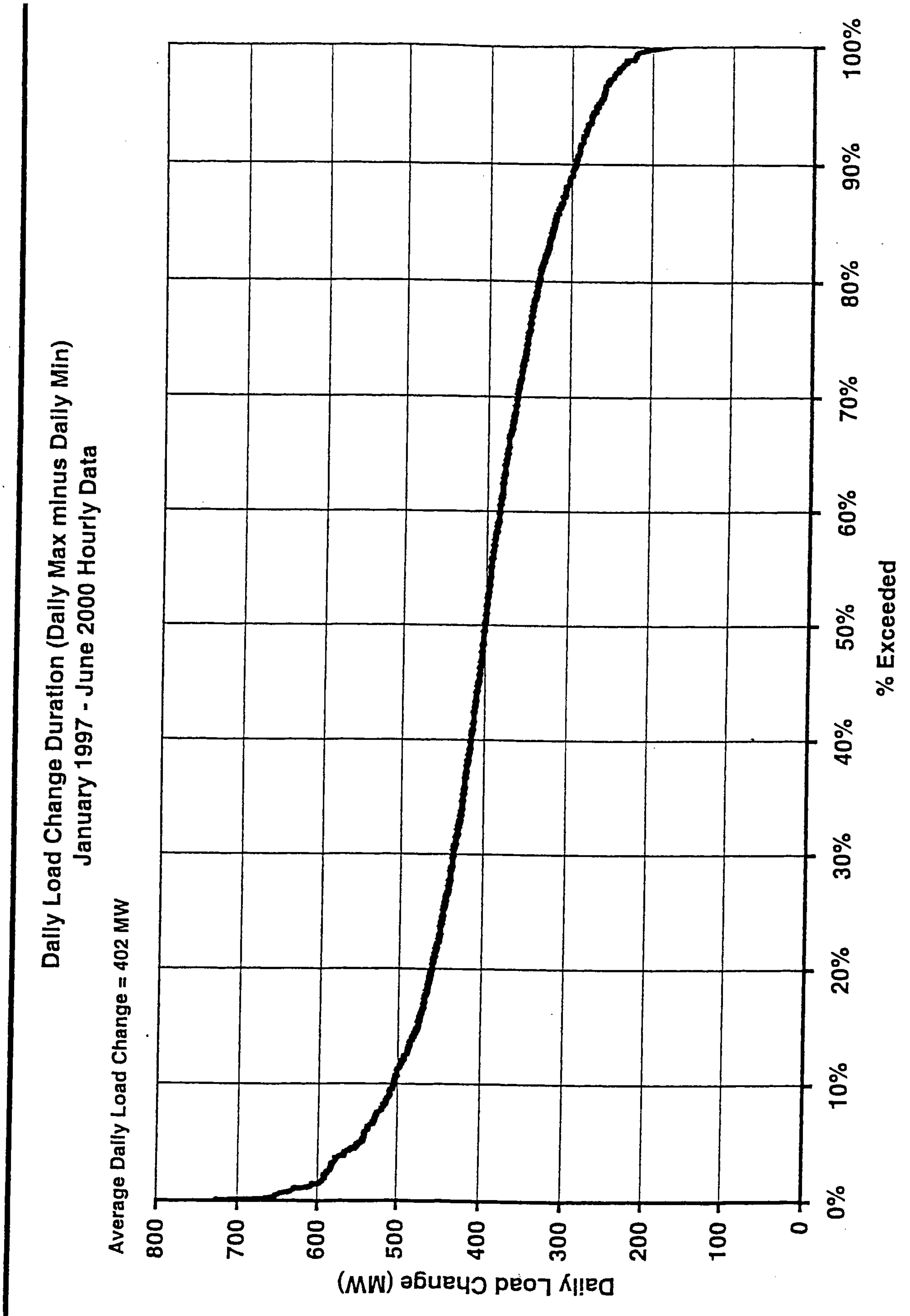
Month & Hours	Net System Load	PacifiCorp Exchange	Contract Resources: Spokane Upriver	Contract Resources: Small Power	Contract Resources: BPA Subscrip	Contract Resources: BPA WNP #3	Contract Requirements: Can Ent Rtn	Contract Requirements: PGE #1	Contract Requirements: SnoPud	Cogen.	Colstrip	Kettle Falls	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


2004 On and Off Peak L&R
Normal Hydro
Average On Peak = -221
Average Off Peak = -68
MW Surplus or (Deficit)
400
300
200
100
0
-100
-200
-300
-400
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Month
Normal Hydro On Peak
Normal Hydro Off Peak

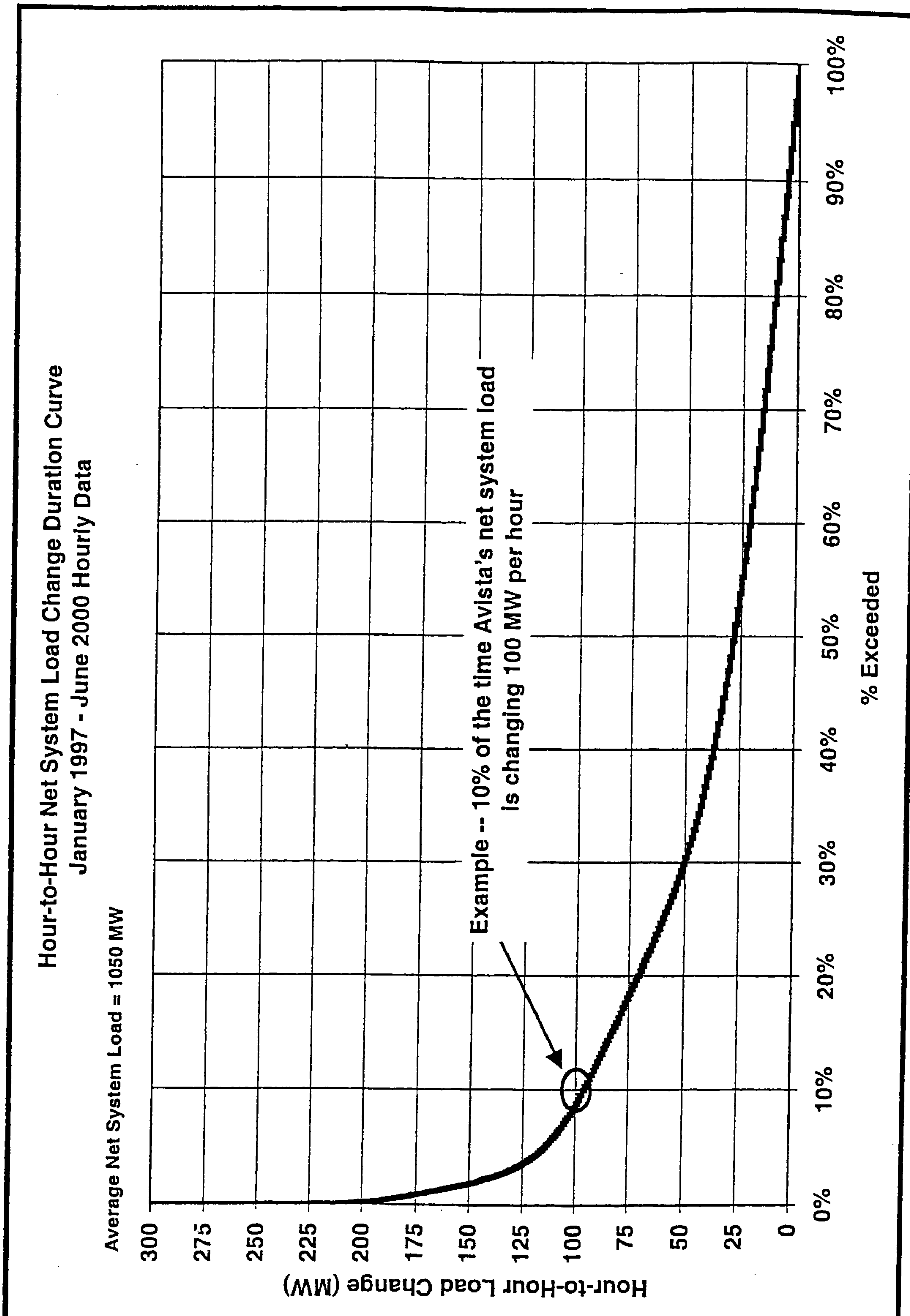
6

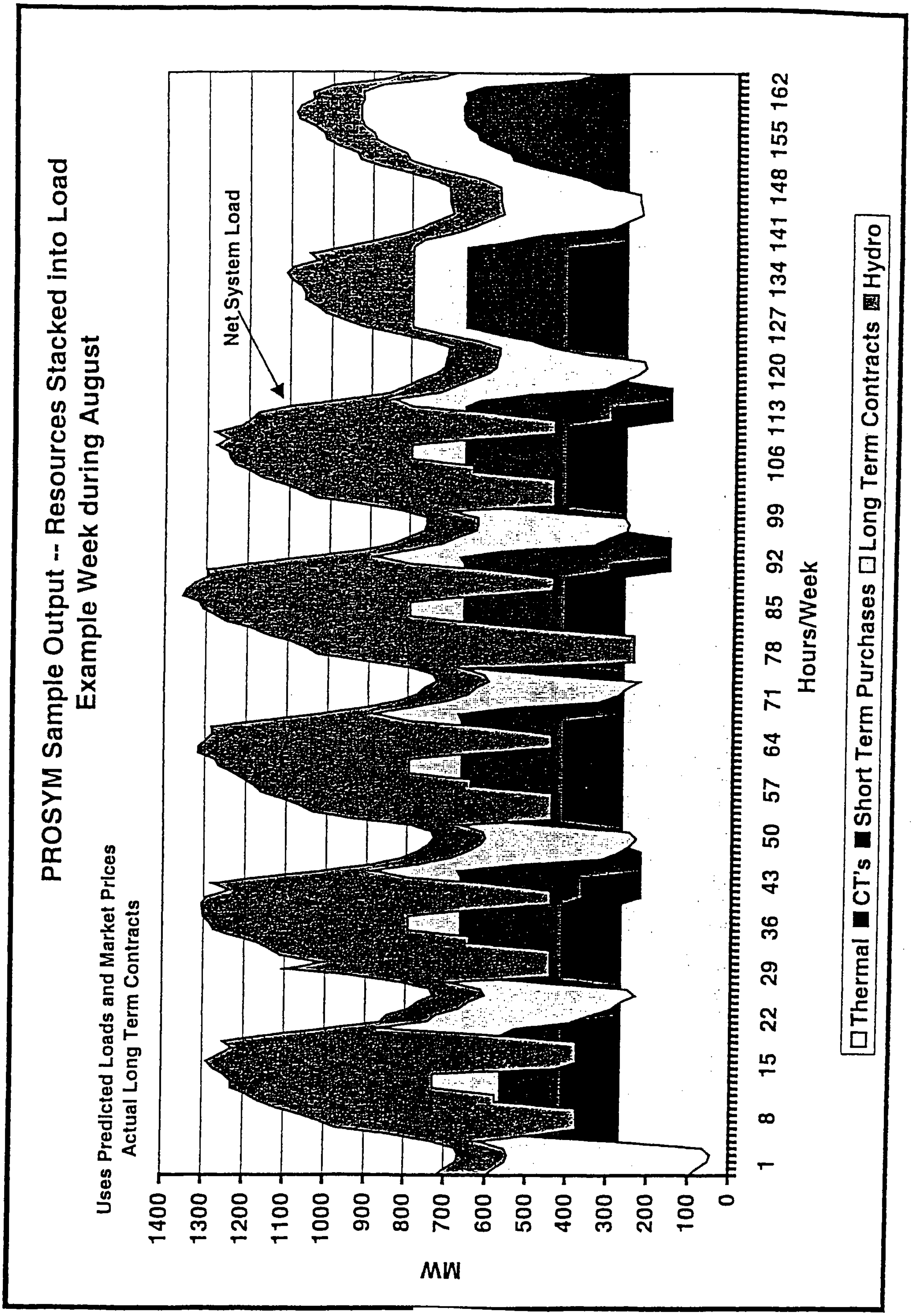


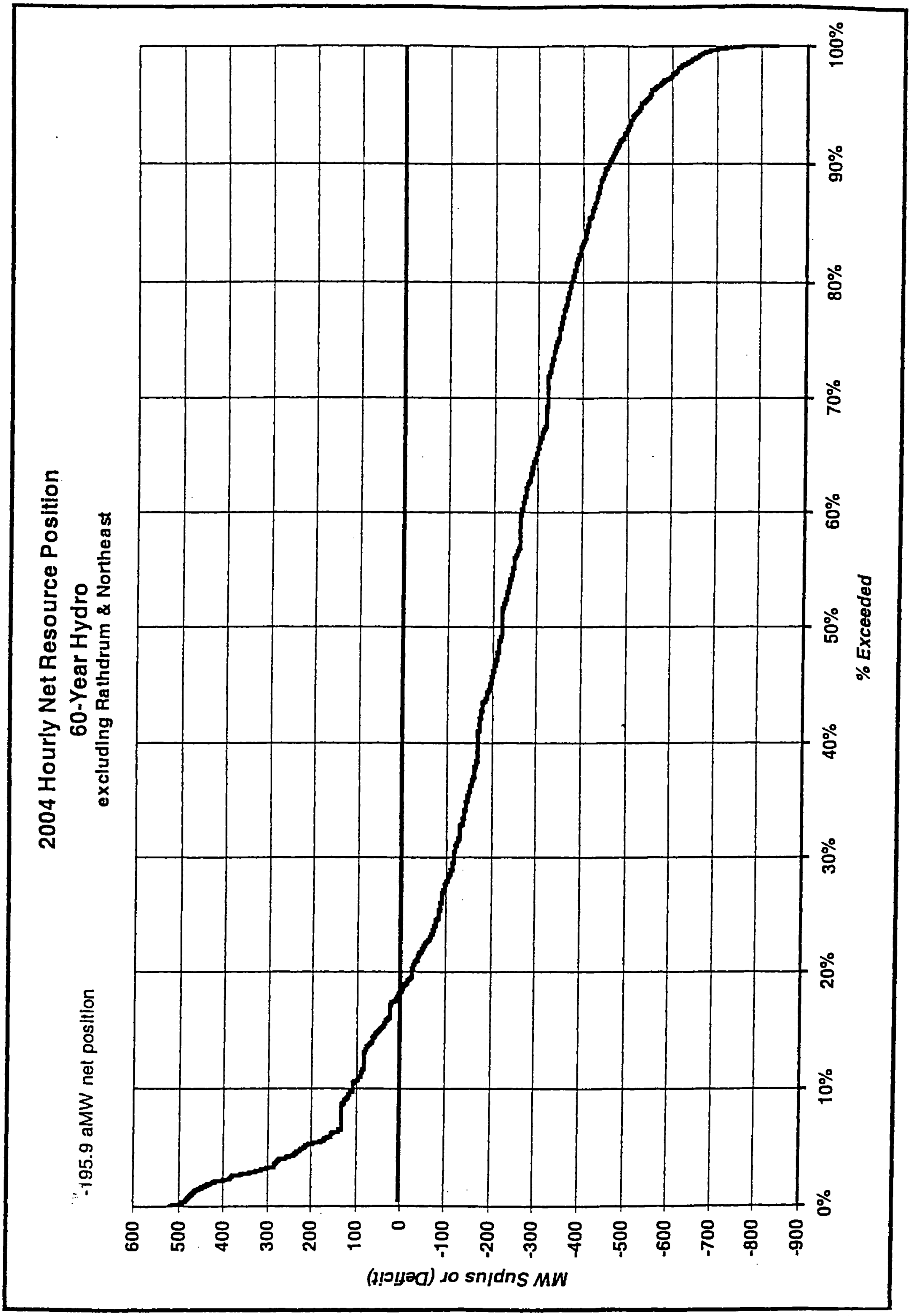
2004 On and Off Peak L&R
After New Resource
Normal Hydro
Average On Peak = 27
Average Off Peak = 123
MW Surplus (Deficit)
400
350
300
250
200
150
100
50
0
-50
-100
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Month
Normal Hydro On Peak w/ New Resource
Normal Hydro Off Peak w/ New Resource

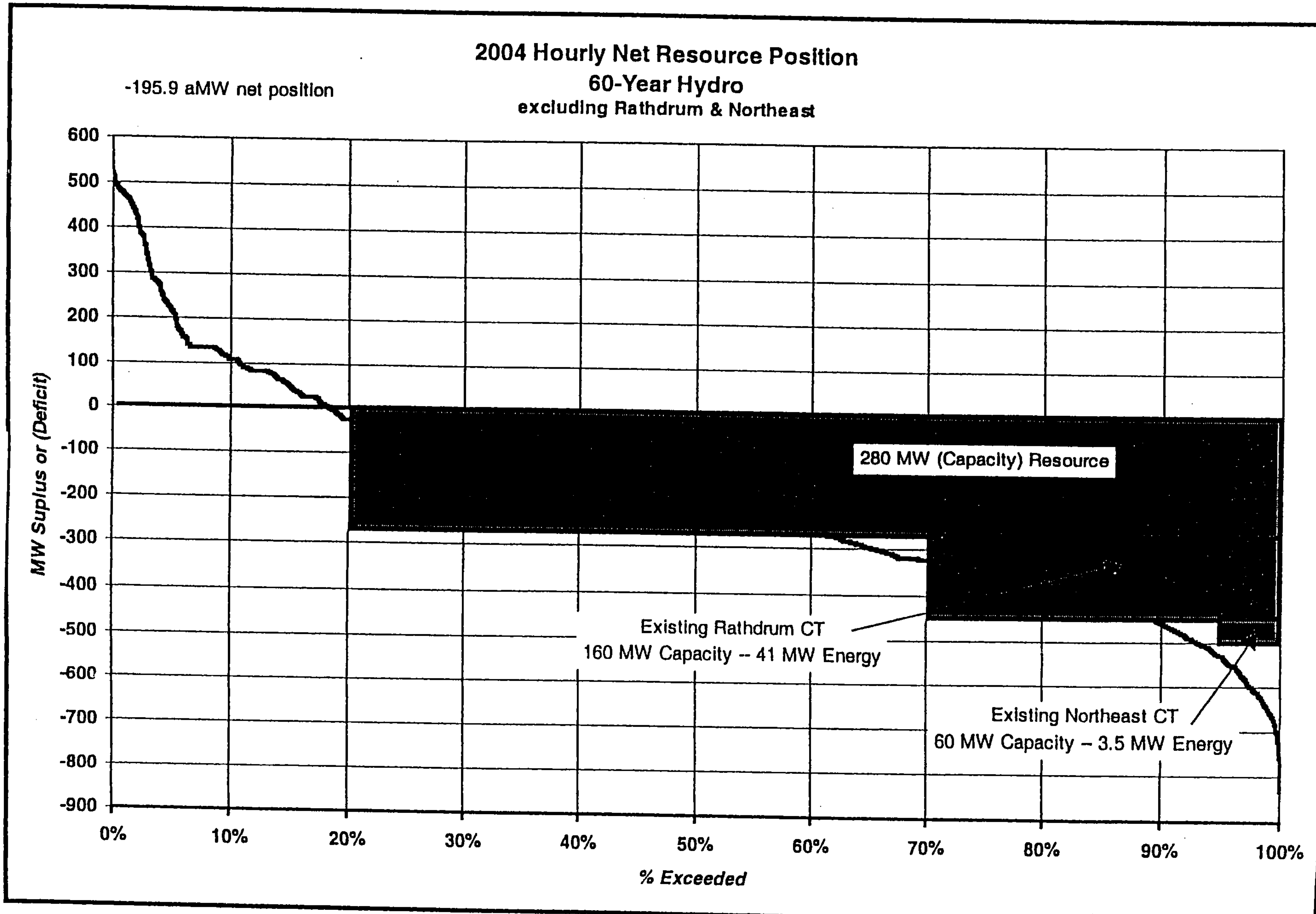


Daily Load Change Duration (Daily Max minus Daily Min)
January 1997 - June 2000 Hourly Data
Average Daily Load Change = 402 MW
Daily Load Change (MW)
800
700
600
500
400
300
200
100
0
% Exceeded
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%


Hour-to-Hour Net System Load Change Duration Curve
January 1997 - June 2000 Hourly Data
Average Net System Load = 1050 MW
Example -- 10% of the time Avista's net system load
Is changing 100 MW per hour
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


PROSYM Sample Output -- Resources Stacked into Load
Example Week during August
Uses Predicted Loads and Market Prices
Actual Long Term Contracts
Net System Load
MW
1400
1300
1200
1100
1000
900
800
700
600
500
400
300
200
100
0
1 8 15 22 29 36 43 50 57 64 71 78 85 92 99 106 113 120 127 134 141 148 155 162
Hours/Week
Thermal
CT's
Short Term Purchases
Long Term Contracts
Hydro


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



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

MODEL CONTRACTS

(not included)