BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-01__________

DIRECT TESTIMONY OF KELLY O. NORWOOD

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

Q. Please state your name, employer and business address.

A. My name is Kelly O. Norwood. I am employed as the Vice President and General Manager of Energy Resources by Avista Corporation at 1411 East Mission Avenue, Spokane, Washington.

Q. Please briefly describe your educational background and professional experience.

A. I am a graduate of Eastern Washington University with a Bachelor of Arts Degree in Business Administration, majoring in Accounting. I joined the Company in June 1981. Over the past 20 years I have spent approximately nine years in the Rates Department with involvement in cost of service, rate design and revenue requirements. I have spent approximately eleven years in the Energy Resources Department (power supply and natural gas supply) in a variety of roles with involvement in resource planning, system operations, resource analysis, negotiation of power contracts, and risk management. I was appointed to my present position in August 2000.

Q. What is the scope of your testimony in this proceeding?

A. My testimony will explain Avista's request for deferred accounting on a temporary basis for the period January 1, 2002 through the conclusion of the general rate case, to allow the Company the opportunity for recovery of the additional power supply related costs during this period. I will also explain Avista's request for a power cost adjustment mechanism to be implemented at the conclusion of this general rate case. Finally, my testimony will explain why the Company believes that the 1929-1988 60-year streamflow record should be used to normalize power costs for ratemaking purposes, instead of the 1949-1988 40-year period resulting from the use of the 40-year rolling average methodology that was approved in the last rate case.

I am sponsoring Exhibit Nos. _____ (KON-1) through _____ (KON-3) for identification, which were prepared under my direction.

A table of the contents for my testimony is as follows:

II. SUMMARY

Q. Please briefly summarize your testimony.

A. **Temporary Deferred Accounting**

The Company currently has accounting treatment in place, approved by the Commission, that allows Avista to defer, or set aside, certain power supply related costs through December 31, 2001 for the opportunity for later recovery. Current projections show that the Company will incur approximately $19.5 million (Washington jurisdictional share) of additional power supply related costs from January through October 2002, over and above the annual level of costs that are currently being collected from customers in base retail rates.

A gap currently exists between the termination of the current deferred account mechanism on December 31, 2001, and the conclusion of the current general rate case, which may occur as late as October 31, 2002. Without some form of accounting treatment authorized by the Commission, the additional costs during this period would be absorbed by the Company and would further exacerbate the current weak financial condition of the Company.

Historically, the Commission has authorized deferred accounting treatment which allows the utility the opportunity for recovery of additional costs that are incurred either in between general rate cases or during the pendency of the general rate case. The Company is requesting that the Commission issue an order that would bridge this gap, and allow Avista to defer the additional costs for the period January 1, 2002 until the conclusion of the general rate case. This would provide the Company with the opportunity for recovery of these costs. Coincident with the filing of this docket, the Company has filed an accounting petition seeking authorization of this temporary deferred accounting.

Power Cost Adjustment Mechanism

Through this filing the Company is requesting that the Commission authorize a power cost adjustment mechanism to become effective at the conclusion of the general rate case. The financial impact of the variation of power costs experienced by the Company from year to year would be "smoothed-out" through the PCA, which would add stability to the financial results of the Company. The variability in power costs is driven primarily, either directly or indirectly, by changes in hydroelectric generation conditions, wholesale electric market prices, and wholesale natural gas market prices, all of which are highly variable, unpredictable and beyond the Company's control. The Company is proposing to include 90% of the changes in these costs in the PCA, to reflect a sharing of costs between customers and shareholders.

The added financial stability provided by the proposed PCA would result in a lower cost of capital to the Company over time, which would be flowed through to customers in the form of lower retail rates. In this filing the Company has proposed a reduction in the requested return on equity of 50 basis points associated with the proposed implementation of the PCA, which would be an immediate direct benefit to customers.

In developing its proposal, the Company focused its efforts on a mechanism that would be simple to understand, simple to implement, provides benefits to all stakeholders, and that complies with the previous criteria outlined by the Commission regarding PCA mechanisms.

60-Year vs 40-Year Water Record

A careful review of the evidence will show that the previously adopted 40-year rolling average methodology will not provide the best estimate of average water conditions for ratemaking purposes. The use of the water record for the 40-year period 1949-1988, based on the 40-year rolling average methodology, would decrease the Company's power costs by approximately $4.6 million per year on a Washington jurisdictional basis. Such an adjustment would be based on the inappropriate use of more favorable streamflow conditions for normalization purposes than can be justified with the available data.

Other parties in the region such as the Northwest Power Pool and the Northwest Power Planning Council use the full 60 years of data available from 1929-1988. The Company is not aware of any regional studies that use the rolling average methodology, or the 1949-1988 40-year period. The 1929-1988 60-year record should be used in this case for ratemaking purposes as proposed by the Company.

III. TEMPORARY DEFERRED ACCOUNTING

Q. Please explain the Company's request for the authorization of temporary deferred accounting.

A. As stated earlier, the Company currently has accounting treatment in place, approved by the Commission, that allows Avista to defer, or set aside, certain power supply related costs through December 31, 2001 for the opportunity for later recovery. The specific costs deferred are power supply related costs that are being incurred by the Company each month, that are not being recovered by the Company through existing retail rates. The current deferred accounting treatment ends on December 31, 2001.

The traditional general rate case process by itself does not provide the Company the opportunity for recovery of costs that are incurred either in between general rate cases or during the pendency of the general rate case. A general rate case in Washington normally takes approximately eleven months to process, and rates are adjusted at the end of the eleven-month period. In addition, the rates set at the conclusion of the rate case are generally set to recover costs under "normal" conditions on a going-forward basis. Therefore, the general rate making process by itself does not provide the Company with the opportunity for timely recovery of certain costs. Historically, the Commission has authorized deferred accounting treatment which allows the utility the opportunity for recovery of additional costs that are incurred between general rate cases or during the rate case.

As Mr. Johnson explains in his testimony, current projections show that the Company will incur approximately $19.5 million (Washington jurisdictional share) of additional power supply related costs in the January through October 2002 period, over and above the level of costs that are currently being collected from customers in base retail rates. The general rate case should be concluded by October 31, 2002, and in its general rate case filing, the Company has proposed ratemaking treatment of the costs the Company will incur subsequent to the conclusion of the general rate case.

A gap currently exists between the termination of the current deferred accounting mechanism on December 31, 2001, and the conclusion of the general rate case, which for discussion purposes in my testimony, I will assume to be October 31, 2002. Without some form of accounting treatment authorized by the Commission, the additional costs during this period would be absorbed by the Company and would further exacerbate the current weak financial condition of the Company, as explained by Mr. Eliassen.

The Company is requesting that the Commission issue an order that would bridge this gap, and allow Avista to defer the additional costs for the period January 1, 2002 through October 31, 2002, while the general rate case is pending. This would provide the Company with the opportunity for recovery of those deferred costs.

Q. Did the Commission's Sixth Supplemental Order in Docket No. UE-010395, dated September 24, 2001, preclude the Company in any way from requesting deferred accounting treatment for these increased costs for the period January through October 2002?

A. No. Although that Order terminated the existing deferred accounting mechanism on December 31, 2001, it did not preclude a request by the Company for deferred accounting in some form beginning in January 2002. The Commission's Order recognized that the Company would be filing a general rate case by December 1, 2001, and in fact required the Company to do so. In Paragraph 86 of the Order, the Commission stated as follows:

> We can consider as part of the general rate case whether, and by what means, Avista may be permitted to recover the fourth quarter 2001 deferral amounts and power costs it may subsequently incur. (emphasis added)

Q. In the recent surcharge proceeding in Docket No. UE-010395 there was discussion regarding power cost adjustment (PCA) mechanisms, deferral mechanisms, and "side accounts." Would you please briefly explain the difference between the three, and specify the accounting treatment being requested by the Company?

A. Yes. The table below includes a brief description of a power cost adjustment mechanism, deferred accounting and a "side account."

Power Cost Adjustment	1) Based on Commission order 2) Accounting process determined 3) Rate change process determined 4) Affects regulatory and financial accounting 5) Inclusion in rates subject to a review in a future proceeding
Deferred Accounting	1) Based on Commission order 2) Accounting process determined 3) **Rate change process <u>not</u> determined** 4) Affects regulatory and financial accounting 5) **Inclusion in rates subject to detailed hearings in a future proceeding**
"Side Account"	1) **<u>No</u> Commission order required** 2) **<u>No</u> formal accounting process** 3) **<u>No</u> rate change process determined** 4) **<u>No</u> specific regulatory or financial accounting** 5) **May or may not affect rates**

<u>Power Cost Adjustment</u>

As can be seen in the table above, a PCA is implemented through a Commission order. The order would establish the accounting process, including the specific FERC Accounts to be used to record accounting entries. The order would also determine the process to change rates on a periodic basis to flow through to customers rebates or surcharges. Rate changes (increases or decreases) could occur, for example, on an annual basis, or when the balance in the PCA account reaches a certain level and triggers a rate adjustment.

Under a PCA, the changes in costs to the Company would be set aside each month for both regulatory and financial reporting purposes. For example, if the Company incurs increased power costs in a month, the PCA accounting entry would offset the increased costs by recording, essentially, an accounts receivable entry from customers on the Company's balance sheet, and a corresponding reduction in power expenses on the income statement. The effect of these entries is to set aside the increased costs for later recovery, and the increased costs would not affect the earnings of the Company for that month. In a similar manner, when there is a reduction in power costs in a month, the dollar amount is set aside for later rebate to customers, and the reduction in costs does not result in an improvement in earnings to the Company for that month for either regulatory or financial reporting purposes.

With regard to the review of the reasonableness of the dollars to be rebated or surcharged to customers, the review process under a PCA would tend to be more streamlined, as compared to the determination of the reasonableness of costs in a general rate case, for a couple of reasons. First, the PCA would deal with a specific set of costs that are determined to be appropriate to be included in the PCA, similar to that of the Purchased Gas Adjustment (PGA) mechanism where some revenue and expense categories are included in the PGA and others are not. Second, under the PCA, monthly reports would be provided to the Commission Staff, and to other parties, that show the PCA accounting entries and supporting documentation, as well as explain the events or conditions that caused the rebate or surcharge entry. These monthly reports would permit some review to occur as the PCA entries are being recorded over time.

Deferred Accounting

In contrast to the PCA mechanism, the implementation of deferred accounting through a Commission order would not determine the process to change rates related to the deferred costs.

Under deferred accounting the changes in costs are set aside, but the determination of the method and timing of any increases or decreases in rates would be addressed in a separate future proceeding.

In addition, the determination of the reasonableness and prudence of the deferred costs would be subjected to a thorough review of the deferred costs. The Commission has been very clear in its previous orders regarding deferred accounting that the reasonableness of the costs and the potential ratemaking treatment of the deferred costs are subject to evaluation and review in subsequent proceedings. Furthermore, the Commission has stated that the burden of demonstrating the reasonableness of the costs rests with the Company.

While the deferred costs are subject to thorough review in subsequent proceedings, deferred accounting does provide immediate relief to the Company to deal with the additional costs incurred in between rate cases or during the pendency of a general rate case. The effect of the deferred accounting entries is to set aside the change in costs for the opportunity for later recovery.

"Side Account"

As indicated in the table above, the "side account" or "side record" could be implemented without an order from the Commission, i.e., the Company could simply keep track of the change in costs each month essentially on a work sheet. No accounting entries would be made for either regulatory or financial purposes, and there would be no predetermined rate making or cost recovery process. This type of "side account" would not provide any form of relief to the Company to deal with the additional costs incurred by the Company.

Q. Is the Company requesting that a PCA mechanism be implemented for the January through October 2002 period?

A. No. The Company is not requesting a PCA for the January through October 2002 period. The Company is requesting that the Commission authorize deferred accounting treatment, which as shown above, is distinctively different that a request for a power cost adjustment mechanism.

Q. Would you please further explain the specific accounting treatment being requested by the Company?

A. Yes. The temporary deferred accounting treatment requested by the Company would involve FERC Accounts that contain revenues and expenses that are directly affected by the level of hydroelectric generation and wholesale electric and natural gas market prices. The wholesale electric market prices affect the purchases and sales of electricity that the Company must make on a day-to-day and month-to-month basis to balance resources with load requirements. The wholesale natural gas market prices affect the purchases of natural gas to run the Company's gas-fired combustion turbines. The hydroelectric generation and wholesale electric and natural gas market prices are highly variable, unpredictable and beyond the control of Avista.

There are continuing concerns regarding available hydroelectric generation as we enter into 2002. With reservoirs currently below normal levels, unless the region receives above-normal precipitation for the upcoming streamflow runoff period, Avista will experience below-normal hydroelectric generation and commensurate increased costs. Without some form of accounting treatment authorized by the Commission, the additional costs during this period would be absorbed by the Company, which would further compound the Company's current weak financial situation.

In addition, during the past year the Company entered into fixed-price natural gas contracts for a portion of the natural gas needed to operate its natural gas-fired projects. With the continued decline in wholesale electric and natural gas prices, the pricing for these natural gas contracts are well above the current wholesale market prices for natural gas and electricity. These contracts were entered into during the recent year of high market prices and high price volatility, and, therefore, are a direct result of the extraordinary market conditions that the West has experienced in 2000 and 2001. Deferred accounting treatment for the period January through October 2002 is necessary in order to provide Avista with the opportunity for recovery of these additional costs. Mr. Lafferty provides additional details related to these natural gas costs, as well as the prudence of these natural gas contracts.

Finally, during the January through October 2002 period, the Company will continue to incur the fixed costs associated with the new small generation projects, discussed in Mr. Lafferty's testimony, as well as the fixed costs associated with the Coyote Springs II project when it comes on line in June 2002. The Company is proposing to defer these fixed costs during the pendency of the general rate case.

Mr. Johnson explains the proposed deferred accounting calculations to set aside the costs described above, and his Exhibit _____ (WGJ-3) includes a current estimate of the costs that would be deferred during January through October 2002 of $19.5 million for the Washington jurisdiction.

Q. What is the current status of reservoirs in the Northwest?

A. Attached as Exhibit _____ (KON-1) is a graph that shows the "System Energy Content" for reservoirs in the Northwest coordinated hydroelectric system. This graph, which is prepared on a weekly basis by the Northwest Power Pool Coordinating Group, shows the amount of storage draft available from Northwest reservoirs on both an operation planning basis and actual basis for the current operating year.

The "x" axis on the graph represents the current 12-month operating year from August 2001 through July 2002. The "y" axis represents the amount of storage draft available from Northwest reservoirs, measured in thousands of megawatt-months.[1]

The solid line on the graph represents the amount of storage water that would normally be withdrawn from the reservoirs over the course of the operating year, with a return to near-full reservoirs at the end of July 2002. The asterisks (*) on the graph indicate the actual level of storage water available as we progress through the operating year.

As of the first week of November 2001, the graph shows that actual reservoir elevations were down approximately 24,000 megawatt-months (as indicated by the asterisks). Under normal conditions, reservoirs would be drawn down only 12,000 megawatt-months at that point in time. Therefore, as of the first week of November, reservoirs were below normal levels by approximately 12,000 megawatt-months. This is equivalent to 1000 average megawatts of energy over an entire 12-month period.

Q. Please explain why the Company is requesting temporary deferred accounting treatment for the fixed costs associated with the small generation projects and Coyote Springs II.

A. The Company's current financial condition makes it necessary for Avista to request temporary deferred accounting treatment for the power supply related costs described above, including the fixed costs associated with the small generation projects and Coyote Springs II. As

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[1] A "megawatt-month" is equal to one average megawatt of energy for every hour of the month.

stated earlier, the total estimated costs to be deferred are approximately $19.5 million for the January - October period.[2]

An alternative to deferred accounting treatment of these costs is to increase the interim rate increase request in this filing by an additional 10%, from 12.4% to 22.4%. However, an interim increase of 22.4% together with the existing surcharge of 25% would result in an overall increase in place of 47.4%, which we believe should be avoided if possible. Deferred accounting treatment of these costs would provide the regulatory relief needed by the Company for these costs, without imposing an additional rate increase on customers, over and above that already proposed in this filing. The use of deferred accounting would provide the opportunity to spread these costs out over a longer period of time.

The Company has provided extensive documentation regarding the prudence of these resources. It is appropriate, under the current circumstances, to set aside the costs associated with these projects for the opportunity for later recovery, pending the outcome of the prudence review in this general rate case.

Q. Is the Company proposing to defer 100% of the additional power supply related costs during the temporary deferral period?

A. No. Although the Company believes it would be reasonable to defer 100% of the differences in these accounts, the Company is proposing to defer 90% of the differences in these accounts. Deferral of 90% would result in the Company foregoing the opportunity to fully recover its costs to serve customers during this period. Given the Company's current financial condition, it is important, however, for the Company to have the ability to recover a substantial

[2] The estimate for the calendar year 2002 is $23.7 million.

portion of the costs to serve its customers, in order to improve its financial condition as soon as possible.

As Mr. Eliassen has explained, the financial community has expressed significant concerns regarding the absence of some form of accounting treatment beginning in January 2002, that would allow the Company the opportunity to recover the costs associated with serving its customers. The absence of the opportunity to recover these costs would result in a continuation or deterioration of the Company's weak financial condition.

Q. Has deferred accounting been used in the past for these types of costs?

A. Yes. The Commission has the authority to authorize the deferral of these costs, as proposed by the Company in this filing, and such an authorization would be consistent with existing and historical ratemaking practices. The accounting treatment would provide the relief needed by the Company for these costs during this period. As stated earlier, the Company has filed testimony, exhibits and other documentation to support the prudence of the purchased gas costs, the small generation projects and the Coyote Springs II project. Deferred accounting treatment would provide an accounting basis to set aside these costs for the opportunity for later recovery, pending the outcome of the prudence review.

Q. Will the Company have an opportunity to profit from the temporary deferred accounting treatment?

A. No. The deferred costs do not include a profit component for the Company. In fact, because the Company is proposing to defer 90% of the increased costs instead of 100%, the Company, even with the deferred accounting authorization, would still not fully recover its costs to provide service to its customers in 2002. Mr. Peterson provides information regarding Avista's financial results for 2002.

IV. POWER COST ADJUSTMENT MECHANISM

Q. Please provide a brief overview of the Company's request for a Power Cost Adjustment (PCA) mechanism.

A. Through this filing the Company is requesting that the Commission authorize the implementation of a power cost adjustment mechanism at the conclusion of this case. The financial impacts of the variation of power costs experienced by the Company from year to year would be "smoothed-out" through the PCA. As Mr. Peterson explains in his testimony, the PCA would add stability to the financial results of the Company, and provide lower rates to customers than would otherwise occur.

Q. Is there any special significance to the name of this type of mechanism?

A. Unfortunately in Washington there seems to be some negative connotations associated with anything that looks like or sounds like an adjustment mechanism involving power costs. In the past there has been a variety of adjustment mechanisms used in the industry, some of which have been referred to as PRAM (Periodic Rate Adjustment Mechanism), ERAM (Energy Rate Adjustment Mechanism), ECAC (Energy Cost Adjustment Clause), CRAC (Cost Recovery Adjustment Clause), and FAC (Fuel Adjustment Clause), just to name a few. Not only has there been a variety of names, but also a variety of designs, i.e., some mechanisms have different cost components than others.

Irrespective of the name of the mechanism, it is our hope is that any negative connotations can be set aside so that we can focus on implementing a mechanism that provides benefits to both the Company's customers and its shareholders. With respect to Avista's current filing, the Company has focused its efforts on a mechanism that is simple to understand, simple to implement, and provides benefits to all stakeholders.

Q. What are the specific conditions or circumstances that have caused the Company to propose the PCA?

A. There are some major external influences that cause the costs incurred by the Company to serve its customers to vary significantly from year to year. This variability is driven primarily, either directly or indirectly, by changes in hydroelectric generation conditions, wholesale electric market prices, and wholesale natural gas market prices, all of which are highly variable, unpredictable and beyond the Company's control.

Q. Please explain the variability in costs associated with hydroelectric generation.

A. Over half of the energy used by Avista to serve its customers[3] comes from hydroelectric generation. The Company owns and operates the Noxon Rapids and Cabinet Gorge hydroelectric projects on the Clark Fork River in Western Montana and Northern Idaho, and six hydroelectric projects on the Spokane River. Under normal hydroelectric conditions, these projects provide approximately 450 aMW of energy to serve customers.

In addition to the Company-owned projects, Avista has rights to power from hydroelectric projects on the middle section of the Columbia River (Mid-Columbia Projects), including the Douglas County PUD's Wells Project, Chelan County PUD's Rocky Reach Project, and Grant County PUD's Wanapum and Priest Rapids Projects. Under normal hydroelectric conditions, these projects provide approximately 100 aMW of energy to serve Avista's customers.

[3] The Company's retail load under normal weather conditions is approximately 956 aMW.

The low-cost energy from Avista's hydroelectric generation (both owned and contracted) is one of the primary reasons Avista has been a low-cost provider of electricity to its customers. The Company's customers have received significant benefits from Avista's low-cost hydroelectric resource base for many years.

This low-cost hydroelectric resource base, however, carries with it a significant amount of variability. Hydroelectric generation from one year to the next can be significantly higher or lower than the prior year. Retail rates to customers, however, are based on "normal" hydroelectric conditions, calculated based on an average of hydroelectric conditions (e.g., an average of 60 historical streamflow conditions). If actual hydro conditions are different than "normal" or average, the Company absorbs the changes in costs (up or down) associated with the difference in hydroelectric generation. The record-low hydroelectric conditions in 2001 and the resulting adverse financial impacts are a good example of the potential variability of costs associated the ownership and operation of a hydroelectric system. For 2001, hydroelectric generation will be approximately 194 aMW below normal, which has resulted in a gross increase in costs of approximately $290 million on a Washington jurisdictional basis. For comparison purposes, the Company's annual retail revenue in Washington is approximately $240 million.

Q. How do you measure the financial impact of hydroelectric generation being higher or lower than normal?

A. The financial impact of hydroelectric generation being higher or lower than normal is equal to the change in hydroelectric energy times the short-term wholesale market price of power. For example, if hydroelectric generation in a year is 100 aMW below normal and the average wholesale market price for the year is $50/MWh, the adverse financial impact would be $43.8 million (100 aMW x 8760 hours x $50/MWh = $43.8 million). In this case, the cost to replace the 100 aMW of reduced hydroelectric generation is $43.8 million. Because the incremental cost of hydroelectric generation is near zero, a reduction of hydroelectric generation does not have a corresponding reduction in costs. Thus, the financial impact is equal to the reduction in hydroelectric MWh times the market price to replace the energy.

In addition, the financial impacts from a change in hydroelectric generation are not symmetrical. Historically, the short-term wholesale market prices during adverse streamflow conditions have tended to be higher than the market prices under favorable hydro conditions. This intuitively makes sense because adverse streamflow conditions result in less energy available, a tighter supply and demand situation, and a tendency for prices to go up. Conversely, favorable streamflow conditions result in more energy available to meet demand, and a tendency for prices to go down.

As an example, if the Company were to experience below-normal hydro generation of 100 aMW in 2002 and the average market price were $50/MWh, the adverse financial impact would be approximately $43.8 million. If in the following year, hydro generation was above normal by 100 aMW, and because of the surplus energy available in the region the market price declined to $25/MWh, the favorable financial impact from the above-normal hydro generation would be $21.9 million. Therefore, an equivalent increase or decrease in hydroelectric generation (MWh) will not have an equivalent financial impact, because of the change in wholesale market prices that can occur. Stated another way, the financial benefits in "good" water years do not tend to offset the adverse financial impacts during "bad" water years.

The financial impacts from changes in hydroelectric conditions are tied directly to the wholesale market price of power and are inseparable. Therefore, changes in hydroelectric generation and changes in wholesale market prices are two critical components of a PCA mechanism.

Q. If the Company were in a surplus condition, would it still experience adverse financial impacts from below-normal hydroelectric conditions?

A. Yes. I will use an example to illustrate. If the Company had surplus energy on its system of 100 aMW (under normal hydroelectric conditions) at the time retail rates were set in a general rate case, the assumption in the rate case would be that Avista would sell the surplus energy at the prevailing wholesale market price of, for example, $35/MWh. The revenue from these surplus sales (100 aMW x 8760 hours x $35/MWh = $30.7 million) would be credited against the costs to serve retail customers in the general rate case, such that the overall retail rate being charged customers is lower than it otherwise would be.

Subsequent to the rate case, if Avista experienced below-normal hydroelectric generation of 100 aMW, in this example the Company would still have adequate resources to serve its customers, but because of the reduced hydroelectric generation, it would not have surplus energy to sell. The result would be that customers would receive a credit of $30.7 million through the base retail rates set on a normalized basis, but the Company would be short revenues of $30.7 million, because there is no surplus to sell. Therefore, whether the Company is in a surplus or deficiency condition, a reduction in hydroelectric generation creates an adverse financial impact to the Company.

Q. Please explain how changes in wholesale natural gas prices cause variability in the costs to serve Avista's retail electric customers.

A. Avista's resource base currently includes two simple-cycle combustion turbine projects, Rathdrum and Northeast.[4] Both projects run on natural gas, and Northeast will also run of fuel oil. In addition, Avista is currently constructing the Coyote Springs II combined cycle combustion turbine project, which is scheduled to come online in June 2002. Avista will own 50% of this natural gas-fired project, which will be equal to approximately 140 MW. Furthermore, Avista is currently adding 25 MW of natural gas-fired reciprocating engines at the Boulder Park site in the Spokane valley.

Therefore, Avista will have 140 MW of base-load natural gas-fired generation in Coyote Springs II, with a heat rate of approximately 7000 BTUs/KWh, and approximately 255 MW of natural gas-fired peaking units with heat rates ranging from approximately 9,000 BTUs/KWh for Boulder Park to 13,000 BTUs/KWh for Northeast.

The volume of natural gas necessary to run these projects at full load is approximately 80,000 dekatherms/day.[5] The Washington jurisdictional portion, at 66.29%, would be approximately 53,000 dekatherms/day. For comparison purposes, Avista's <u>retail natural gas load</u> in the Washington jurisdiction averages approximately 50,000 dekatherms/day over the course of a year. Therefore, the volume of natural gas required to run these projects is substantial.

It is necessary to have a tracking mechanism for changes in these natural gas costs, for the same reasons that a PGA tracker is in place for the retail natural gas business; the market prices for the natural gas are unpredictable, highly variable and beyond the control of the Company.

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[4] Rathdrum was constructed by Avista, but is leased through a sale and lease-back arrangement. Avista operates the project, which has two units totaling 164 MW of capacity. Avista owns the Northeast project, which has two units totaling 59 MW of capacity.

[5] This figure is based on the annual average maximum daily natural gas consumption including air permit operating limitations.

The operation of the projects is dependent on the cost to generate electricity from the projects, versus the cost to purchase electricity from the short-term wholesale electric market. If it is less expensive to burn natural gas to produce electricity than to buy from the electric market, then the projects would be dispatched, otherwise the plants will remain on standby and would be available for reserves as needed.

Because the heat rates are so different for each of these projects, the Company will use a portfolio approach over time in purchasing natural gas for the projects. For Coyote Springs II, the Company may layer in advanced purchases for a portion of the natural gas requirements over time. For the peaking units, the purchases will tend to be closer to the time that the units would run. Mr. Lafferty provides additional discussion related to the purchases of natural gas for these projects.

It is important to include the changes in these natural gas costs in a PCA for at least two reasons. First, because the volume of natural gas for these projects will be relatively large, and the market price of natural gas is so highly variable and unpredictable, there will be significant variability in the costs of natural gas for these projects. Second, the peaking units provide a hedge, to some degree, for below-normal hydroelectric conditions. When hydroelectric generation is below normal, the peaking units can be run to cover load requirements, which would avoid higher-priced purchases from the short-term wholesale electric market. These projects would only be run if their costs are lower than the wholesale electric market price and there is a benefit to run them. Therefore, it would be appropriate to include these costs and benefits in the PCA.

Q. Are there measures that can be taken to reduce the variability of costs incurred by the Company?

A. Yes. A number of strategies are in place to mitigate the variability of power costs to the Company, and ultimately to its customers. The overarching strategy is to minimize exposure to high-priced short-term market purchases. Purchases and sales in the short-term market cannot be completely avoided, because of the need to balance resources to load requirements within each month, within each day, and across the months of the year, under constantly changing conditions.

For resource planning purposes, Avista prepares detailed analyses of the adequacy of its resources to cover load requirements for each year of the next three to five years. Within each of these years, the Company runs hourly scenario analyses related to the potential variability of retail loads and the potential variability of hydroelectric generation. Based on these scenarios, the Company's plans for base-load and peaking resources to cover its load requirements, for all but the most unusual events. Base-load resources are acquired to generally cover the basic energy load requirements. Peaking resources are generally used to cover variability of retail loads, variability of hydroelectric generation, and forced outages of base-load thermal plants.

In addition, the Company has assembled a diversified portfolio of resources. These include the continued pursuit of demand-side measures, and supply-side generation including the following:

- Hydroelectric - Clark Fork & Spokane River Projects and Mid-Columbia Agreements
- Coal-fired - 15% of Colstrip Units 3 & 4
- Wood waste-fired - Kettle Falls
- Base-load natural gas-fired combined cycle CT - 50% of Coyote Springs II

- Simple cycle natural gas-fired CTs - Rathdrum and Northeast[6]
- Natural gas-fired reciprocating engines - Boulder Park

In addition to the generating resources, the Company also layers in medium-term electricity purchases, e.g., two to five years, as needed to fill-in deficiencies. Avista continues to upgrade its hydroelectric generating units to gain efficiencies. As an example, the recent upgrade of Cabinet Gorge Unit 3 resulted 15 MW of increased capacity and approximately 2 aMW of additional energy from the use of the same amount of water. The Boulder Park natural gas reciprocating engines provide diversity within the project. There are six units of four megawatts each, therefore, if one unit goes down, the remainder can continue to run. These units have a heat rate of approximately 9000 BTUs/KWh, which is lower than either Rathdrum or Northeast.

Additional diversity is provided through natural gas purchases for the generators. In addition to the ability to layer in the gas purchases over time, the Company has the flexibility to deliver the natural gas purchased to either Coyote Springs II, Rathdrum, Northeast or Boulder Park. As an example, if Coyote Springs II goes down, the natural gas can be delivered to Rathdrum to replace the Coyote Springs II generation, if Rathdrum is the most economic choice. Mr. Lafferty provides additional details related to Avista's resource planning and operations.

Therefore, the Company has strategies in place to reduce the variability of power supply related costs, including but not limited to, 1) a diversified mix of resources, 2) sufficient energy resources to cover basic load requirements, 3) peaking resources to cover variability of loads, hydroelectric generation and base-load thermal generation, and 4) layering in electricity and fuel

[6] Northeast also operates on fuel oil.

supply purchases over time. Even with these strategies, however, there will continue to be significant variability of costs that need to be addressed through a PCA mechanism.

The goal with regard to a PCA is to implement a mechanism that will provide more financial stability for the Company, resulting in lower rates to customers than would otherwise occur, while at the same time minimizing the frequency and magnitude of price changes to customers. The strategies outlined above to reduce the variability of costs will support this goal.

Q. Has the Company prepared estimates of the variability of power costs that could be experienced by Avista in the future?

A. Yes. This information is available from the Prosym Hourly Dispatch Model run prepared by Mr. Kalich. The Prosym Model calculates the costs to serve Avista's load requirements under varying hydroelectric and market price conditions. The model economically dispatches base-load thermal plants and gas-fired peaking units on an hourly basis, and shapes the available hydroelectric generation to the more valuable heavy-load hours.

The Model was run based on the streamflow conditions that occurred each year for the 60-year period 1929 to 1988. The variation in power costs each year is illustrated on Exhibit _____ (KON-2). The graph shows that costs can increase as much as $56 million in a year (1931), and decrease as much as $24 million (1959). It should be noted, however, that the variability in costs could potentially be much greater than those shown on this graph, due to a number of factors including, but not limited to, hydroelectric generation or market prices being substantially different than those included in the study, extended outages of major generating equipment, and major changes in loads.

The figures on the graph, however, reflect the expected variability of costs. The PCA would smooth-out the financial impacts of these varying costs, and as stated earlier, result in lower costs to customers than would otherwise occur.

Q. In the current electric utility industry environment, is a PCA more or less important than in the past?

A. The implementation of a PCA for Avista is more important now than ever before. The industry has recently experienced unprecedented high wholesale market prices and unprecedented volatility. Avista has also just experienced record low hydroelectric streamflow conditions. This variability of hydroelectric generation for Avista, as a hydro-based utility, amplifies substantially the exposure to purchase replacement power in a volatile wholesale market, as compared to a utility with less reliance on hydroelectric resources. This reliance on hydroelectric generation in a volatile wholesale market makes a PCA especially important for Avista.

Q. Has the Commission previously outlined criteria related to the adoption of PCA mechanisms?

A. Yes. In the Commission's Sixth Supplemental Order, dated December 19, 1988, in Docket No. U-81-41 (Re-opened), it outlined three policies related to the implementation of a power cost adjustment mechanism.

First, the Commission ruled that customers should receive the benefit of a cost-of-capital reduction related to implementation of such a mechanism. The Commission explained that the improved financial stability for the utility, should result in reduction in the cost of capital, and the benefit of this reduction should be provided to customers.

Second, the Commission ruled that a power cost adjustment mechanism should be linked to those factors which are weather-related. With regard to this ruling, the Commission stated the following on Page 21 of the Order:

> "Tying the ECAC to this link between weather changes and operating costs is central for two very important reasons. First, weather patterns are beyond the control of the company, and, second, and most significantly, the vast majority of customers can intuitively understand the weather/cost link." (emphasis added)

Third, the power cost adjustment mechanism should exclude the cost of new long-term resources. The purpose of the mechanism is to recognize the variability of the costs of operating existing power supply resources.

Q. Please summarize the specific PCA proposal by Avista.

A. In developing its proposal, the Company focused its efforts on a mechanism that would be simple to understand, simple to implement, provides benefits to all stakeholders, and that complies with the criteria outlined by the Commission in Docket No. U-81-41.

The mechanism is simple in that the calculations involve a simple comparison of the dollars in four FERC Accounts, along with a couple of adjustments that are explained by Mr. Johnson. The PCA adjustment would be based on a comparison of the actual dollars in the four accounts each month, with the dollars embedded in base retail rates for those same four accounts, as approved by the Commission in the last rate case. These four accounts include those costs that are driven primarily, either directly or indirectly, by changes in hydroelectric generation conditions and wholesale electric and natural gas market prices, all of which are highly variable, unpredictable and beyond the Company's control.

Ninety percent (90%) of the dollar differences in these accounts (whether increases or decreases) would be set aside each month to a PCA Balancing Account. When the Account reaches 10% of base retail revenues (currently $23 million), a rate adjustment surcharge or rebate would be triggered. The $23 million surcharge or rebate amount would be removed from the PCA Balancing Account, and would be spread to customers over a twelve-month period. The Balancing Account would begin again to accrue a balance in either the surcharge or rebate direction. The accounting is explained in more detail by Mr. McKenzie.

Q. Please explain how the Company's PCA proposal complies with the three criteria previously outlined by the Commission.

A. First, with regard to the cost of capital reduction, the Company has proposed in this filing to flow through to customers a return on equity benefit associated with the implementation of a PCA. In addition, as explained by Mr. Avera, the implementation of a PCA would reduce the Company's overall cost of capital over time, which would result in lower costs to customers than would otherwise occur.

Secondly, the changes in costs included in the PCA would <u>exclude</u> the costs associated with any new long-term resources, and include only the change in costs associated with existing resources. The costs of any new long-term resources that would normally be recorded in these four FERC Accounts would be adjusted out until the costs are reviewed by the Commission in a future proceeding.

With regard to the weather-related criteria, the Company has narrowed the scope of the mechanism to include only those costs that are driven primarily, either directly or indirectly, by changes in hydroelectric generation conditions and wholesale electric and natural gas market prices. I believe Avista's PCA proposal complies with this criterion, if not in letter, then certainly in spirit. As stated earlier, the Commission explained that the purpose for adopting this criterion was to focus on those costs that are "beyond the control" of the Company, and which "customers can intuitively understand" the reason for the change in costs.

Variability of costs caused by changes in hydroelectric generation, wholesale electric market prices, and natural gas market prices are beyond the control of the Company, and I believe customers understand, not only the changes in costs that are caused by hydroelectric generation, but also the changes related to wholesale electric and natural gas prices. I believe this is especially true in light of the wholesale electric and natural gas market conditions that the region experienced in 2000 and 2001. A considerable amount of time was devoted by utilities, regulators and other industry participants to educate customers on the changes in market prices and the resulting change in power costs to utilities.

In addition, the increases and decreases in the wholesale price of natural gas have been passed through to retail natural gas customers on a regular basis through Purchased Gas Adjustment (PGA) mechanisms. These changes in costs are tracked through the PGA because the costs are unpredictable, highly variable and beyond the control of the Company. I believe retail natural gas customers generally understand the rate adjustments related to the wholesale price changes. In a similar manner, customers would understand how wholesale natural gas prices would affect the cost to generate electricity for gas-fired generating projects, as well as how wholesale electric prices would affect the short-term purchases and sales of electricity made by Avista to balance its resources with its load requirements on an hourly, daily and monthly basis.

Finally, as explained earlier, the change in costs associated with varying hydroelectric conditions is based on the wholesale price of power, and therefore, the wholesale price of power is integral to the determination of the impacts of changes in hydroelectric generation. In addition, when the Company's natural gas-fired resources are dispatched, it results in lower costs because it is less costly to burn gas and run these units than to make purchases from the wholesale electric market. For all of these reasons, it is reasonable and appropriate to include in the PCA changes in costs associated with hydroelectric generation, and wholesale electric and natural gas market prices, as proposed by the Company.

Q. Are there other issues that the Company has taken into consideration in developing the proposed PCA?

A. Yes. Avista has proposed to set aside 90% of the changes in costs through the PCA each month instead of 100%. The Company has included this component in the proposal in response to previous concerns expressed by parties related to a sharing between customers and shareholders. Even though the costs that would be tracked in the PCA are generally beyond the control of the Company, the 90%/10% sharing would theoretically provide the Company with an additional incentive to make the best possible economic decisions on behalf of customers.

With regard to the frequency of rate adjustments, the proposed PCA Balancing Account, explained by Mr. McKenzie, would serve to allow the plusses and minuses of the monthly PCA entries to offset one another over time. The strategies outlined earlier related to resource planning and resource operations would also serve to reduce the variability of costs and reduce the frequency of rate adjustments.

Q. Would implementation of the PCA affect in any way the Company's Integrated Resource Planning or RFP processes?

A. No. The Company would continue to conduct IRP and RFP activities related to the planning and acquisition of resources. In addition, as stated before, the costs included in the PCA would exclude the costs associated with any new long-term resources, and include only the change in costs associated with existing resources. The costs of any new long-term resources would not be included until the costs are reviewed by the Commission in a future proceeding.

Q. Please provide a brief overview of the Company's experience with the PCA mechanism in the Idaho jurisdiction.

A. Avista's PCA in Idaho has been in place for approximately 12 years (since 1989). The mechanism has been modified a few times since its inception. These modifications were made essentially to "fine-tune" the mechanism based on the experience gained over time with the mechanism.

Rate adjustments, whether an increase or decrease, are preceded by a filing by the Company and an audit by the IPUC Staff and other interested parties. The Company provides monthly reports to the Commission that include the PCA calculations and supporting documentation.

The Idaho PCA has been effective in smoothing-out the financial impacts associated with varying hydroelectric conditions and wholesale electric and natural gas market prices. Costs associated with new long-term resources are subject to review by the Commission prior to recovery of the costs through the PCA.

Q. How does the Company's PCA proposal in this filing compare to the PCA that currently exists in its Idaho jurisdiction?

A. Avista's proposal in this case is essentially identical to the current PCA in the Idaho jurisdiction. The mechanism is simple to understand and to implement, and would be effective in dealing with the variability of costs experienced by the Company.

The Idaho jurisdiction, however, represents only one-third of Avista's retail electric business, with the remaining two-thirds in Washington. Avista needs a similar PCA in the

Washington jurisdiction in order to achieve the financial stability that would result in lower costs to its customers.

Q. Do other utilities in the Northwest have PCA mechanisms that track similar power supply related costs?

A. Yes. In addition to Avista's PCA in the State of Idaho, Idaho Power Company also has a PCA in that jurisdiction. In Oregon, PCAs were recently approved for both Portland General Electric and Pacificorp.

Furthermore, as Mr. Avera stated in his direct testimony in this case, beginning on page 59: "RRA's recent study[7] indicated that only 16 state jurisdictions do not currently have energy cost pass-through mechanisms in place, including 10 states that have largely completed a transition to retail competition. Of the 10 states where no substantive restructuring of the electric utility industry is underway, only two jurisdictions - Utah and Washington - have not established power cost adjustment clauses."

V. 60-YEAR VS 40-YEAR WATER RECORD

Q What has the Company proposed in this case related to the water record to use in normalizing hydroelectric generation for ratemaking purposes?

A The Company has proposed to use the streamflow conditions that occurred for the 60-year period 1929 to 1988 to represent average water conditions for hydroelectric generation. This water record has been used by Mr. Kalich to normalize hydroelectric generation for ratemaking purposes.

[7] Regulatory Research Associates, Inc., "RECOVERY OF FUEL AND WHOLESALE POWER COSTS: WHO IS AT RISK AND WHO IS NOT?," Regulatory Focus, p. 2 (February 28, 2001)

Q Why is the Company proposing the use of the 60-year water record?

A Mr. Kalich explains in his testimony that Avista obtains the streamflow data from the Northwest Power Pool (NWPP) Headwater Benefits Study. The 60 years of streamflow data in the NWPP study is generally accepted in the region as reliable data, and is used by many in the region for studies related to hydroelectric operations.

This streamflow data is updated once every ten years, at which time an additional ten years of streamflow data is added. When the data is updated each ten years, the actual historical streamflow for each tributary, for each year beginning August 1928, is adjusted to reflect the most recent levels of irrigation and depletion levels. This requires a significant time commitment, which is why the data is updated only once every ten years. The most recent update, to add the 10 years of data from August 1978 to July 1988, was completed in 1993. Data for the years subsequent to 1988 has not yet been incorporated.

Streamflow records for the Clark Fork River, from which the Company receives the majority of its hydroelectric generation, are not available prior to 1928. Thus, we believe the available NWPP hydroelectric data for the 60-year period August 1928 to July 1988 (operating years 1929-1988) provides the best available data to determine normal hydroelectric generation conditions for rate making purposes.

I believe that a careful review of the evidence will show that the previously adopted 40-year rolling average methodology will not provide the best estimate of average water conditions for ratemaking purposes. The evidence includes a review of the actual historical water year data, and the water record used by others in the industry. In addition, Dr. Dukich provides extensive analysis showing that the use of the 60-year record is more appropriate for ratemaking purposes than the 40-year rolling average methodology.

The use of the water record for the 40-year period 1949-1988, based on the 40-year rolling average methodology, to normalize power supply costs for ratemaking purposes would decrease the Company's power costs by approximately $4.6 million per year on a Washington jurisdictional basis. Such an adjustment would be based on the inappropriate use of more favorable streamflow conditions for normalization purposes than can be justified with the available data.

Furthermore, page 18 of the Commission's Third Supplemental Order in Cause No. U-85-36, dated April 4, 1986, states as follows:

> "The Commission's decision does not mean that the Commission will use a rolling 40 years for all future cases. The Commission will evaluate alternatives proposed in future cases."

Q What does a review of the historical streamflow data show us?

A Page 1 of Exhibit No. ___ (KON-3) shows historical streamflow data for the Columbia River, as measured at The Dalles, Oregon, for the period 1879 through 1992. Each bar on this chart represents the percentage difference in the actual streamflow for that year as compared to the average streamflow for the 114-year period 1879 – 1992. For example, the streamflow at The Dalles for 1879 was 6% above the 114 year average.

This data is important in that it is based on actual measured streamflow on the Columbia River for the 114-year period 1879-1992. The Dalles is located on the lower end of the Columbia River and the streamflow measured there includes flows from Canadian reservoirs, the Clark Fork and Spokane Rivers, where Avista's owned hydroelectric generation resides, the Snake River, and many other tributaries. This is an industry accepted measuring point for flows on the Columbia River. The streamflow measurements at The Dalles, therefore, provide a good indicator of the precipitation, and ultimately the streamflow, that occurred in the region for this 114-year historical period.

If one were to select a period of water years from the available data to serve as an average condition for ratemaking purposes, it would be very important to look at the actual streamflow data available to determine whether there are any obvious problems with the period of years chosen.

Page 2 of Exhibit No. ___ (KON-3) presents the same data as Page 1, but a smoothing technique, using a 5-year average, has been applied to smooth out some of the year-to-year variability. For example, the value shown on Page 2 for 1981 is the average for years 1979-1983, the value for 1982 is the average for 1980-1984 and so on.

Studies have concluded that there are no trends or cycles to the water record data. However, as shown on this bar chart, for this 114-year period there are clearly some extended periods of above-average water conditions, and some extended periods of below-average water conditions. If a selected period were to be chosen, it is important that the period selected include a reasonable balance of above-average water conditions and below-average conditions.

A visual observation of the bar chart on Page 2, without doing any further analysis, indicates that the 1949-1988 40-year period includes more water conditions that were above-average than below average. This graph by itself raises serious concerns about whether the 40-year average would be representative of average water conditions for ratemaking purposes.

More importantly, the bar chart on Page 3 of Exhibit No. ___ (KON-3) shows modeled hydroelectric generation for Avista's projects on the Clark Fork and Spokane Rivers, as well as the Mid-Columbia generation, for 1929 through 1987[8], and actual generation for 1988 through 2001.[9] Streamflow records for the Clark Fork River, where the majority of Avista's hydroelectric generation resides, are not available prior to September 1928.

Page 4 of this Exhibit includes the same data as Page 3, but with the same 5-year average smoothing technique applied that was used for the Columbia River data. It is even more apparent from a visual observation of the bar chart on Page 4 that the 1949-1988 40-year period includes more years with water conditions above-average than below-average. I believe this 40-year period is clearly not representative of the average streamflow conditions, when compared with the total historical streamflow data available for Avista's hydroelectric projects shown on this chart.

Q What historical period of water years do other parties in the region use in analysis involving hydroelectric generation?

A The historical water years used by others in the region that I am aware of are as follows:

1. The Northwest Power Planning Council (NWPPC) uses the 50-year record 1929 through 1978 for all operations studies. The NWPPC uses the full 60-year record 1929 through 1988 for its long-term planning studies.

2. The Northwest Power Pool (NWPP) uses the 1929-1988 60-year period to calculate the down-stream benefits from the release of water from upstream storage reservoirs (Headwater Benefits Study).

3. The NWPP uses the 1929-1988 60-year period to determine the "critical period" that is used in regional planning studies. The critical period occurs during the 1936-37 operating year.

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[8] Although the entire NWPP Headwater Benefits Study includes 60 years of data (July 1928 through June 1988), this chart includes calendar-year data for 1929 through 1987.
[9] Includes estimates for November and December 2001.

4. The Bonneville Power Administration (BPA) uses the 1929-1978 50-year period for ratemaking purposes.

5. BPA uses the 1929-1978 50-year period in developing its White Book Study. This study is used by BPA to develop its loads and resources balance, and is used in relation to some power contract provisions.

I am not aware of any regional studies that use the rolling average methodology, or the 40-year period 1949-1988 that has been recommended by Staff in prior cases.

I believe that a review of the evidence, including a review of the actual historical water year data, the water record used by others in the industry, and the analysis presented by Dr. Dukich clearly shows that the 40-year rolling average methodology will not provide the best estimate of water conditions for ratemaking purposes. The 60-year record should be used in this case for ratemaking purposes as proposed by the Company.

Q. Does that conclude your pre-filed direct testimony?

A. Yes.

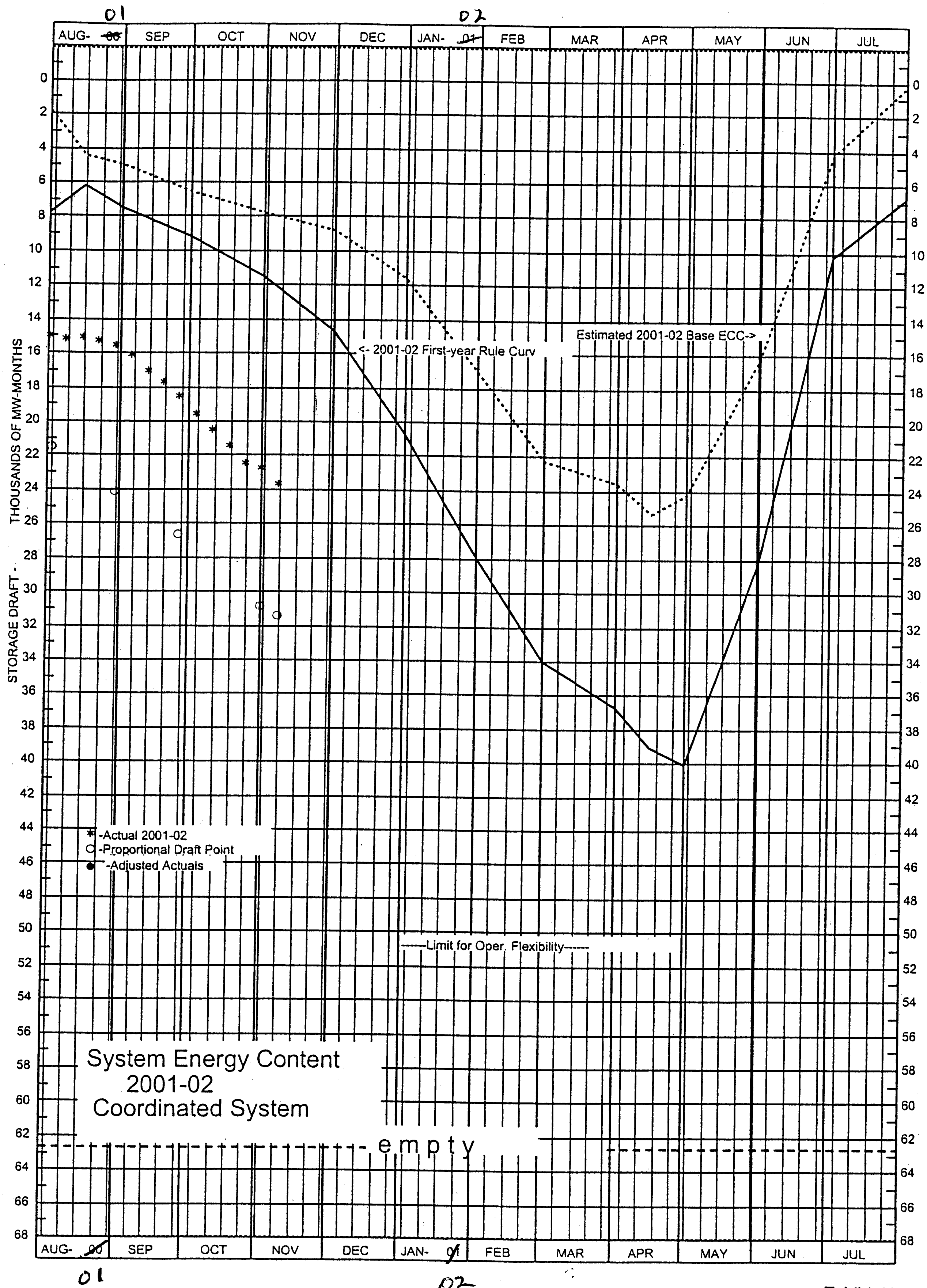
BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-01_______

EXHIBIT NO. _____ (KON-1)

WITNESS: KELLY O. NORWOOD, AVISTA CORP



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BEFORE THE

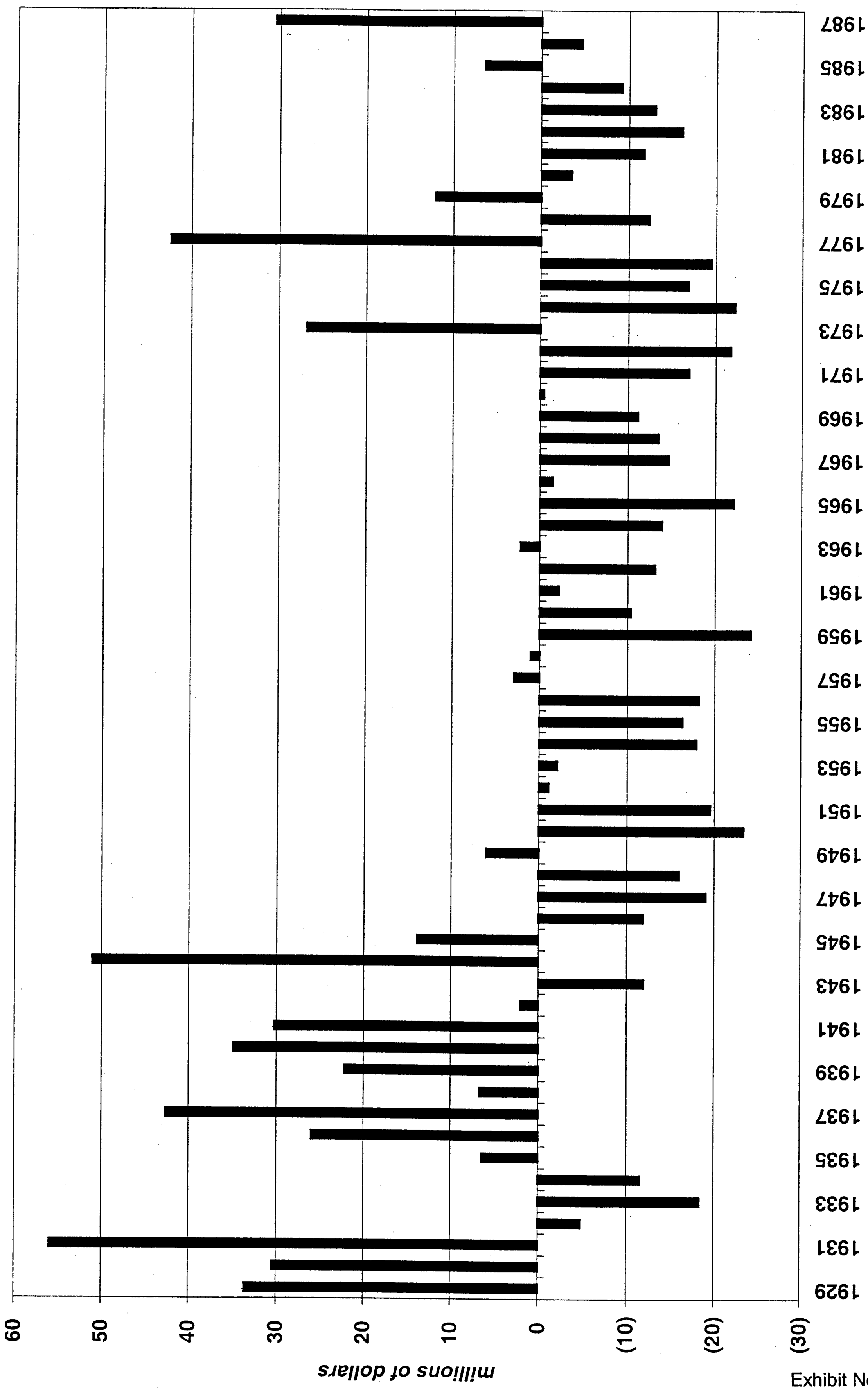
WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-01_______

EXHIBIT NO. _____ (KON-2)

WITNESS: KELLY O. NORWOOD, AVISTA CORP

Annual Variability of Prosym Model Run Power Supply Costs



BEFORE THE

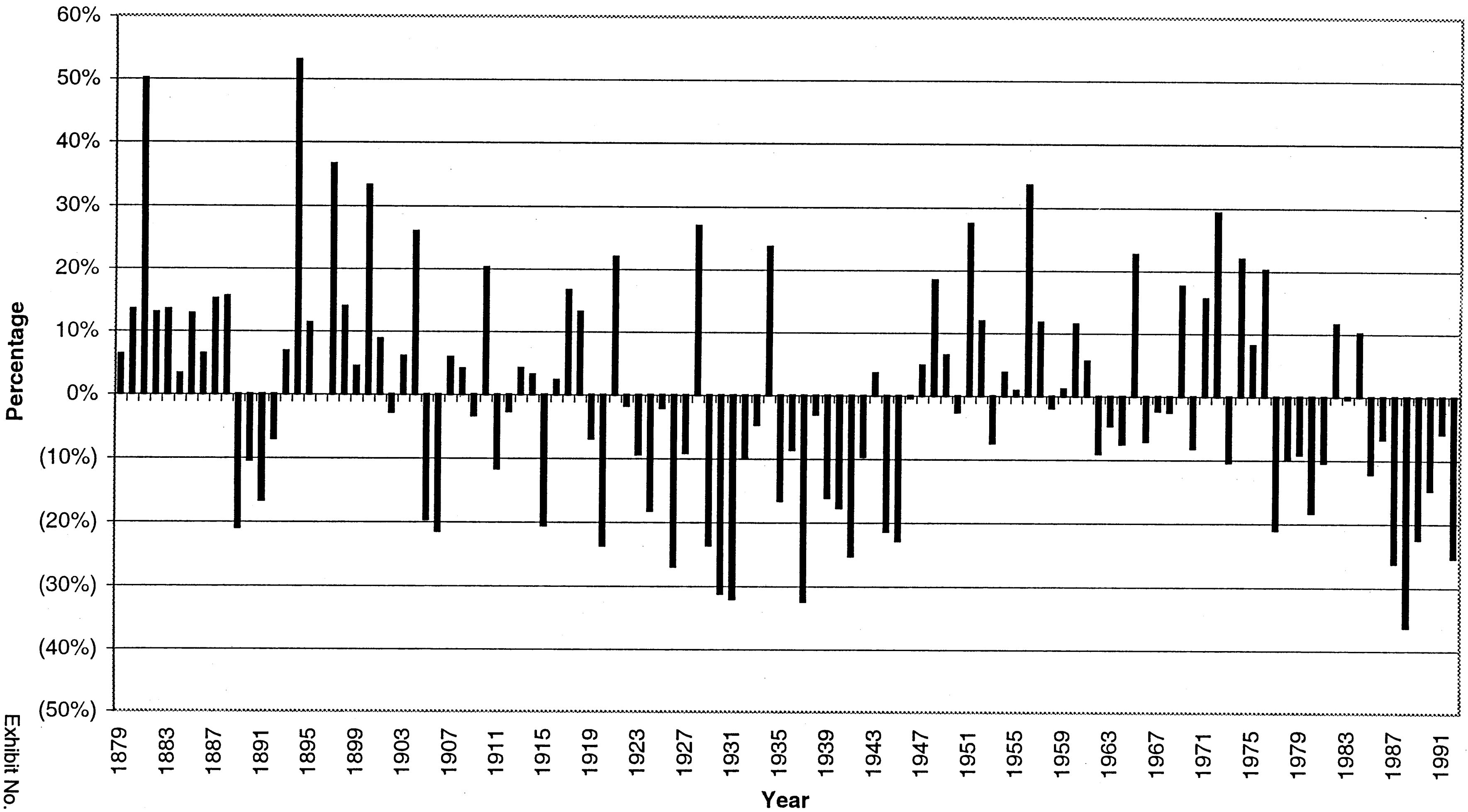
WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-01_______

EXHIBIT NO. _____ (KON-3)

WITNESS: KELLY O. NORWOOD, AVISTA CORP

Avista Corporation
Columbia River Natural Inflow at The Dalles
Percentage Deviation from the Mean by Year for 1879-1992



Avista Corporation
Columbia River Natural Inflow at The Dalles
Percentage Deviation from the Mean for 1879-1992
Smoothed Using a Five-Year Average

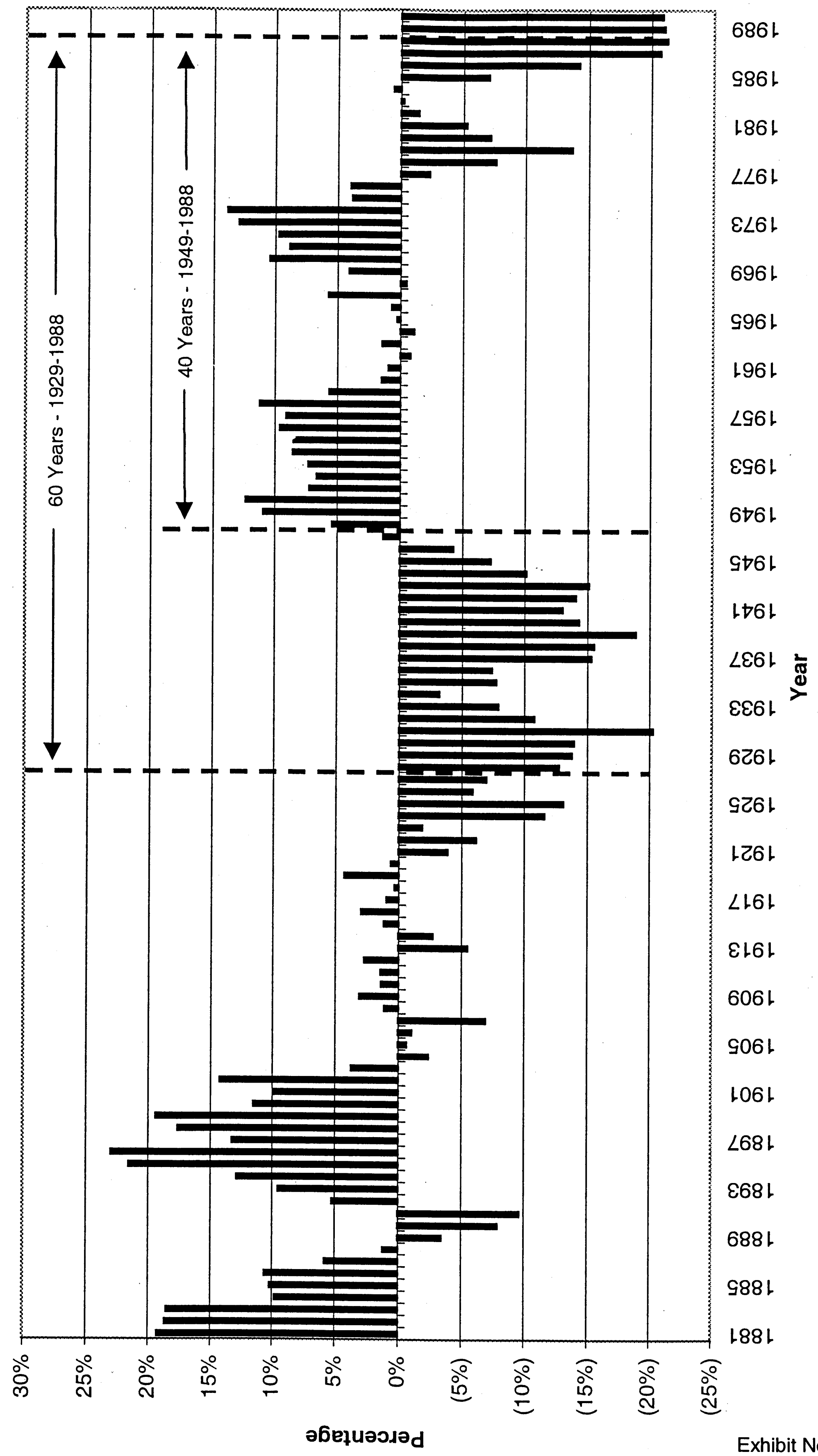
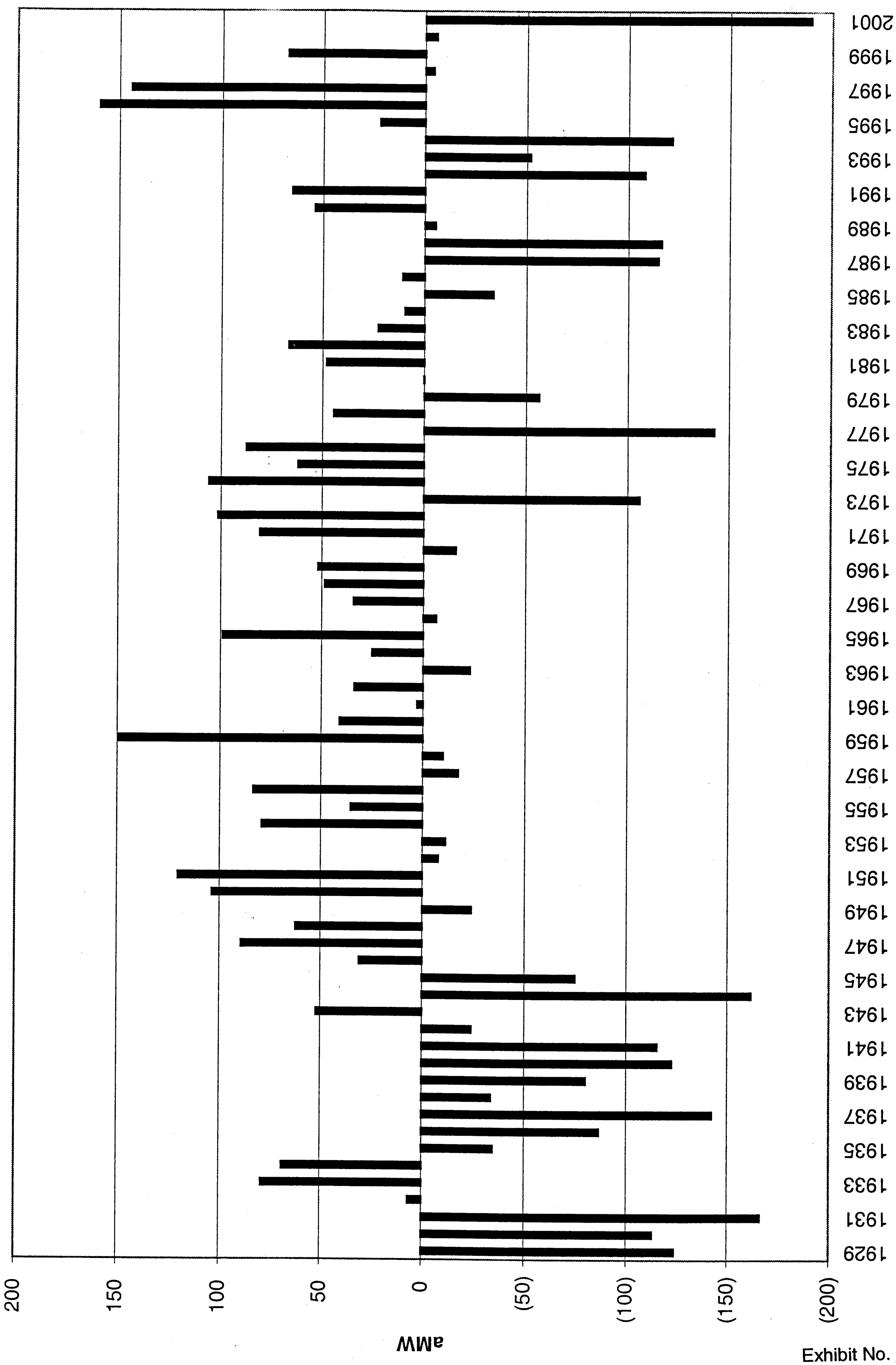


Exhibit No. __(KON-3)
Docket No. UE-01_____
Norwood, Avista
Page 2 of 4

Avista Hydro Generation (Clark Fork, Mid-C Contracts, and Spokane River)
Calendar Year Deviations from 1929-2001 Average



Avista Hydro Generation (Clark Fork, Mid-C Contracts, and Spokane River)
5-Year Rolling Average