Exhibit KLE-3 (______)
Docket No. UE-010395
Witness: Kenneth L. Elgin

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of the Avista Corporation's) Petition for Recovery of Expenditures) Related to Electric Deferral Mechanism))	DOCKET NO. UE-010395

EXHIBIT OF

KENNETH L. ELGIN

STAFF OF
WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION
RE: AVISTA PETITION FOR 37% ENERGY SURCHARGE

August 24, 2001

UE-000972

(P)

AVISTA Corp.

Avista Corporation
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June 22, 2000

Washington Utilities and Transportation Commission
1300 S. Evergreen Park Drive S. W.
P.O. Box 47250
Olympia, Washington 98504-7250

Attention: Ms. Carole Washburn, Executive Secretary

Enclosed for filing with the Commission are nineteen copies of Avista's Petition for an order authorizing deferred accounting treatment for certain power costs related to the recent dramatic increase in short-term wholesale market prices. As the Company explains in the Petition, the short-term market prices have risen to unprecedented levels. These prices have caused a comparable dramatic increase in power supply expenses for the Company.

The costs at issue in this Petition are independent of the costs for which the Company has filed for recovery in its pending General Rate Case, Docket No. UE-991606. The power costs in the General Rate Case are generally based on "normal" conditions, including normal weather, streamflow, and other operating conditions. The costs for which the Company is seeking deferred accounting treatment in this Petition are the extraordinary power supply costs related to the current unprecedented wholesale market prices.

The Company filed a Form 8-K with the Securities and Exchange Commission, dated June 21, 2000, regarding the total impacts on the Company from the increase in market prices. Irrespective of the total impacts on the Company discussed in that document, the costs at issue in this Petition are related <u>solely to the increased costs to serve the Company's customers</u>. <u>This Petition does not seek to recover losses associated with wholesale trading transactions</u>. Those trading transactions are unrelated to the Company's load requirements, and the Company has not requested deferred accounting treatment related to those costs.

The Company is not proposing a change in retail rates in this filing. The ratemaking treatment related to these deferrals would be the subject of a future filing. The Company requests that the deferred accounting treatment become effective for power costs beginning July 1, 2000. The Company requests that the Commission rule on the Company's request for deferred accounting treatment on or before July 31, 2000, and issue its order soon thereafter.

Questions regarding this filing should be directed to Kelly Norwood at (509) 495-4267.

Sincerely,

Thomas D Dukich

Thomas D. Dukich
Manager, Rates and Tariff Administration

Enclosures
c: See attached service list

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have served the Company's Petition For an Order Regarding the Accounting Treatment of Certain Wholesale Power Costs to Serve Firm Load Obligations by mailing a copy thereof, postage prepaid to the following:

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Dated at Spokane, Washington this 22nd day of June 2000.

Jean T. Osterberg
Rates Coordinator

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of the Petition of AVISTA CORPORATION For an Order Regarding the Accounting Treatment of Certain Wholesale Power Costs to Serve Firm Load Obligations	)	DOCKET NO. UE-000972 PETITION OF AVISTA CORPORATION

I. PETITIONER

1 In accordance with WAC 480-09-420, the name and address of Petitioner, Avista Corporation ("Avista Corp." "Avista," or "Company"), is as shown below. Please direct all correspondence related to this Petition as follows:

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II. INTRODUCTION

2 Pursuant to WAC 480-09-420 (7) Avista Corp. hereby requests that the Commission issue an order authorizing the deferral of certain power costs related to the recent dramatic increase in short-term wholesale market prices. As the Company will explain in this Petition, short-term market prices have risen to unprecedented levels and have caused a comparable dramatic increase in power supply expenses for the Company.

3 It has been the practice of the Commission to provide deferred accounting treatment and rate recovery for costs that are considered to be extraordinary, abnormal, unusual, or unpredictable and highly variable. The costs at issue in this Petition would qualify under all of these terms. The Company is not requesting an immediate surcharge or change in rates in

this filing. The Company requests an accounting order authorizing it to defer the increased expenses as a regulatory asset to consider for later recovery. The ratemaking treatment related to these deferrals would be the subject of a future filing.

III. SUMMARY

4 Through this Petition, the Company is requesting the Commission to authorize deferred accounting treatment for increased power costs, for the period July 1, 2000 through June 30, 2001, related to the recent dramatic increase in short-term market prices. A summary of the information in support of the Company's Petition is as follows:

5 **Dramatic Increase in Short-Term Market Prices**

- Historical monthly market prices for the last 15 years have ranged from a low of 0.8¢/KWH to a high of 4.0¢/KWH.
- Current monthly market prices are as high as 13.0¢/KWH. Daily prices have reached 37.5¢/KWH and hourly prices have frequently risen to 75.0¢/KWH.
- Kaiser announced on June 14th that because of "unprecedented electricity costs" its Tacoma aluminum smelter would be shut down, production at the Mead smelter in Spokane would be reduced, and over 400 workers laid off.
- On June 5th, Vanalco, an aluminum smelter in Vancouver, Washington, announced that it was shutting down most of its production and laying off 450 – 600 workers because of the high-cost energy market.

6 **Impact on Avista**

- Avista relies on purchases from the short-term energy market for a portion of its resource portfolio to serve its load obligations. This exposes the Company to extraordinary power supply costs related to the unprecedented rise in short-term market prices. If the Company has no way to recover these extraordinary power costs, then it must acquire more long-term firm resources, and reduce or eliminate the reliance on short-term resources.
- Based on current short-term market prices for July through December of this year, the estimated impact on the Company for the balance of this year, related to the high market prices, is an increase in costs of approximately $29 million on a system basis ($20 million for the Washington jurisdiction). A $29 million increase in costs to the Company would equal an adverse earnings impact to the Company of approximately $0.40 per common share. This represents a significant impact to the utility when compared with total earnings for the utility in 1999 of $1.00/share, and $0.88/share in 1998.
- Attached as Appendix 8 to this filing is a copy of the Company's Form 8-K filed with the Securities and Exchange Commission regarding the impacts on the Company from the increase in market prices. Irrespective of the total impacts on the Company discussed in that document, the costs at issue in this Petition are related <u>solely to the increased costs to serve the Company's customers</u>. <u>This Petition does not seek to</u>

recover losses associated with wholesale trading transactions. Those trading transactions are unrelated to the Company's load requirements, and the Company has not requested deferred accounting treatment related to those costs.

- Notwithstanding the unprecedented rise in short-term market prices, the Company takes seriously its commitment to provide safe, reliable service to its customers. There have been no curtailments of service, nor is there expected to be future curtailments, resulting from this extraordinary event.

7 **Basis for the Company's Request for Deferred Accounting Treatment**

- Historically the Commission has authorized deferred accounting treatment and rate recovery for costs that are considered to be extraordinary, abnormal, unusual, or unpredictable and highly variable.
- Examples include purchased gas costs (PGAs), storm damage, environmental remediation costs, and abnormal power costs.
- Recovery is provided in other jurisdictions through tracking mechanisms, such as Avista's Power Cost Adjustment (PCA) in the Idaho jurisdiction.
- Some other utilities are not exposed to these extraordinary changes in power costs because of electric industry restructuring or deregulation, in that the utilities are not responsible for power acquisition in those instances.

8 **Accounting for the Deferrals**

- The Company requests authorization for deferred accounting treatment to become effective for power costs beginning July 1, 2000 and ending June 30, 2001. The first deferral would occur in August 2000 for power costs incurred during the month of July 2000.
- The Company proposes that the balance of deferred costs resulting from this Petition be amortized over a ten-year period beginning July 1, 2001, with a carrying charge, equal to the Company's authorized rate of return, on the unamortized balance. If deferrals were to total $20 million for the Washington jurisdiction, the estimated future rate impact related to a 10-year amortization of this balance would be an increase of approximately 1.0 to 1.5 percent.
- If the Commission approves the Company's request for a Power Cost Adjustment (PCA) mechanism in its General Rate Case proceeding, Docket No. UE-991606, the Company proposes that the monthly deferrals under this Petition end on the effective date of the PCA. The Company proposes that the balance of costs deferred under this Petition be rolled into the PCA mechanism for ratemaking purposes. If deferrals were to total $20 million for the Washington jurisdiction, and the balance were to be rolled into the PCA mechanism, the estimated future rate impact would be an approximate five percent (5%) increase for a one-year period. The 5% would be reduced to approximately 2.5% for the second year, and then reduced to zero. If the Commission determines, that the ratemaking treatment for these extraordinary power costs should not be included in the PCA mechanism, the Company proposes that the costs be amortized over a ten-year period as explained above.

- The rate recovery of these deferrals would be the subject of a future rate filing. It is understood that the burden of proof for the reasonableness of these costs in future proceedings rests with the Company.

9 **Periodic Reporting**

- The Company proposes to provide reports to the Commission on a monthly basis related to the deferrals. The reports would include all calculations and accounting entries.

10 **Calculation of Costs for Deferral**

- The specific power costs included for deferral purposes would be limited to three power cost variables, including short-term market prices, thermal generation, and hydroelectric generation. As will be explained in this Petition, including the changes in thermal generation in the deferrals will serve to offset a portion of the total costs that would otherwise be deferred. The level of hydroelectric generation on the Company's system can also provide an offset to short-term market price impacts, and it is appropriate to include for deferral purposes.
- Deferred costs would be based on the difference between the actual costs associated with these three power cost variables, and what those costs would otherwise have been under normalized conditions.
- In the Company's General Rate Case, in Docket No.UE-991606, the Company filed information supporting normalized power supply costs for the period July 1, 2000 through June 30, 2001. At the conclusion of the case the Commission will ultimately adopt a normalized level of power costs for that 12-month period. The Company is proposing in this Petition that monthly deferrals be based on the difference between actual power costs and that normalized level. Until that case is concluded, deferrals would be based on the normalized level filed by the Company in that case. Following the issuance of the order in that case, the deferrals beginning in July 2000 would be adjusted to reflect the normalized level approved by the Commission in the General Case.
- Monthly deferrals would reflect the Company's energy surpluses and deficiencies during both heavy-load and light-load hours, and the corresponding actual heavy-load and light-load short-term market prices experienced by the Company.

11 **Avista's Request**

- The Company requests that the Commission rule on the Company's request for deferred accounting treatment on or before July 31, 2000, and issue its order soon thereafter.
- The Company requests that the deferred accounting treatment become effective for power costs beginning July 1, 2000. The first deferral would occur in August 2000 for power costs incurred during the month of July 2000.

IV. DRAMATIC INCREASE IN SHORT-TERM MARKET PRICES

A. Unprecedented Prices

12 During the past six weeks short-term market prices in the Pacific Northwest, where Avista purchases energy, have risen dramatically to unprecedented levels. Real-time prices (next hour) have frequently hit 75.0¢ per kilowatt-hour (KWH). Pre-schedule prices (next day) have risen to over 37.5¢ per KWH, and forward monthly prices (next month and longer) have risen as high as 13.0¢ per KWH.

13 To put these prices in perspective, the average monthly prices experienced by Avista from 1996 through 1999 ranged from 0.8¢ per KWH to 3.7¢ per KWH. These prices are summarized in the following table, and are also expressed in dollars per megawatt-hour (MWH):

	¢/KWH	$/MWH
1996-1999 Monthly High Price	3.7¢	$37
Current Monthly High Price	13.0¢	$130
Current Daily High Price	37.5¢	$375
Current Hourly High Price	75.0¢	$750

14 A short-term aberration (a few days or weeks) in the market prices generally would not occasion a request for deferred treatment of power supply expenses. The persistence of the current extreme high prices, however, have caused, and will continue to cause, an extraordinary increase in the Company's power costs.

15 Others in the region have also been impacted by the high market prices. For example, on Wednesday, June 14, 2000, Kaiser announced that its Tacoma aluminum smelter would be shut down, production at the Mead smelter in Spokane would be reduced, and over 400 workers laid off because of high electricity prices. Pete Forsyth, Kaiser Vice President, was quoted in a Spokesman Review article stating that "unprecedented electricity costs made the curtailment unavoidable." Mr. Forsyth also stated that the potlines at the Tacoma smelter "have never been completely idled before." A copy of the Spokesman Review article is attached to this Petition as Appendix 1.

16 A week earlier, Vanalco, an aluminum smelter in Vancouver, Washington, announced that it was shutting down most of its production and laying off 450 – 600 workers because of

the high-cost energy market. The shutdown is the first since Vanalco purchased the smelter from Alcoa in June 1987. A copy of the article in the June 12, 2000 issue of *Clearing Up* related to this shutdown is attached as Appendix 2.

17 In the southern portion of the Western Systems Coordinating Council (WSCC) area, Pacific Gas and Electric (PG&E) issued a press release, on June 14, 2000, stating that "The California Independent System Operator (CAISO) has initiated localized electric curtailments in the Bay Area due to record-breaking temperatures and the unavailability of generation." PG&E implemented rotating "block" outages of approximately 35,000 retail customers at a time in order to meet CAISO's need for energy. These curtailments of retail load were in addition to the curtailment of interruptible loads. Copies of press releases related to these curtailments are attached as Appendix 3.

B. Historical and Current Market Prices

18 A review of historical short-term market prices on an annual basis, monthly basis, as well as on a day-to-day basis shows that prices have been trending upward, and there has been a dramatic increase in volatility of the prices.

19 **Annual Prices:** Appendix 4 includes a bar chart showing the Company's average annual short-term purchase prices for 1996 through 1999. These prices start at 1.27¢ per KWH in 1996 and increase steadily to 2.75¢ per KWH in 1999.

20 **Monthly Prices:** Page 1 of Appendix 5 includes a graph of the historical monthly short-term market prices experienced by the Company for the four-year period 1996 through 1999. The prices ranged from 0.8¢ per KWH in March 1996 to a high of 3.7¢ per KWH in October 1999.

21 Page 2 of Appendix 5 illustrates the recent dramatic rise in the monthly market prices. This chart shows that the market price of power on April 19, 2000 for power to be delivered during the month of July 2000 was 4.95¢ per KWH. The price on June 12, 2000 for the same power to be delivered in July was 12.20¢ per KWH. Monthly market prices for the remainder of the year have increased significantly, as can be seen in the chart.

22 Page 3 of Appendix 5 includes a chart that contains both the 1996-1999 historical monthly prices from Page 1 of Appendix 5, as well as the forward monthly market prices from

Page 2. This chart shows that the current market prices are well above any experienced by the Company in recent history.[1]

23 **Daily Prices**: Daily market prices have increased even more dramatically. Pages 1 through 3 of Appendix 6 include graphs showing the daily heavy load and light load prescheduled electric prices at the Mid-Columbia for 1998, 1999, and year-to-date 2000. Page 3 shows a sharp increase in prices for this year, and a significant increase in volatility. Prices for a daily block of on-peak power have exceeded 37.5¢ per KWH. Recent real-time pricing has also been very volatile. Real-time prices at the Mid-Columbia during both May and June 2000 have frequently risen to 75.0¢ per KWH.

24 As will be explained later, the Company relies on short-term purchases for a portion of its portfolio to serve load requirements. As we continue to move forward in time through the remaining months of this year, the Company must either purchase at the monthly market prices and/or wait until the month arrives and purchase power on a daily basis at the daily market prices. Purchases at these higher prices have caused, and will continue to cause, an extraordinary increase in the Company's power costs.

C. Changes in Wholesale Market Conditions

25 In the years prior to the adoption of market-based pricing by the Federal Energy Regulatory Commission (FERC), the price of short-term wholesale power was capped at the cost of providing such power. Following the adoption of market-based pricing, the price of short-term wholesale power was still driven, in large part, by the cost of producing the power, and by what some have referred to as the "fundamentals" of the market place.

26 These "fundamentals" included factors such as the availability of hydroelectric generation, the availability of major thermal generation, available transmission, temperature conditions and the resulting retail loads, and the price of coal, natural gas and oil to fire generating units.

27 A combination of these factors that resulted in a shortage of energy generally caused the market price of power to move upward to the highest-cost incremental resource to serve the last kilowatt-hour that was needed. Conversely, a combination that resulted in a surplus

[1] A review of monthly market prices for the 15-year period 1985 to 1999 shows a range from 0.8¢/KWH to 4.0¢/KWH. None of them are comparable to the prices currently being experienced by the Company.

of power caused the market price of power to fall to the price necessary to displace or shut down the thermal resources that were surplus to the load requirements.

28 It is clear from the current wholesale market prices that these "fundamentals" are no longer the primary force in driving the price of power. The market price of short-term power has diverged considerably from the cost to generate the power. Market prices of 37.5¢ to 75.0¢ per KWH are well above the cost of any thermal generating unit to produce power. Recently the Mid-Columbia market prices have occasionally traded above the price at the California-Oregon Border (COB) and the market price in California. This is a very unusual event.

29 Although it is difficult to know precisely what is driving market prices at any given time, there are a number of observations that can be made. The Pacific Northwest is at or near load/resource balance. From a cost-based standpoint, the current supply and demand equation is resulting in higher short-term prices based on running higher incremental cost resources. This creates a higher floor for the price of short-term power than if the Region were in a surplus condition, separate and apart from other market forces.

30 Additional constraints on hydroelectric operations have reduced available energy for the Region, which contributes to increased volatility. For example, in recent weeks over 50% of the inflow at the Priest Rapids Hydroelectric Project on the Columbia River was being spilled past available turbines for fish enhancement. This occurred with market prices over 20¢ per KWH.

31 Liquidity, or the volume of transactions, at the major trading points such as the Mid-Columbia and COB is down considerably for short-term firm energy. This contributes to increased volatility.

32 Furthermore, restructuring at both the wholesale and retail level appears to have created some perverse market pricing. For example, a cap of 75.0¢ per KWH has been placed on the price that the CAISO will pay for power. Under tight supply/demand conditions, the price tends to move immediately to the cap of 75.0¢ per KWH, irrespective of the cost to provide the energy.

33 Events in any part of the WSCC (Northwest, Canadian, and Southwest) such as cold weather, hot weather, thermal outages, streamflow conditions, etc., can drive a change in short-term market prices for the Company. This is evident in the recent hot weather in California

that resulted in curtailment of loads, and market prices in both California and the Pacific Northwest of 75.0¢ per KWH.

34 Attached as Appendix 7 is an article from the June 19, 2000 issue of *Clearing Up* that includes a discussion of the unprecedented nature of the rise in short-term market prices. Statements in the article regarding market prices include the following: "We are at unprecedented price levels," "no one expected this volatility," "You do not see normal markets swing by a huge order of magnitude like this," "These short-term extremes are beyond what anyone imagined could happen," and "there is no longer any underlying rationale to the fundamentals."

V. IMPACT ON THE COMPANY

35 It is important to note at the outset that the costs at issue in this Petition are independent of the costs for which the Company has filed for recovery in its pending General Rate Case, Docket No. UE-991606. The power costs in the General Rate Case are based on "normal" conditions, including weather-normalized retail loads, normal streamflow conditions, normal thermal operating conditions, and normal wholesale market conditions.

36 The costs for which the Company is seeking deferred accounting treatment in this Petition are the extraordinary power supply costs related to the current unprecedented wholesale market prices. In fact, the Company's request in this filing is to defer the extraordinary costs that exceed the normalized power supply costs that will ultimately be authorized by the Commission in the General Case. Therefore, the costs relative to this Petition are in no way duplicative of the costs included in the General Case.

37 Furthermore, attached as Appendix 8 is a copy of the Company's Form 8-K filed with the Securities and Exchange Commission regarding the impacts on the Company from the increase in market prices. Irrespective of the total impacts on the Company discussed in that document, the costs at issue in this Petition are related <u>solely to the increased costs to serve the Company's customers</u>. <u>This Petition does not seek to recover losses associated with wholesale trading transactions</u>. Those trading transactions are unrelated to the Company's load requirements, and the Company has not requested deferred accounting treatment related to those costs.

38 Notwithstanding the unprecedented rise in short-term market prices, the Company takes seriously its commitment to provide safe, reliable service to its customers. There have been no curtailments of service, nor is there expected to be future curtailments, resulting from this extraordinary event.

39 With regard to the specific cost impacts on the Company related to serving the Company's system load requirements, Avista relies on the short-term energy market for a portion of its resource portfolio to serve its load obligations. The Company discussed the use of a combination of both long-term and short-term resources in its 1997 Electric Integrated Resource Plan filed with the Commission.[2] Relying on purchases from the short-term market for a portion of its resource portfolio exposes the Company to extraordinary power supply costs related to this unprecedented rise in short-term market prices.

40 If the Company has no way to recover these extraordinary power costs, then it must acquire more long-term firm resources, and reduce or eliminate the reliance on short-term resources. It is both reasonable and appropriate for the Commission to authorize deferred accounting treatment for the extraordinary costs associated with the short-term resource portfolio.

41 For the period July 2000 through June 2001 the Company has energy surpluses and deficiencies on its system as shown in Column (a) of Table 1 below. These surpluses and deficiencies represent the net difference each month between long-term firm resources and long-term firm load obligations. The Company relies on short-term market purchases to meet the deficiencies, and sells the surpluses in the short-term market.

42 These figures were developed under normal streamflow and wholesale market conditions, and reflect the net condition for the Company for the respective month. That is, within some months the Company will be both purchasing and selling short-term energy. The figures shown in Column (a) reflect the balance for the month after netting the purchases and sales together.

43 The Company's normalized retail load for the same period is shown in Column (b), and the short-term surpluses and deficiencies as a percentage of retail load is shown in Column (c).[3]

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[2] Pages 2 and 78 of the Appendices.

[3] The surpluses and deficiencies as well as the retail loads in Table 1 are the retail loads and firm contract rights and

TABLE 1

Month	Short-Term Surplus/ (Deficiency) Average Megawatts	Retail Load Average Megawatts	% of Retail Load
	(a)	(b)	(c)
July 2000	(102)	941	(10.8%)
August 2000	(152)	955	(15.9%)
September 2000	(153)	903	(16.9%)
October 2000	(113)	894	(12.6%)
November 2000	(71)	1,025	(6.9%)
December 2000	(105)	1,177	(8.9%)
January 2001	(107)	1,144	(9.3%)
February 2001	(50)	1,083	(4.7%)
March 2001	(117)	1,004	(11.7%)
April 2001	(203)	950	(21.4%)
May 2001	120	893	13.4%
June 2001	(21)	944	(2.2%)
Average	(90)	993	(9.0%)

44 These calculations show that for the next twelve-month period, the Company will rely on purchases from the short-term market averaging 90 AMW, which is equal to 9.0% of the Company's retail load. The short-term purchases vary for each of the months as shown in the table, and the Company is surplus in the month of May 2001.

45 Based on current short-term market prices for July through December of this year, the estimated impact on the Company for the balance of this year, related to the high market prices, is an increase in costs of approximately $29 million on a system basis ($20 million for the Washington jurisdiction). A $29 million increase in costs to the Company would equal an earnings impact to the Company of approximately $0.40 per common share. This represents a significant impact to the utility when compared with total earnings for the utility in 1999 of $1.00/share, and $0.88/share in 1998.[4]

obligations filed by the Company in Docket No. UE-991606. These figures exclude generation from the Centralia Project, and include the replacement purchase from TransAlta.

[4] Estimates for May and June of 2000 show a combined increase in power costs of approximately $3 million on a system basis related to serving customers' loads. The Company is not requesting deferred accounting treatment in this Petition for these months.

46 This estimate is provided for informational purposes only. The actual costs to be deferred would be based on the actual market conditions experienced by the Company. This estimate, as well as the Company's proposed deferral calculation, will be further explained later in this Petition under the heading "Calculation of Costs for Deferral."

47 The Company's proposal in this Petition is for deferred accounting treatment for the 12-month period July 1, 2000 through June 30, 2001. The Company is requesting accounting treatment for a 12-month period in order to capture the seasonal impacts that can occur over the course of a full year. For example, if the high power prices persist and the Company has surplus power in the spring of next year, the sales at the higher prices would mitigate, to some degree, the costs that the Company will experience for the remainder of the year 2000. In addition, market conditions could change over the next year and result in reduced costs to the Company. Therefore, deferrals over the course of the year could include reduced costs as well as increased costs.

48 In the long-term, for the period beyond June 2001, a combination of the following would address the power cost impacts related to the volatility in the wholesale market:

a. Implement a Power Cost Adjustment mechanism to track changes in costs related to market prices over time. This mechanism would be similar to the PGA in the natural gas industry, and similar to the Company's electric Power Cost Adjustment (PCA) mechanism that has been in place in the Idaho jurisdiction for the past twelve years.

b. The Company could acquire more long-term firm supply-side and demand-side resources and reduce reliance on short-term market purchases to serve load obligations.

49 However, the Company is not requesting a ruling in this current filing related to these longer-term solutions.

VI. BASIS FOR THE COMPANY'S REQUEST FOR DEFERRED ACCOUNTING TREATMENT

50 The Company's request for deferred accounting treatment is consistent with existing and historical ratemaking practices. The Commission has the authority to authorize the deferral of costs at issue in this filing and, in fact, has previously authorized deferred

accounting treatment for costs that were determined to be extraordinary, unusual, abnormal, or unpredictable and highly variable.

51 The Company's request is fully consistent with its pending General Rate Case, which generally addresses recovery of costs on a normalized basis. This Petition addresses costs which are extraordinary, unusual and beyond those that are included in a General Rate Case on a normalized basis.

52 Some examples of prior authorizations of deferred accounting treatment and rate recovery are as follows:

53 **Deferred Accounting for Storm Damage Costs - Docket Nos. UE-920433, UE-920499, and UE-921262.** In the Commission's Eleventh Supplemental Order, dated September 21, 1993, in the above-referenced Dockets, the Commission approved deferred accounting treatment for $16.5 million of costs for Puget Sound Energy (PSE) related to storm damage that were considered to be the result of an "extraordinary event." These costs were authorized to be amortized over a six-year period.

54 On Page 52 of that Order the Commission adopted a definition of "extraordinary events" related to storm damage. Costs related to storm events that meet this definition receive deferred accounting treatment. An excerpt of Pages 50-52 from the Commission's Eleventh Supplemental Order related to the storm damage accounting treatment is attached as Appendix 9.

55 The power costs at issue in this filing are extraordinary and unprecedented, and represent incremental costs over and above those normally incurred by the Company. Deferred accounting treatment is both reasonable and appropriate in this instance.

56 **Deferred Accounting for Natural Gas Costs of Natural Gas Distribution Utilities.** The Commission has authorized deferred accounting treatment for the natural gas costs of the natural gas distribution utilities in the State of Washington. Deferrals are made each month for the difference between the actual cost of natural gas to the utility, and the costs being collected from customers. Through periodic rate adjustments (Purchased Gas Cost Adjustments or PGAs) this difference in costs is either recovered from customers (surcharge) or returned to customers (rebate).

57 The cost of natural gas to the utility is dependent upon the market price of natural gas, which is unpredictable and highly variable. The costs at issue in this Petition, related to the wholesale market price of electricity, are also unpredictable and highly variable, as well as being extraordinary in this particular instance. Therefore, it would be reasonable and appropriate for deferred accounting treatment to be applied.

58 **Deferred Accounting for Right-of-Way Improvement Costs – Docket No. UE-980877.** In this Docket the Commission approved deferred accounting treatment for approximately $43 million of costs for PSE related to management of vegetation bordering its power line right-of-ways. These costs were authorized to be amortized over a ten-year period.

59 In its Petition, PSE stated that "the Virtual Right-of-Way Program is an extraordinary one-time program that produces long-term benefits as compared to the current on-going vegetation efforts." These costs were over and above the costs associated with PSE's traditional right-of-way tree trimming program. A copy of the Order in this Docket is attached as Appendix 10.

60 **Deferred Accounting for Environmental Remediation Costs – Docket No. UE-991796.** In this Docket the Commission approved deferred accounting treatment for PSE related to environmental remediation costs. These costs were authorized to be amortized over a five-year period.

61 The Order in Docket No. UE-991796 makes reference to a prior Order of the Commission, in Docket No. UE-911476, dated April 1, 1992, authorizing deferred accounting treatment for environmental remediation costs. On Page 4 of that Order, the Commission stated as follows:

> "The accounting treatment proposed in the Petition for remediation costs is appropriate in light of the variability and unpredictability of environmental expenditures."

62 Copies of the Orders in Docket Nos. UE-991796, and UE-911476 are attached as Appendix 11.

63 **Rate Recovery for Abnormal Power Costs. – Cause No. U-77-37** In this Docket the Commission approved a surcharge for Avista (Washington Water Power at that time) to recover increased costs associated with abnormally low streamflow conditions and high wholesale market prices. On Page 2 of the Order the Commission stated that the rate recovery was related to "specific future costs of an abnormal nature." A copy of the Commission's Second Supplemental Order in Cause No. U-77-37, dated June 9, 1977, is attached as Appendix 12.

64 Thus, it has been the practice of this Commission to provide deferred accounting treatment and rate recovery for costs that are considered to be extraordinary, abnormal, unusual, or unpredictable and highly variable. The costs at issue in this Petition would qualify under all of these terms.

65 Finally, recovery of these types of costs is provided in other jurisdictions. Many other utilities are not exposed to these costs because of tracking mechanisms or industry restructuring. In some cases restructuring or deregulation has eliminated or reduced exposure to utilities from market prices, e.g., to the extent customers take power from other energy service providers the utility is no longer responsible for power acquisition for those customers.

66 Many other utilities are not exposed to these costs because of tracking mechanisms. Avista's Power Cost Adjustment mechanism in the State of Idaho, which has been in place

for approximately twelve years, will provide recovery of the extraordinary power supply costs for that jurisdiction. The Idaho jurisdiction, however, represents only one-third of the Company's retail electric business.

VII. ACCOUNTING FOR THE DEFERRALS

67 Through this Petition, the Company requests authorization for deferred accounting treatment to become effective for power costs beginning July 1, 2000 and ending June 30, 2001. The first deferral would occur in August 2000 for power costs incurred during the month of July 2000. The Company is requesting deferred accounting treatment for a 12-month period in order to capture the seasonal impacts that can occur over the course of a full year. As explained earlier, if the high power prices persist and the Company has surplus power in the spring of next year, the sales at the higher prices could mitigate, to some degree, the costs that the Company will experience for the remainder of this year. In addition, market conditions could change over the next year and result in reduced costs to the Company. Therefore, deferrals over the course of the twelve-month period could include reduced costs as well as increased costs.

68 The Company proposes that the balance of deferred costs resulting from this Petition be amortized over a ten-year period beginning July 1, 2001, with a carrying charge equal to the Company's authorized rate of return on the unamortized balance. In the Commission's Orders in Docket Nos. UE-980877 and UE-991796, authorizing deferred accounting treatment for PSE, the Commission ordered that the unamortized balance be included in the calculation of working capital for ratemaking purposes. With regard to the deferrals related to this Petition, a carrying charge equal to the Company's authorized rate of return on the unamortized balance would provide comparable accounting treatment to the working capital allowance authorized for PSE. If deferrals were to total $20 million for the Washington jurisdiction, the estimated future rate impact related to a 10-year amortization of this balance would be an increase of approximately 1.0 to 1.5 percent.

69 The ratemaking treatment related to these deferrals would be the subject of a future rate filing. It is understood that the burden of proof for the reasonableness of these costs in future proceedings rests with the Company.

70 With regard to the selection of the ten-year amortization period, a premium is generally paid in the price for long-term firm power. That is, energy providers will charge a premium to guarantee the price of power in a long-term power contract. The reliance on short-term resources for a portion of the total resource portfolio to serve loads is supported in theory based on the presumption that over time the purchase of power at short-term market prices will better reflect the actual market price of power, and will result in lower costs to customers in the long-term. It would be reasonable to amortize these extraordinary short-term power costs over a relatively long period of time to mirror the premium that would otherwise be paid for long-term firm power. Ten years represents an amortization period that would soften the impact to customers, while providing recovery over a reasonable period of time.

71 If the Commission approves the Company's request for a Power Cost Adjustment (PCA) in its General Rate Case proceeding, Docket No. UE-991606, the Company proposes that the monthly deferrals under this Petition end on the effective date of the PCA. The Company proposes that the balance of costs deferred under this Petition be rolled into the PCA mechanism for ratemaking purposes. If deferrals were to total $20 million for the Washington jurisdiction, and the balance were to be rolled into the PCA mechanism, the estimated future rate impact would be an approximate five percent (5%) increase for a one-year period. The 5% would be reduced to approximately 2.5% for the second year, and then reduced to zero. If the Commission determines, however, that the ratemaking treatment for these extraordinary power costs should not be included in the PCA mechanism, the Company proposes that the costs be amortized over a ten-year period as explained above.

72 The monthly deferral of power costs would be accomplished by crediting Account 557 - Other Power Supply Expenses, thereby decreasing the recorded power supply expenses, and debiting Account 186 - Miscellaneous Deferred Debits. Deferred income taxes would be recorded by debiting Account 410.10 - Provision for Deferred Income Taxes and crediting Account 283 - Accumulated Deferred Income Taxes.

73 The amortization of the balance in Account 186 would be accomplished by crediting Account 186 and debiting Account 557. Deferred income taxes would be recorded by debiting Account 283 and crediting Account 411.10 – Provision for Deferred Income Taxes-Credit.

VIII. PERIODIC REPORTING

74 In the Commission's prior orders authorizing deferred accounting treatment, it has consistently required periodic reporting related to the costs being deferred. The Company proposes to provide reports to the Commission on a monthly basis related to the deferrals. The reports would include all calculations and accounting entries. The reports would be submitted by the end of the month following the month for which the deferral is made, e.g., the report related to the deferred costs for July 2000 would be provided by August 31, 2000.

IX. CALCULATION OF COSTS FOR DEFERRAL

75 The specific power costs included for deferral purposes would be limited to three power cost variables, including short-term market prices, the related changes to thermal generation, and hydroelectric generation. The Company is proposing that deferred costs be calculated as the difference between the actual costs associated with these three power cost variables, and what those costs would otherwise have been under normalized conditions.

76 In the Company's General Rate Case, in Docket No.UE-991606, the Company filed information supporting normalized power supply costs for the period July 1, 2000 through June 30, 2001. At the conclusion of the case the Commission will ultimately adopt a normalized level of power costs for that twelve-month period. The Company is proposing in this Petition that monthly deferrals be based on the difference between that normalized level, and the actual costs associated with the three power cost variables. Until that case is concluded, deferrals would be based on the normalized level filed by the Company in that case. Following the issuance of the order in that case, the deferrals beginning in July 2000 would be adjusted to reflect the normalized level approved by the Commission in the General Case.

77 With regard to power cost impacts related to thermal generation, including the changes in thermal generation in the deferral calculation will serve to <u>offset</u> a portion of the total costs that would otherwise be deferred. The Company's thermal units generally run more under high market price conditions than under "normalized" conditions. The units are run more because the incremental cost to run the units is less expensive than purchasing short-term market power, i.e., less expensive to serve load obligations. Therefore, including changes in thermal generation and thermal fuel costs in the deferral would generally result in lower cost deferrals than would otherwise occur.

78 With regard to hydroelectric generation, the level of hydroelectric generation on the Company's system can also provide an offset to short-term market price impacts, e.g., if hydroelectric conditions are above-normal at any time during the next 12 months, it would serve to partially offset the deferred costs. It would be reasonable and appropriate to include the changes in hydroelectric generation in the deferral calculation.

79 Monthly deferrals would reflect the Company's energy surpluses and deficiencies during both heavy-load and light-load hours, and the corresponding actual heavy-load and light-load short-term market prices experienced by the Company.

80 Appendix 13 includes a summary of the normalized power costs filed by the Company in Docket No. UE-991606 for the twelve-month period July 1, 2000 through June 30, 2001.

81 Appendix 14 includes a breakdown of the normalized data into heavy-load and light-load hours, and an estimate of power costs to the Company based on future short-term market prices. The estimated impact on the Company from the increase in short-term market prices is the difference between the power costs in Appendix 14, and the normalized level of power costs in Appendix 13. Again, the only changes in power cost variables reflected in this calculation would be short-term market prices, the related changes to thermal generation, and hydroelectric generation. As stated earlier, following the issuance of the Commission's Order in Docket No. UE-991606, the normalized level of power costs in Appendix 13 would be adjusted to reflect the normalized level approved by the Commission in the General Case.

82 The estimate shows an increase in power costs of $29 million on a system basis. This estimate is provided for informational purposes only. The actual costs to be deferred would be based on the actual conditions experienced by the Company for each of the respective months. Details supporting the deferral calculation would provided to the Commission each month as explained above under "Periodic Reporting."

X. COMPANY'S REQUEST

83 The Company respectfully requests that the Commission issue an order, in the form attached as Appendix 15, approving the Company's request for deferred accounting treatment for certain power supply costs as explained in this Petition. The Company requests that the Commission rule on the Company's request on or before July 31, 2000, and issue its order soon thereafter. The Company requests that the deferred accounting treatment become

effective for power costs beginning July 1, 2000 and ending June 30, 2001. The first deferral would occur in August 2000 for power costs incurred during the month of July 2000.

84 If the Commission approves the Company's request for a Power Cost Adjustment (PCA) in its General Rate Case proceeding, Docket No. UE-991606, the Company proposes that the monthly deferrals under this Petition end on the effective date of the PCA. The Company proposes that the balance of costs deferred under this Petition be rolled into the PCA mechanism for ratemaking purposes. If the Commission determines, however, that the ratemaking treatment for these extraordinary power costs should not be included in the PCA mechanism, the Company proposes that the costs be amortized over a ten-year period as explained in this Petition.

DATED this 22nd day of June 2000

By: ______________________

David J. Meyer

BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-________

APPENDIX 1

Thursday
JUNE 15, 2000 • 50 CENTS

THE SPOKESMAN-REVIEW
NEWS ONLINE: WWW.SPOKANE.NET

Power costs lead to Kaiser cutbacks

Company to idle potlines at Tacoma, Mead; 410 workers to temporarily lose jobs

By Bert Caldwell
and Hannelore Sudermann
Staff writers

Kaiser Aluminum & Chemical Corp. will close its Tacoma smelter and trim production at its Mead plant as high power costs force deep production cutbacks, the company said Wednesday.

The temporary curtailments will cost more than 400 hourly workers their jobs — 130 at Mead. All are replacements for Steelworkers who walked off the job over an unresolved labor contract on Sept. 30, 1998.

Kaiser Vice President Pete Forsyth said aluminum output at the two smelters will be reduced by almost half — from annual production of 273,000 metric tons to 145,000 metric tons.

Tacoma, with a capacity of 73,000 tons from three potlines, has been operating at 65,000 tons. All three lines will be shut down, and layoffs will affect 280 people there.

The plant's potlines, where alumina is smelted into aluminum, never have been completely idled before, Forsyth said.

The facility's rod mill will remain open.

> *"Solve the problem of the power and those jobs will come back."*
>
> **David Foster**, *chief union negotiator*

Mead has a capacity of 200,000 metric tons from eight potlines. Two-and-a-half lines producing 63,000 tons will be switched off, he said.

The Trentwood rolling mill will not be affected by the cutbacks.

Forsyth said unprecedented electricity costs made the curtailment unavoidable. In fact, he said, the company will make more money selling now-excess power than it would have earned on aluminum produced using that energy.

Prices have tripled from about $30 per megawatt-hour to $100 per megawatt-hour in recent weeks. World prices are less than $20 per megawatt-hour.

Officials say late snowmelt, efforts to refill reservoirs and electricity sales to California are contributing to the high prices.

Electricity typically constitutes about 40 percent of the cost of making aluminum. The industry's vast appetite for energy brought 10 smelters to the Northwest, where cheap hydropower energized 40 percent of the nation's aluminum production capacity.

But electricity prices have been climbing — alarmingly so, Forsyth said. "There's no rationale for current prices."

Kaiser will sell 100 megawatts of power

Continued: Kaiser/A6

Kaiser: No impact seen on labor talks

Continued from A1

the company bought from various sources. Those purchases were intended to supplement supplies from the Bonneville Power Administration.

The 340 megawatts obtained from Bonneville will sustain the remaining capacity at Mead, Forsyth said.

"That power is power we think that long term we need to continue to make aluminum in the Northwest," he said.

Kaiser's contract with Bonneville expires Sept. 30, 2001.

The federal power-marketing agency has proposed a reduction in the allotment that smelters will receive from hydroprojects in the region, but Kaiser and other smelters are pushing for more.

"We've got to get innovative," Forsyth said.

Among the possible solutions he suggested are new generating plants, the right to obtain less-expensive power through public utilities that buy from Bonneville, or access to excess power available at odd hours or when streamflows are high.

Kaiser is the second company to announce production cutbacks stemming from rising power costs.

Vanalco, based in Vancouver, Wash., shut down 75 percent of its capacity last week, costing 450 workers their jobs.

The Kaiser workers, all of whom are temporary, will receive $1,000 and one month's medical and dental benefits if they have been with the company for more than six months, spokeswoman Susan Ashe said.

Those working there more than a week but less than six months will get $250 and one month's medical and dental benefits.

"I think it's a pretty fair offer," Ashe said.

One temporary worker who has worked at Mead more than a year said Wednesday he hopes he's among the first to go.

John, a potline worker who, fearing retaliation, asked that his full name not be used, said he's ready to quit anyway. In the past two months, the company has added more duties to his job, he said, making the work too taxing.

"In the beginning it was a good job," John said. "I'm not happy now at all."

Forsyth said it will take a few days to finish tapping out the affected potlines.

Restarting them will depend on when the energy markets stabilize, he said.

Although frustrated by the volatility, he said, "We're still in the primary (aluminum) business."

News of the production cuts and job reductions came as somewhat of a surprise to the United Steelworkers of America.

But both the Mead Steelworkers and a national union official said it's not unusual for a company to close potlines when prices for power are high.

"We were down to two lines in '83," Mead Steelworker Cathy Gunderson said. "I believe it was the power cost then, too."

Some 2,900 Steelworkers are locked out of their jobs at five Kaiser plants, including Mead and Trentwood in Spokane. Wednesday's announcement came after bargaining had recessed in Pittsburgh.

The company's cutting of 410 hourly jobs won't impact labor contract negotiations, said David Foster, chief union negotiator.

"We're just as committed as we've ever been toward bringing this thing toward a just conclusion," Foster said.

"Potentially, people would be laid off until the question of power is resolved. But these are not permanent job losses," he said. "Solve the problem of the power and those jobs will come back."

Neither side would discuss details of the labor talks, though Foster described them as "moving at a snail's pace." They're scheduled to meet again the week of June 26 at a location to be determined.

Also Wednesday, Steelworkers who had temporarily disbanded their picket line at the Port of Tacoma resumed their blockade of the pier where alumina for Kaiser was being unloaded.

So far, the longshoremen hired to unload the vessel have not crossed that picket line.

BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-________

APPENDIX 2

Supply & Demand

[13] Vanalco Says BPA Exit Not Just Lower Rates; Price Run-up Questioned ■ *from [2]*

Still reeling from its June 5 announcement that high electricity rates have forced the shut-down of four of five potlines at its primary aluminum smelter in Vancouver, Vanalco Inc. last week sought to clarify impressions about why it left BPA service five years ago. Meantime, sudden and dramatic run-ups in power market prices have raised questions of whether the new California PX and ISO-based system is being gamed.

"Live by the spot market, die by the spot market," said Kevin O'Meara, senior economist at the Public Power Council. "This outcome is a result of business decisions made by Vanalco--they explicitly decided to get off BPA and follow a high-risk strategy of relying on short-term sales. Sometimes that works for you and sometimes it does not."

'The cause of the shutdown is the unforeseen disastrous rise in the plant's electricity costs over the last several weeks.'

While most of BPA's DSI customers displaced portions of their BPA load in 1996, Vanalco went to the furthest extreme, turning to other sources for 96 percent of its load. "They made a strategic decision to move off Bonneville, and did quite well initially," O'Meara said.

"There is an assertion out there that we left Bonneville because the market was less expensive than BPA, and that is just not true," said Noel Shelton of Energy Services Inc., the smelter's power manager. "As proof of my assertion that it's not true," he noted that at the time, one of the DSIs publicly announced the price of replacement power as $25.5/MWh. "So the market was greater than the IP" rate DSIs were paying under their long term BPA contracts.

Shelton said he objects to the sentiment, which he attributed to Bonneville, that "we bailed on BPA because of corporate greed; that we sowed these seeds and are now getting them back. We talked with Bonneville long and hard about modifying our 1981 contract before reducing our contract demand."

There were two main reasons Vanalco left BPA, Shelton said. Due to listings of fish under the ESA, BPA "could not provide the quality of service" or flexibility written into the DSI's contract."We were not allowed to compete in the market. Bonneville was our agent and Bonneville gave us the worst deals available; they gave us the dregs in the market," he maintained.

The second reason, he said, was that "we had a definition of stranded costs from [former BPA administrator] Peter Johnson, and the definition remained the same throughout the term. But Bonneville got worried and said 'We will impose a new stranded cost on you,' and they wouldn't define it." That was an unacceptable risk, he said, so Vanalco went to the market. "It wasn't about chasing more attractive power," he emphasized. Later, market prices fell, but "we had no way of knowing that was coming. It was a windfall." Later still, of course, market prices began to exceed BPA's cost-based rates.

Shelton said that, given the circumstances at the time, he has no regrets about the decision to leave BPA. But "given that this decision has become more significant after the fact than at the time, would I have made a different choice? Absolutely."

'Given that this decision has become more significant after the fact than at the time, would I have made a different choice? Absolutely.'

Although Vanalco said in its 1995 termination letter that its decision was triggered by BPA's disposition with respect to the stranded cost provision, Vanalco VP and general manager Charles D. Reali told *Clearing Up* at the time that leaving BPA was a business decision. He said the company felt it could do better than the IP rate BPA had proposed, and noted that alternative suppliers had already brought in lower-priced proposals, though they were not formal offers (CU No. 700 [9/20]).

In any case, Vanalco eventually decided to leave a small portion of load on BPA "to maintain a relationship with Bonneville as a supplier," and signed up with ESI to obtain all its remaining needs on a competitive basis. Shelton said that since then, Vanalco has *not* relied principally on the spot market. He said the company has employed a range of mechanisms--from fixed to indexed prices with collars or hedges. "We have purchased power using all these pricing mechanisms."

In addition, while Vanalco's contract load on BPA is minimal, the smelter has made significant purchases of surplus firm power from the agency over the past few years. "It is fair to say during part of this period, they have relied a lot on Bonneville sales," said Dennis Oster, BPA account executive.

'We have exhausted our Rolodex looking for a power supply that would leave this plant in operation.'

About 450 of the plant's 650 employees will be laid off due to the shut-down, Vanalco said in its announcement. The smelter has a total load of between 230 aMW and 235 aMW, and a smelting capacity of about 128,000 short tons per year.

"The cause of the shutdown is the unforeseen disastrous rise in the plant's electricity costs over the last several weeks," Reali said. He cited several factors, including the traditional southwest summer peak and the unusually hot weather there this year. In addition, "more and more of the electricity produced in the Northwest is being sold into California and indirectly into the Southwest, so much so that Northwest prices have begun to mirror high California prices; [also] gradual continuing deregulation in California has created an uncertain and volatile market, especially in hot weather conditions.

"We were hopeful that we could weather the market increases, which in some cases have tripled in the last few weeks, but all indications are that this market upturn will continue for some time," Reali said. Aluminum prices, meanwhile, are down. Even so, "We intend for this to be a temporary partial shutdown." But representatives of the company would not predict how long the shutdown will last, and even suggested there could be more layoffs.

"We have exhausted our Rolodex looking for a power supply that would leave this plant in operation," Shelton said. He added that Vanalco has many RFPs for power still out.

The smelter--the oldest in the region--also faces limited access to BPA IP service going forward. DSI allocations for the post-2001 period are based on the current rate period. The agency now serves only 10 aMW of Vanalco's load under the IP rate, Shelton said. Under the new allocation, the most they can buy is 6 aMW--far too little even to keep one potline open. And as a non-signatory to the BPA DSI allocation settlement, Vanalco will also be paying 1.5 mills more than DSI signatories.

The privately-held Vanalco, whose workers are not unionized, met with BPA last week to "explore what's possible," but the agency has said it won't be offering any special arrangements. Asked if Vanalco's pending litigation against BPA could be a factor in talks, Shelton said, "Perhaps. It's probably not the first time in history other considerations come into play." After the meeting, Shelton called it "very constructive" but said the litigation was not discussed.

BPA's Oster emphasized the agency is concerned about Vanalco's and the other DSI's survivability. He said BPA's Subscription Strategy "made a commitment to provide a significant amount of power" to the DSIs--1440 aMW. "We are keenly aware that the DSIs have been long-standing BPA customers, and we have adopted a strategy that delivers an appropriate level of benefits."

It is of course true that there has been a dramatic run-up in spot power prices in recent weeks. One day last week, for example, delivered prices on the Mid-C for the July through September period were in the \$80/MWh-plus range for heavy load hours and \$50/MWh for light load hours. Northwest industrial rates that are indexed to the COB hub were in the 50 mills range during May. COB prices tend to be calibrated to the California PX. According to the California ISO's *Weekly Market Watch* for the week ending May 26, "Prices surged in both the ISO real time and PX day-ahead energy markets, reaching the highest weekly averages since the California ISO began operations."

These facts may be indicators of a 'catastrophic public policy issue.'

"Ever since the California PX got started, spot prices have been way up," PPC's O'Meara noted. Some of Vanalco's contracts in the last few years have had indexed prices.

The reason for the spot market run-up is obscure. In the Northwest, the snowpack is within typical levels, although the runoff has been slower than normal. BPA last month was buying on some hours for balancing, which is unusual in May.

"We are having some strange behavior" in the spot market, said Robert McCullough of McCullough Research. California "traditionally likes command and control, and has created a mechanism in the PX and ISO that gets gamed," resulting in artificially high prices, he said. "Fundamentals have lost their influence over prices."

He noted that the NYMEX price closed at 60 mills for June, when the futures for June 2001 were at 30 mills. "If this is a relatively average year, why are futures for next year half of those for this year?" He said the correlation between fundamentals and market price always worked perfectly--until last month, "when it fell right off the scale." These facts may be indicators of a "catastrophic public policy issue," he added *[Ben Tansey]*.

BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-________

APPENDIX 3

PG&E News Releases

FOR IMMEDIATE RELEASE June 14, 2000

CONTACT: News Department (415) 973-5930

CAISO DIRECTS PACIFIC GAS AND ELECTRIC COMPANY TO IMPLEMENT ROTATING OUTAGES DUE TO RECORD-BREAKING TEMPERATURES IN BAY AREA

The California Independent System Operation (CAISO) has initiated localized electric curtailments in the Bay Area due to record-breaking temperatures and the unavailability of generation. At the direction of the CAISO, Pacific Gas and Electric Company has begun implementing rotating outages throughout the Bay Area in order to maintain electric service to customers that provide essential public safety services, such as hospitals and fire stations.

Pacific Gas and Electric Company began rotating "block" outages in order to meet the CAISO's need for 100 megawatts of relief. A block of customers is equal to approximately 35,000 customers, for 100 megawatts. If the CAISO determines that there is need for additional load shedding, Pacific Gas and Electric Company will cooperate by implementing further outages. Outages for each customer block affected will last for approximately 1-2 hours.

Each Pacific Gas and Electric Company customer's rotating outage block number is shown on their monthly bill. Rotating outage blocks are numbered from 1 through 14. Essential services, such as hospitals, fire departments, police stations, and other vital government functions will not be impacted.

Pacific Gas and Electric Company asks customers to monitor radio and television news to stay abreast of curtailment schedules, which are subject to sudden change.

Pacific Gas and Electric Company urges everyone in Bay Area cities to be very careful during times of power outages. It is possible that traffic lights will not be operating, and congestion on streets could lead to dangerous situations. Pedestrians and motorists are urged to exercise caution.

In areas where service is not being curtailed, the CAISO and Pacific Gas and Electric Company says it is important that customers discontinue all but critical electricity use. Air conditioners should be shut off, the use of washers, dryers and dishwashers postponed, all unnecessary lighting turned off, and any cooking done before noon or after 6 p.m.

Agricultural pumping should be minimized and confined to periods outside the noon to 6 p.m. peak demand time.

Pacific Gas and Electric Company thanks its customers for their cooperation during this curtailment. If customers have specific questions, they can contact the company at 1-800-PGE-5000.

The CAISO is the agency responsible for managing California's power grid. For more information on the CAISO or the electric curtailment program, please visit their website at www.caiso.com or call 1-888-516-6397.

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News Releases

FOR IMMEDIATE RELEASE June 14, 2000

CONTACT: PG&E News Department (415) 973-5930

CAISO ORDERS PG&E TO IMPLEMENT NON-FIRM INTERRUPTIBLE PROGRAM FOR BAY AREA

Record-Breaking Heat Wave and Unavailable Generation Has Prompted Call for Large Customers to Curtail Energy Use

Due to record-breaking temperatures and the unavailability of major power plants in the Bay Area, the California Independent System Operator (CAISO) has ordered Pacific Gas and Electric Company to implement its localized Non-Firm Interruptible Program in order to reduce demand on the electric grid in the Bay Area.

Pacific Gas and Electric Company's Non-Firm Interruptible Program involves several large customers who benefit from reduced energy bills in exchange for agreeing to curtail their energy use when the need arises. In the Bay Area, the program amounts to 200 megawatts. The CAISO's order applies only to customers in the Bay Area and will be in effect from noon to 6 p.m. These efforts are being taken to prevent large scale problems as a result of heat and generation concerns.

Approximately 75 Bay Area customers take part in Pacific Gas and Electric Company's Non-Firm Interruptible Program and have readily curtailed their energy usage when it has been necessary in previous times of great demand on the electric system.

The CAISO, a nonprofit corporation created when California deregulated its electric industry, manages the transmission grid for the state.

In addition to asking its non-firm customers in the Bay Area to curtail their usage, representatives from Pacific Gas and Electric Company have personally called all large customers (over 500 kilowatts) and asked them to reduce their usage by taking simple steps like dimming lights, adjusting the air conditioner to 78 degrees and turning off unnecessary office equipment.

As the state of California continues to experience high temperatures, Pacific Gas and Electric Company's residential customers are asked to help relieve the strain on the electric grid by closing drapes and blinds during the day, setting the thermostat to 78 degrees or higher, using a fan instead of an air conditioner if the weather is mild, and shifting the use of heat-producing appliances such as ovens, dishwashers, clothes dryers and irons from mid-day to early in the morning or later at night when possible.

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BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

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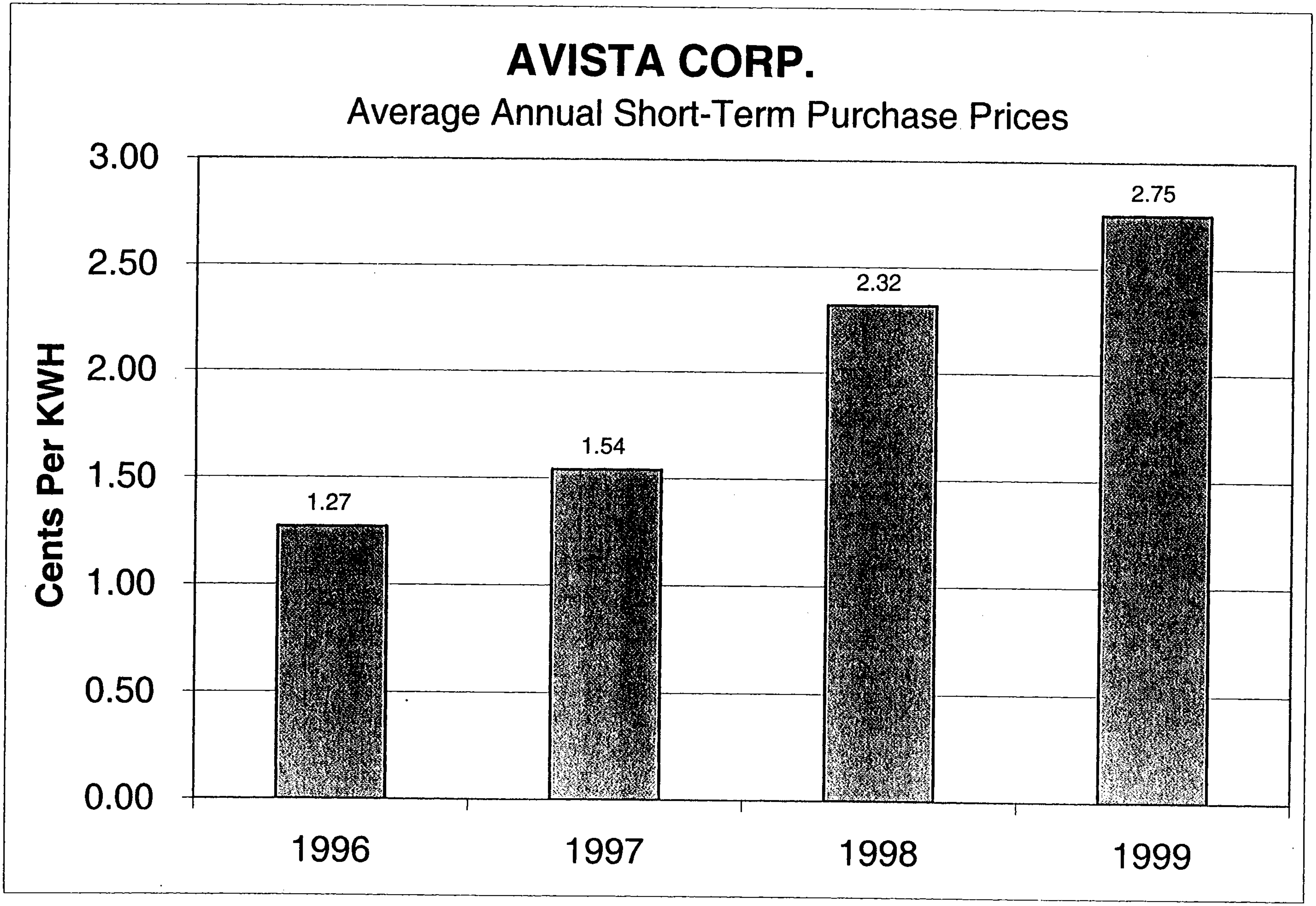
APPENDIX 4


AVISTA CORP.
Average Annual Short-Term Purchase Prices
Cents Per KWH
3.00
2.50
2.00
1.50
1.00
0.50
0.00
1.27
1.54
2.32
2.75
1996
1997
1998
1999

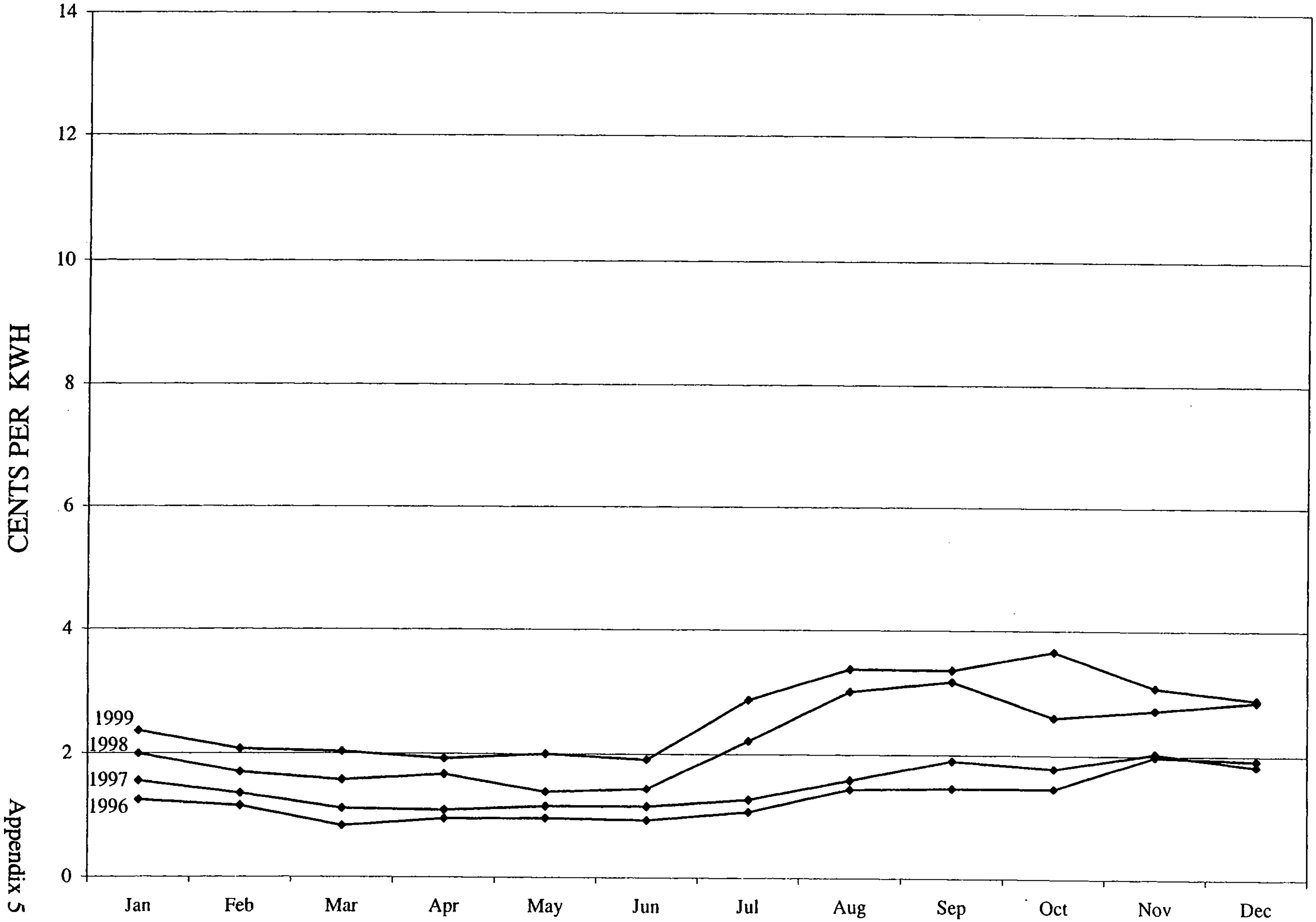
BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

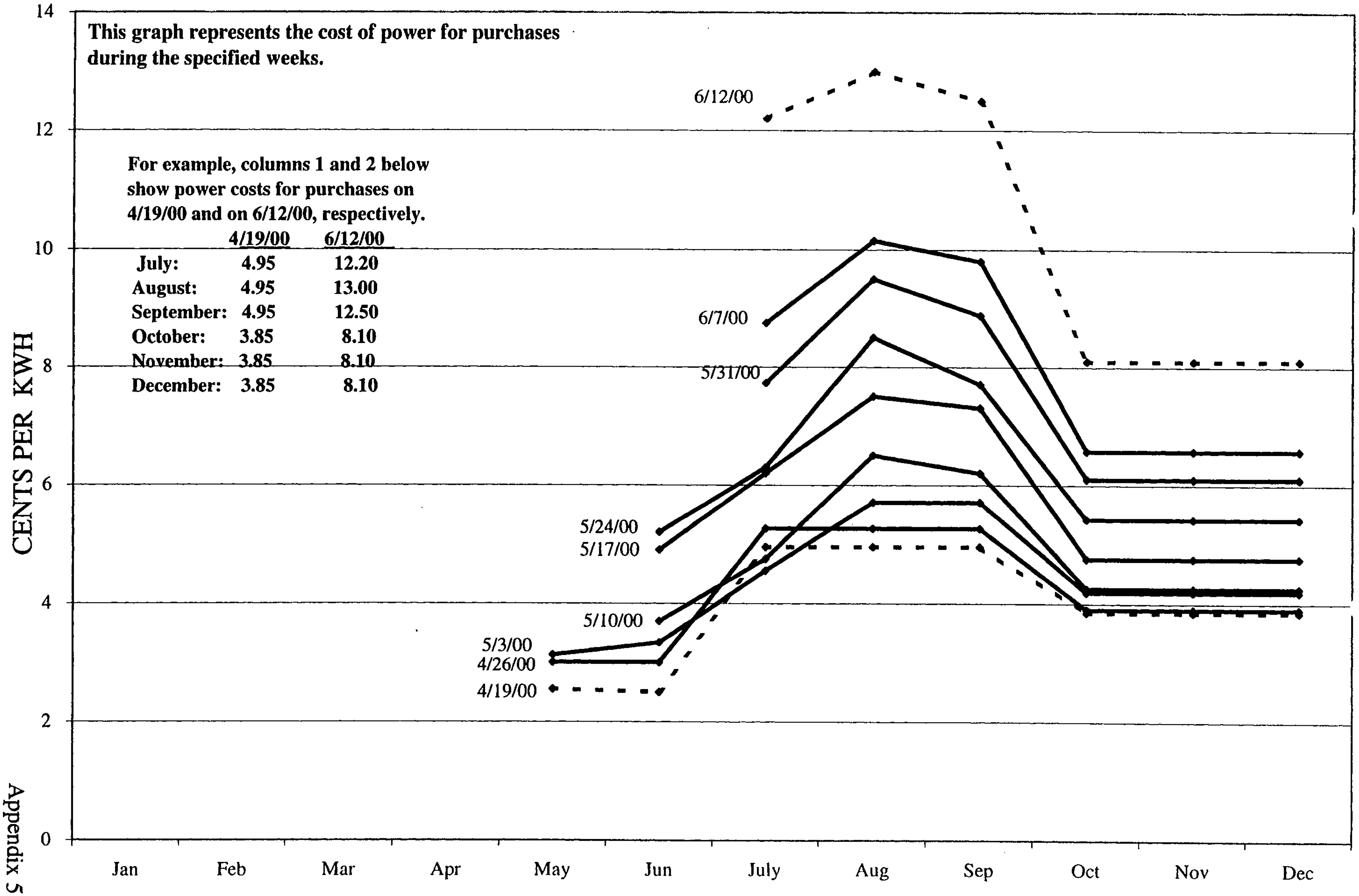
DOCKET NO. UE-________

APPENDIX 5

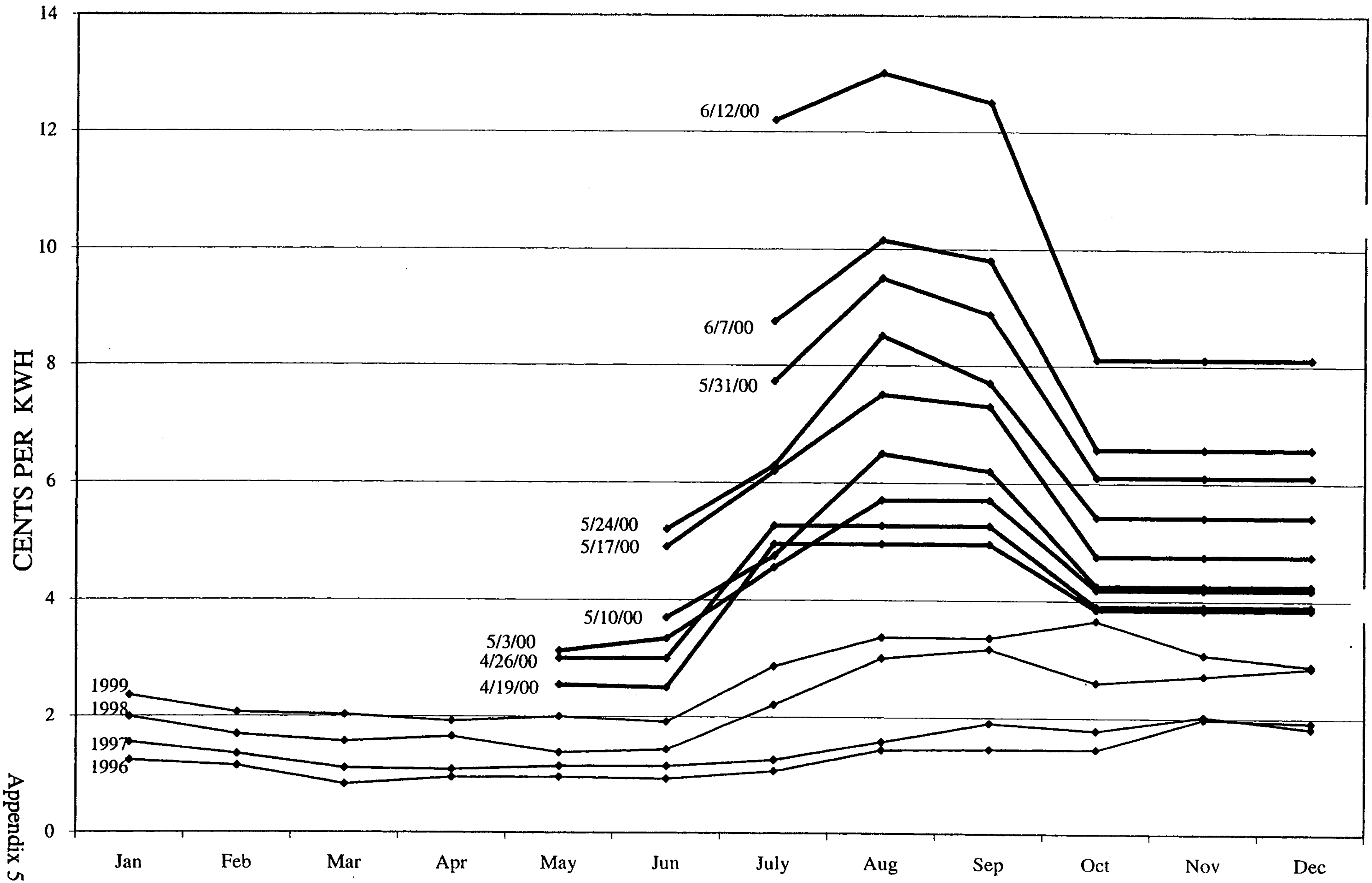
AVISTA CORP.
MONTHLY SHORT TERM MARKET PRICES 1996-1999



AVISTA CORP.
MID-COLUMBIA FORWARD PRICES



AVISTA CORP.
MID-COLUMBIA FORWARD PRICES VS HISTORICAL MARKET PRICES

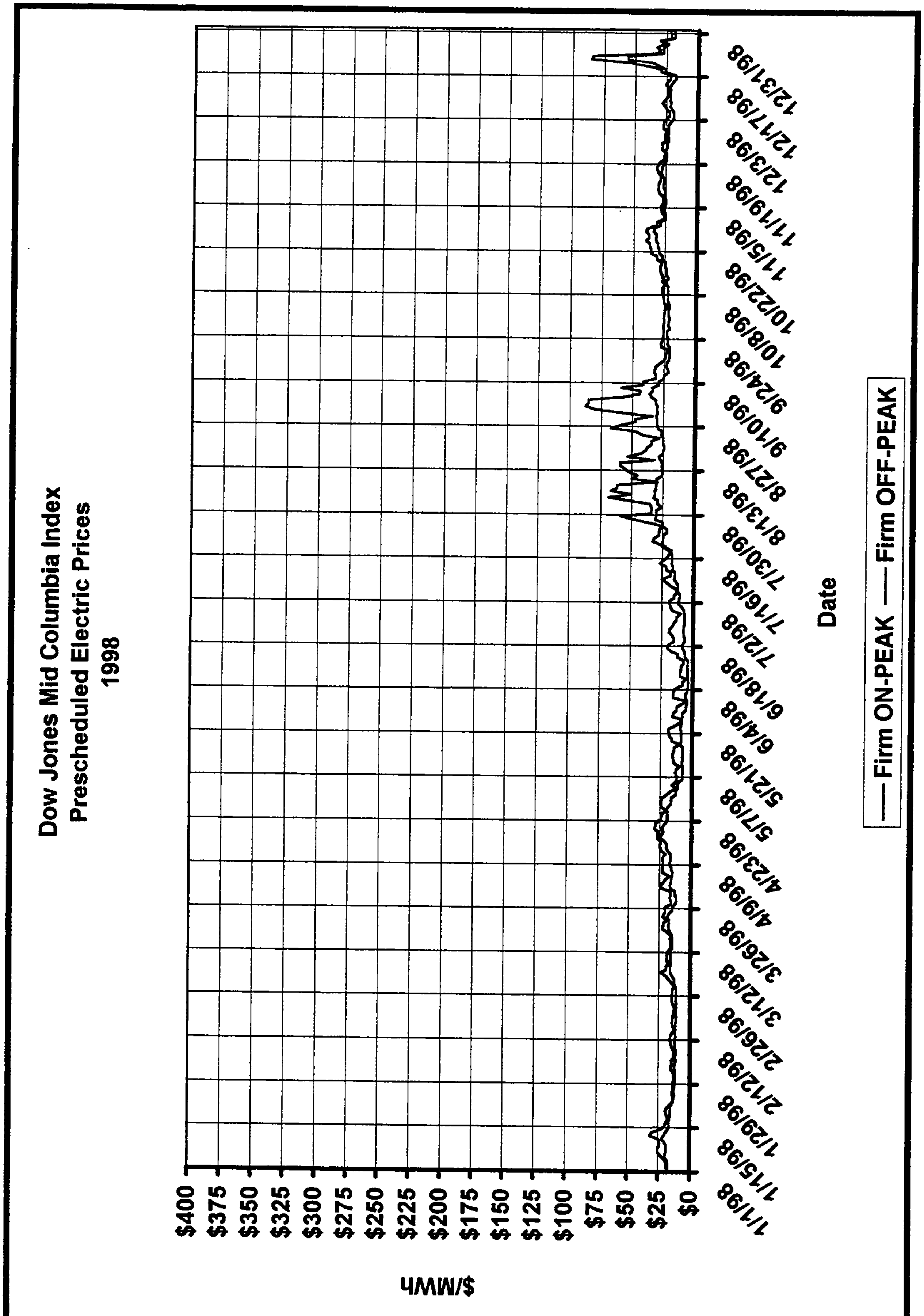


BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-________

APPENDIX 6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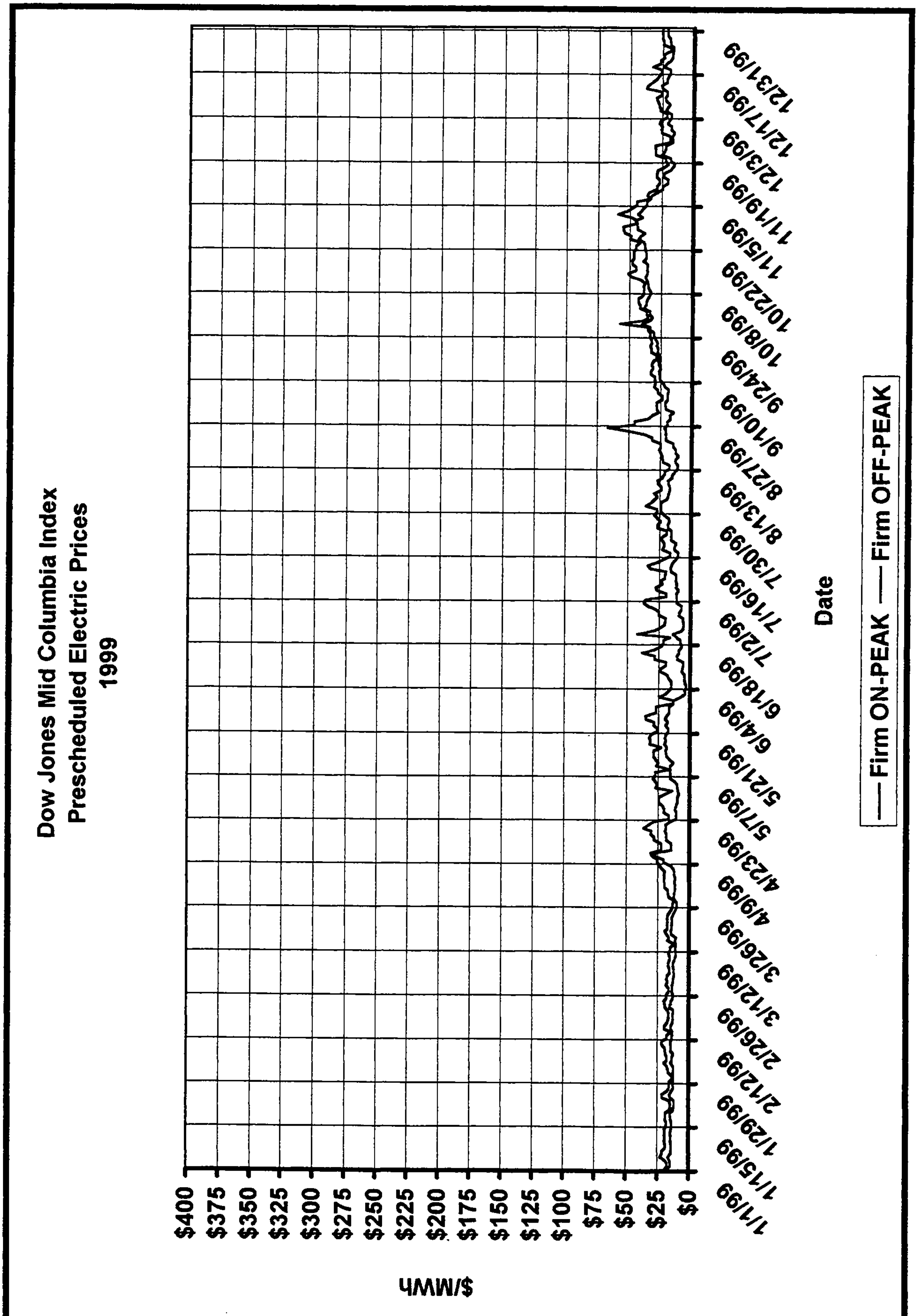
Dow Jones Mid Columbia Index
Prescheduled Electric Prices
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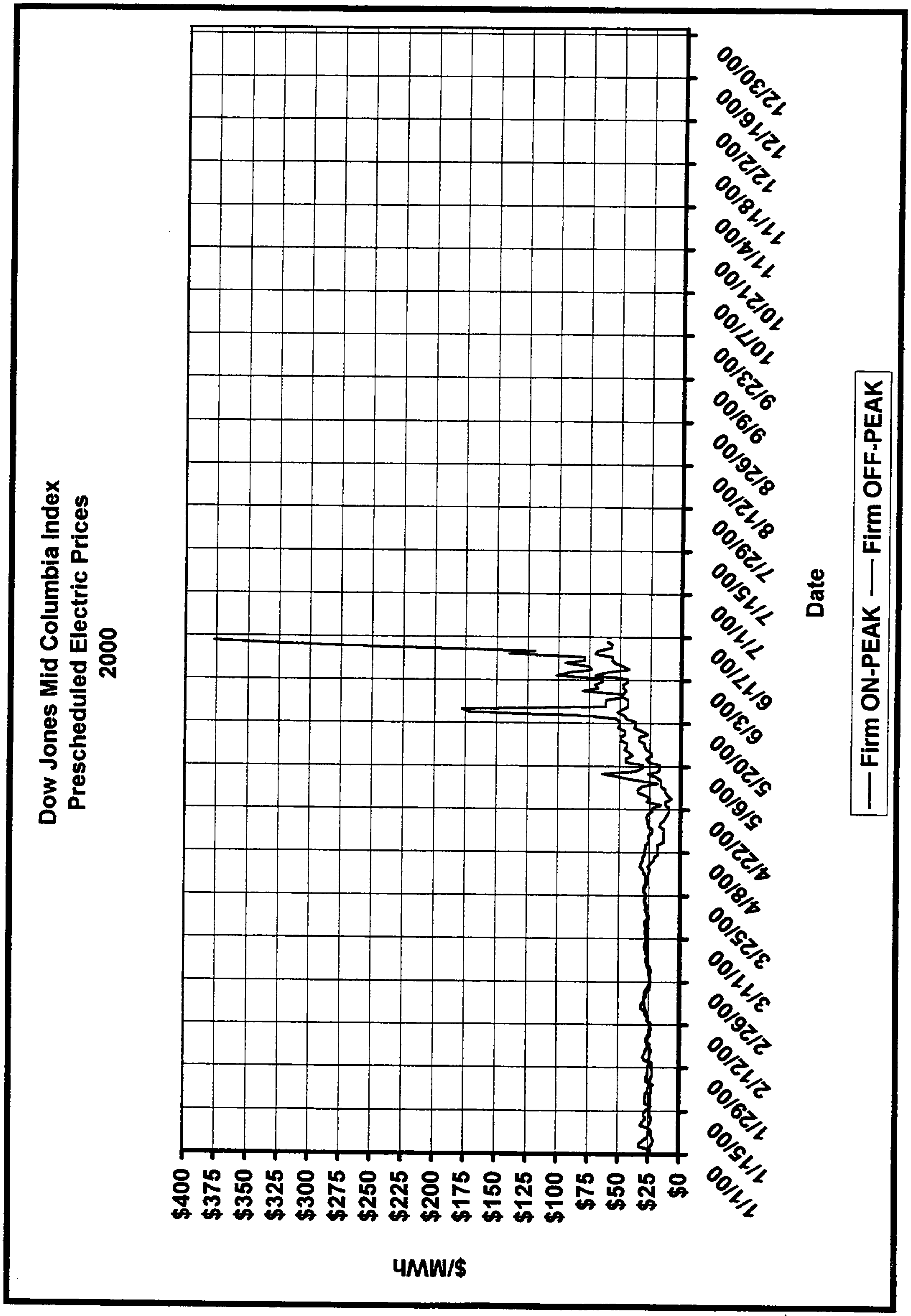
Dow Jones Mid Columbia Index
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[21] Reasons behind NW Electricity Price Run-ups Difficult to Define ■ *from [2]*

The fact that clearing prices on the California Power Exchange reached new highs of over 600 mills/KWh last week came as no big surprise to the Northwest utility community. But the fact that Northwest prices weren't all that far behind--topping 400 mills/KWh at COB and Mid-C--caught everyone's attention.

"We are at unprecedented price levels," observed Bill Gaines, PSE vice president of energy supply. "We don't want to believe it's sustainable."

There were some regional factors contributing to the price run-up. "Especially at this time of year, most of what we do is driven by fish requirements," said BPA manager of generation scheduling Bruce McKay. The agency is required to refill Grand Coulee reservoir while also meeting flow requirements under the BiOp. Upper basin run-off from Canada has, in the last few years, usually covered those dual demands. But that runoff didn't materialize in late May and early June this year--what McKay called a "real outlier" among the various possible scenarios. "This forced us into the market to purchase power to meet refill requirements," he said. So instead of being a seller as it usually is this time of year, BPA has been buying power in recent weeks.

At the same time, some thermal units have been off line, including PGE's Boardman, Centralia (now owned by Transalta), Clark Public Utilities' River Road CT, PacifiCorp's Naughton and Bridger plants and Colstrip Unit 4. Some of those outages were planned and were over by last Thursday--including Centralia and River Road. But others were apparently unplanned. Still, Northwest utility loads were normal for this time of year, so these unit outages alone can't be blamed for last week's soaring spot market prices.

"Several people have been saying that this could happen," observed BPA senior risk analyst Carl Buskuhl. "Since 1996 we've had an opportunity to see what prices have done relative to water levels." The last several years have been good water years, he pointed out, while this year is closer to average; "prices are much more volatile in good water years."

'We don't want to believe it's sustainable.'

Buskuhl also believes the market is now much bigger than just the Pacific Northwest: "demand in other parts of the country influences it."

Especially California. "If prices spike to 750 [mills/KWh] at the Cal ISO, it's not too surprising to see prices here going up," said BPA's McKay. "California is setting the tone for the rest of the markets in the West," agreed Powerex president Ken Peterson. "We first noticed it the last week of May," said PSE's Gaines, when California experienced its first heat wave and thermal plants were out on maintenance. "We seem to have a repeat," he said of last week's California emergency, "but that doesn't explain the long-term markets being as high as they are."

Gaines thinks another contributing factor is consistently high prices for natural gas. With additional pipeline capacity coming on line in Canada, gas that was once captive to the Northwest market can be sent to the Midwest instead, increasing demand for the same supply.

But in spite of the high gas prices, PSE is operating all of its combustion turbines, Gaines said; the price of electricity is still higher than the price of natural gas. PSE's units have been running since late May; usually they don't start up until mid-summer to generate power for sales into California.

Power has definitely been flowing south. WSCC executive director Dennis Eyre said the AC and DC Interties were close to their limits early last week. But by Thursday, the AC line was at 3440 MW of its derated 3950 MW limit, while the DC line was at 2474 MW of its 2940 MW limit. "Capacity is available," he said, but "I don't know what the price signal is."

"Someone is buying at those high prices. Not us," said Young Linn, a trader on BPA's PBL trading floor. "We are not supporting these high prices, but are buying to the extent things are economic for us."

Powerex is among those selling at the high prices, said president Ken Peterson. "A lot is going to California for replacement reserves," he said. "It drove our receipts way up" he told *Clearing Up*. But Peterson also said Powerex is "constantly fighting constraints on the interties."

The high Northwest power prices are causing big headaches among the region's industrial customers. "It's real tough on those who are on indexed pricing," said Ken Canon, executive director of Industrial Customers of Northwest Utilities. "I would not be surprised to see some potential shut-downs because of it."

Perhaps ironically, the region's industrial customers have for years pushed for the opportunity to purchase power at market rates. But Canon pointed out that most market-rate tariffs provide power at costs indexed to the market, rather than allowing customers direct access. "With indexed pricing you have less flexibility," he said; with direct access, the industrials could decide for themselves whether it makes sense to buy power at the going price.

'You do not see normal markets swing by a huge order of magnitude like this.'

"The industry has always understood there would be some variability [with market-based prices]," he added, "but no one expected this volatility." Canon also questioned whether recent prices reflect a real competitive market. "You do not see normal markets swing by a huge order of magnitude like this." Last year, prices at this time were around 30 mills/KWh; now, they are hitting the 750 mills/KWh cap set in California. "These short-term extremes are beyond what anyone imagined could happen," he added.

"It's a weird and wonderful ride for people that are long," said Powerex's Peterson, who added it may be time to reflect on power prices like stock prices: "there is no longer any underlying rationale to the fundamentals."

The price spikes also raised concerns about possible market manipulation, but hard evidence was difficult to come by. Nonetheless, many felt the imperfections of the California market allowed generators there to hold supply off the market until the price was right. "They've figured out the PX rules and that they can hold off" on selling power, Canon said, until the price is high enough. And given what's happening with prices in California, "someone might guess they could bring Northwest prices up to the California levels," one industry watcher said, by controlling generation here.

Whatever the reasons, the high prices are likely to have a long-lasting impact on the NW power market.

"Once you get speculation and this kind of fever at this price level...[prices] have to drop a lot to get into the reasonable range," said ICNU's Canon. "It's market psychology. Prices are based not on cost but on market opportunities."

"And this is mid-June," he added. "This isn't even the hot time" *[Jude Noland]*.

CLEARING UP is a weekly report to clients of the NewsData Service of NewsData Corporation covering public utility and energy policy development, markets, litigation and resource development in the Northwestern United States and Canada. ISSN 0738-2332. For NewsData subscription information, call (206) 285-4848. Telefax: (206) 281-8035. **INTERNET:** www.newsdata.com. **EDITORIAL OFFICES:** Mail: Box 900928 Queen Anne Station, Seattle, WA 98109-9228; Express delivery: 117 West Mercer Ave., Seattle, WA 98119. E-Mail: newsdata@newsdata.com.

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APPENDIX 8

SECURITIES AND EXCHANGE COMMISSION
Washington D.C. 20549

FORM 8-K

CURRENT REPORT

**PURSUANT TO SECTION 13 OR 15(D) OF
THE SECURITIES EXCHANGE ACT OF 1934**

Date of Report (Date of earliest event reported): June 21, 2000

AVISTA CORPORATION

(Exact name of registrant as specified in its charter)

Washington	1-3701	91-0462470
(State or other jurisdiction of incorporation or organization)	(Commission File Number)	(I.R.S. Employer Identification No.)

1411 East Mission Avenue, Spokane, Washington	99202-2600
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: 509-489-0500
Web site: http://www.avistacorp.com

(Former name or former address, if changed since last report)

Item 5. Other Information

A copy of the press release regarding significant increases in energy expenses and the impact on Company earnings is attached hereto as Exhibit 99 and is incorporated herein by reference. Neither the filing of any press release as an exhibit to this Current Report nor the inclusion in such press releases of a reference to the Company's Internet address shall, under any circumstances, be deemed to incorporate the information available at such Internet address into this Current Report. The information available at the Company's Internet address is not part of this Current Report or any other report filed by the Company with the Securities and Exchange Commission.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

AVISTA CORPORATION
(Registrant)

Date: June 21, 2000

/s/ Jon E. Eliassen
Jon E. Eliassen
Senior Vice President and
Chief Financial Officer
(Principal Accounting and
Financial Officer)

AVISTA Corp.

News Release

Contact: Media: Steve Becker (509) 495-4264 sbecker@avistacorp.com
Investors: Dave Brukardt (509) 495-2833 dbrukardt@avistacorp.com

NOTE: *Avista Corp. will hold a conference call for analysts at 10:30 a.m. Eastern Daylight Time on Wednesday, June 21, 2000. To participate in the conference call, dial (712) 257-2791 and use the password "Avista investor conference call."*

A replay of the conference call will be available after 1:30 p.m. EDT at (402) 998-0613 for 48 hours following the conference call.

FOR IMMEDIATE RELEASE:
June 21, 2000
7:00 a.m. EDT

Avista Corp. Incurs Significant Increases in Energy Expenses Due to Sustained Peaks in Purchased-Power Costs Q2 Earnings Expected to be Breakeven

Value Creation Strategies Remain on Track

Spokane, Wash.: Avista Corp. (**NYSE: AVA**) today announced that unprecedented sustained peaks in electric energy prices throughout the Pacific Northwest and California in May and June, compounded by a wholesale short position exceeding management guidelines, are contributing to significant losses for the second quarter at the company's regulated utility operation.

Avista Utilities is expected to spend approximately 25 percent more for purchased power this year because of sustained price peaks, causing it to lose more than $90 million in gross margin in the second quarter due to additional power costs. If current pricing levels sustain through year-end, additional potential losses of at least $50 million in gross margin could occur.

The company's unregulated Avista Energy unit is expected to earn an estimated $70 million or more in gross margin in the second quarter, reflecting current results as well as the mark-to-market value of its contracts. Based on current projections, Avista Corp. expects to post breakeven results for the second quarter and for the full year, before preferred dividends. This performance reflects Avista Energy's positive results and the gain on the May 4 sale of its minority interest in a coal-fired generating unit in Centralia, Wash.

The utility's short position was compounded by the sale of the Centralia plant, which reduced its system capacity by 175 megawatts. Avista's interest in this plant was sold because of the future high environmental mitigation costs related to the plant. This transaction resulted in an estimated after-tax net gain of $34 million of which approximately $26 million will be returned to Avista Utilities' customers and the remaining $8 million net gain will be reflected in Avista Corp.'s second quarter earnings. As part of the Centralia sale, Avista Utilities entered into a favorably priced contract to purchase 175 megawatts from the Centralia plant beginning in July 2000. Because of lower power pricing at the time of the sale and historical trends, Avista Utilities did not seek to cover the months of May and June with firm commitments. In hindsight, not covering this short position was a mistake.

Avista Utilities President Edward Turner said, "We believe the electric energy markets in the Northwest are fundamentally changing. Based on historical trends, our Avista Utilities second-quarter business plan had forecast on-peak power prices at $19 levels. In recent weeks, Avista's on-peak power costs averaged $60 per megawatt in May and over $100 per megawatt in June, with spikes as high as $750 per megawatt. Prices are at an unprecedented level, the likes of which have never been seen in the Pacific Northwest, without any apparent relationship to actual costs of generation." (Note: The attached "Mid-Columbia Weekly On-Peak Prices" chart provides additional data points on power pricing. Link to the chart at www.k.itgo.com/avista.html.)

T. M. "Tom" Matthews, Avista Corp. chairman, president and chief executive officer, said, "We are taking extensive measures to address our power cost issues, minimize our risk and mitigate our utility's financial hardship. These efforts include company-wide administrative expense reductions, cutbacks in utility capital expenditures, the elimination of short-term wholesale commodity sales within the utility not related to optimizing resources for its customers, an aggressive review of alternatives for adding generation and an immediate request for an accounting order permitting the utility to recover its extraordinary power costs associated with utility retail operations."

Avista's general rate case, which is pending before the Washington Utilities and Transportation Commission (WUTC), includes a request to allow Avista Utilities to implement an energy cost adjustment mechanism. This mechanism would allow increases and decreases in energy costs to be passed through to customers as incurred, without a general rate case, similar to Avista's power cost adjustment mechanism in Idaho.

Additionally, in recognition of the need for additional generation in the Pacific Northwest, Matthews noted that the company's Avista Power unit recently broke ground on a 250-megawatt plant in Idaho. Avista Power is in the final stages of closing on a second 250-megawatt plant to be constructed next year in Oregon. Both projects will be powered by efficient, combined-cycle natural gas turbines.

- more -

As discussed in Avista Corp.'s annual report on Form 10-K, the wholesale electric business has been a secondary, but significant, part of Avista Utilities' business strategy. The wholesale business has included marketing capacity and energy under long-term contracts and trading energy on a short-term basis. Avista Utilities will in the future eliminate all trading activity not related to optimizing its resources.

Consistent with previous years, during the second quarter Avista Utilities made purchases of energy in order to satisfy its obligations to retail and long-term wholesale customers, to the extent that the company's own generating resources were not sufficient. Due to the spikes in power described above, the price of these purchases was significantly higher than the levels of purchased power expense recoverable from customers.

In addition, an Avista Utilities energy trader entered into excessive levels of short-term, fixed-price contracts for wholesale sales for delivery of power through October 2000, without making matching purchases at the time. Avista Utilities was forced to buy additional power at prices significantly higher than the selling prices to cover those contracts.

The volume of short-term wholesale sales exceeded management guidelines. When senior management became aware of the short positions, it was determined, in light of projected market conditions based on historical pricing data, that the most prudent course of action was to avoid the high costs of immediate action to offset the effect of these positions. Instead, the utility began to gradually diminish its exposure. This process has been impeded by the continuing high levels of market prices and lack of liquidity in the power markets.

During the balance of the year, the demands on Avista Corp. cash resources are expected to increase significantly. Additional cash needs include increased purchased power expense, as well as calls for cash collateral by Avista Energy's counterparties. Avista Corp. anticipates, based on information currently available, that it will be able to satisfy all cash requirements.

Matthews said, "We believe we are addressing all of the near-term issues facing the utility and we remain confidently focused on Avista's strategies for value creation and growth. We're continuing to create value with the growth of our industry-leading Avista Advantage B2B e-commerce business and with the development of our innovative Avista Labs PEM fuel cell subsidiary. We are in the process of identifying the best timing for unlocking the value in these businesses as well as our telecom business so we can maximize shareholder value."

Avista Corp. is an energy, information and technology company whose utility and subsidiary operations focus on delivering superior products and providing innovative solutions to business and residential customers throughout North America.

Avista Corp.'s affiliate companies include Avista Utilities, which operates the company's electric and natural gas generation, transmission and distribution business. Avista's non-regulated businesses include Avista Advantage, Avista Labs, Avista Communications, Avista Energy, Avista Energy Canada, Ltd., Avista Power, and Avista Ventures, the parent of Avista Development and Pentzer Corporation. Avista Corp.'s stock is traded under the ticker symbol "AVA." For more information about Avista Corp. and its affiliate businesses, visit the corporate website at www.avistacorp.com.

Avista Corp. and the Avista Corp. logo are trademarks of Avista Corporation. All other trademarks mentioned in this document are the property of their respective owners.

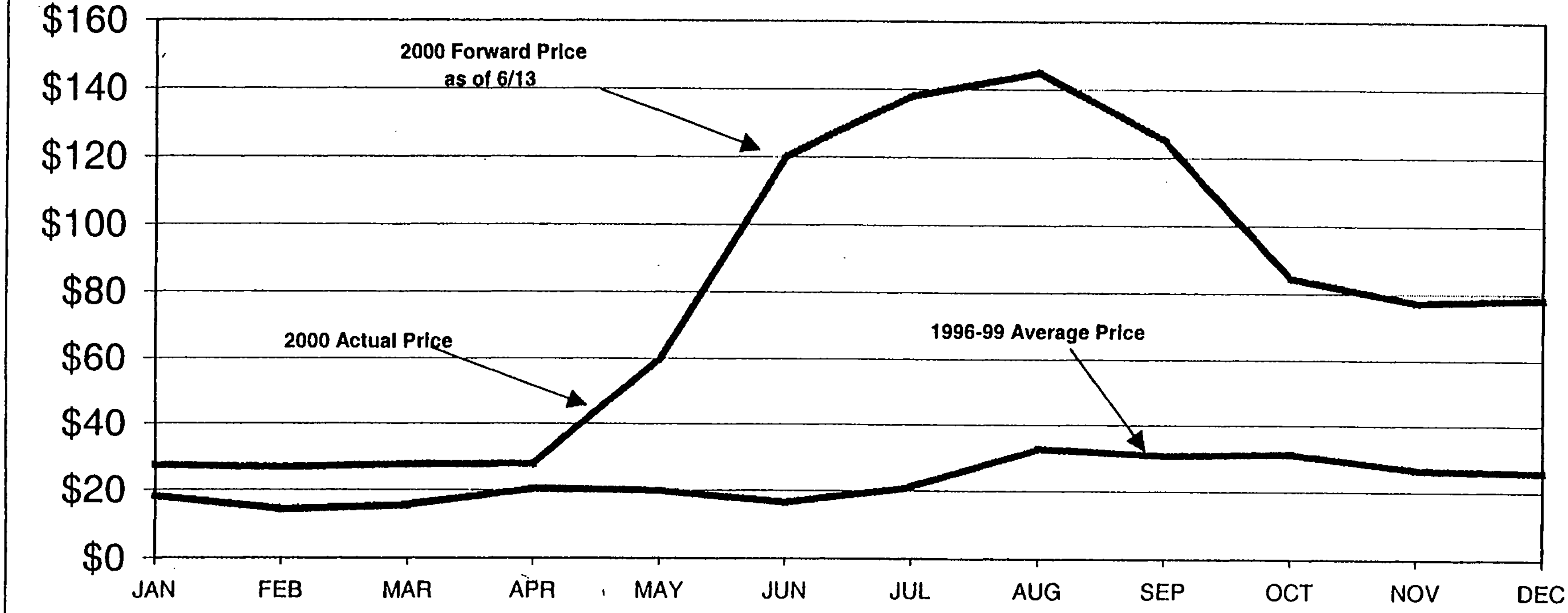
This news release contains forward-looking statements regarding the company's current expectations. These statements are subject to a variety of risks and uncertainties that could cause actual results to differ materially from the expectations. These risks and uncertainties include, in addition to those discussed herein, all of the factors discussed in the company's Annual Report on Form 10-K for the year ended Dec. 31, 1999, and Form 10-Q for the quarter ended March 31, 2000.

-- 0033 --

Note: Graphics located at www.k.itgo.com/avista.html

MID-COLUMBIA WEEKLY ON-PEAK* PRICES

Historical Prices 1996-May 2000; Jun-Dec 2000 forward prices



*weekly on-peak: Monday through Saturday 6 AM - 10 PM
Forward Price Source: Megawatt Daily, NYMEX Futures Results for 6/13/00; California-Oregon-Border

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The Commission has determined these problems justify continuing the method used in the previous rate case. That method is straightforward -- instead of estimates or appraisals, the company considers the gain or loss at the time of transfer to a subsidiary, or sale, and apportions that gain or loss between ratepayers and shareholders based on the time the property was in and out of rate base.

The second sub-issue is the treatment of the remaining gain from the previous rate proceeding. The Commission agrees with the company that the remaining balance should be added to any new gains and amortized over the life chosen for the new gains. The remaining balance should therefore be amortized over three years. This treatment is consistent with the Settlement Agreement.

The final sub-issue is the proper amount of excise tax. The difference between the company and Commission Staff is only $6. The Commission accepts the company's figure.

As a result of the Commission's determination on these sub-issues, the proper adjustment is $392,152. This includes the gains on seven of nine properties in Exhibit 987 as calculated by staff in Exhibit 789. Items 24 and 29 will be included in the next general rate case.

5. 2.08 Storm Damage

The Commission must determine both the proper method for future accounting for storm damage and the appropriate method of calculating the adjustment in this case.

The company expensed an annual amount based on the preceding general rate case. The level of accrual assumed by the company was the nominal level used in each proceeding. The company continued to expense the same amount annually until the next general rate case order, without regard to growth between rate cases of the company's sales or rate base.

When the company booked the expense, it credited a storm damage reserve. When actual storm damage expenditures were made, the company debited the storm damage reserve. As a result, when the company experiences less cost than the level of accruals, the company builds a reserve balance. However, when the company expends more than it has accrued, it creates a reserve deficit. The company would be allowed to book this reserve deficit only if it were a regulatory asset. The company claimed that because the Commission has adopted an amortization of the reserve balance in several previous proceedings, the Commission in effect accepted the reserve deficit as a regulatory asset.

The Commission Staff stated that the company has improperly created a regulatory asset for storm damage without express authorization from the Commission. Commission Staff witness Thomas Schooley argued that the company's reliance on previous Commission Orders is unfounded. Mr. Schooley contended that the accounting as just described is improper general accounting, that it transfers substantial financial risk from the stockholders to the ratepayers, and that the creation of a reserve deficit is in violation of the Uniform System of Accounts because the Commission did not approve this accounting treatment.

Mr. Schooley proposed normalizing the storm damage expense based on a six-year period, and that truly extraordinary events should be deferred as extraordinary property damage and amortized into rates over a six-year period. Commission Staff also noted that the company in previous general rate cases has in fact been regulated on a normalized basis rather than on a deferral method as suggested by the company. Mr. Schooley proposed to define "catastrophic event" as one affecting 25% or more Puget customers, occurring infrequently, and affecting a wide geographic area.

The dispute between Commission Staff and company results in several differences. Commission Staff does not include amortization of the $16.5 million reserve deficit. In place of this, Commission Staff allows the company to amortize $11 million of extraordinary property loses. Commission Staff used a six-year period versus the four-year amortization period proposed by the company. With respect to ongoing storm damage, company witness John Story testified to a level of approximately $4 million. This is close to the four-year average calculated by Mr. Schooley's exhibit, excluding the extraordinary events. Commission Staff recommended ongoing expenses of $3 million based on a six-year average.

FEA witness Hugh Larkin contended that the company improperly charges overhead costs to the reserve account. He argued that ongoing expense should not be charged to a reserve account unless those expenses represent incremental costs to the company. These overhead costs are not incremental and should not be deferred.

The company argued that it has accounted for storm damage on a consistent basis and that Mr. Larkin's claims are without foundation.

The Commission agrees that it may be unclear from previous Orders what accounting treatment is appropriate for storm damage. Because those Orders appear to have tacitly approved the reserve account treatment used by Puget, the Commission will allow the entire $16.5 million to be amortized in rates. This amount should be amortized over six years, as recommended by Commission Staff.

From the effective date of this Order, the company should account for storm damage in the manner recommended by Commission Staff. The deferred treatment used by Puget transfers the risk, and more, to the ratepayers. As demonstrated in Exhibits 876 and 877, if the company had increased its accrual levels based on its increase in revenues -- thus holding the expense to a constant percentage of revenue -- the reserve balance would have been reduced by $2 million since the Order in U-85-53. Failure to do so is unfair to ratepayers.

The treatment used by the company is not truly self insurance. The company does not adjust the accruals based on any factor other than general rate case Orders. If the company position prevailed, insurance would be provided by ratepayers.

The Commission therefore adopts the Commission Staff's recommendation to use a normalized level for storm damage. The amount used should be based on a six-year average, to somewhat dampen weather variability, to accommodate the current PRAM mechanism, and to reflect the intention that general rate cases be filed every 3 years.

The Commission also adopts for now Mr. Schooley's definitions of catastrophic/extraordinary events, and encourages the company to meet with interested parties to refine this definition. Extraordinary losses are, thus, defined as events which affect 25% of Puget's customers, occur infrequently, and affect wide geographic areas. If the company has any question whether a storm is a catastrophic/extraordinary event, which may be booked to the storm damage account, it should seek Commission guidance on a case by case basis.

The company may amortize $16.5 million in its storm damage reserve over six years. The resulting adjustment based on Mr. Schooley's calculation adjusted for the $16.5 million, instead of $11.1 million, is a $2,747,506 decrease in net operating income.

6. 2.09 Self Insurance

The company claimed to self insure for three risk categories: all risk property damage, liability, and workers compensation. The company proposed an adjustment to the three as a group. The company calculation was based on an average of the last four years' charges in these categories, plus a four-year amortization of a reserve deficit in the all risk property

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SERVICE DATE
JUL - 8 1998

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Petition of	
PUGET SOUND ENERGY, INC.	Docket UE-980877
For an Order Regarding the Accounting Treatment of a Proposed Virtual Right-Of-Way Program	ORDER AUTHORIZING ACCOUNTING TREATMENT

On June 23, 1998, Puget Sound Energy ("PSE" or "the Company") filed with the Commission a Petition pursuant to WAC 480-09-420(7) for an order regarding the accounting and ratemaking treatment of a proposed Virtual Right-Of-Way Program ("VROW Program"). According to the Petition, the VROW Program allows the Company the opportunity to achieve significant improvements in the reliability of its electric service. The Company expects the VROW Program to significantly reduce non-storm tree related overhead outages, the number and duration of outages, and repair costs during major storm events. These benefits are realized over 15-20 years while the Program expenditures occur within the first five years. Therefore, the Company requests an accounting order authorizing it to defer the expenses as a regulatory asset and to begin immediate amortization of the costs of the Program on a half month convention method over a ten-year period.

The Company states that in its distribution planning process, it seeks new and innovative ways to meet customers' reliability needs at the lowest possible long-term cost. According to the Company, the VROW Program responds to customers' desires and quickly delivers the most benefit for the least cost. The Company submits that its filing is responsive to the following statement in the Merger Order:

> Given the storms we experienced this winter, the Commission has a heightened awareness of the need to explore ways to improve the reliability of electric transmission and distribution facilities. . . . [V]egetation management goes beyond merely "cutting trees". Long term reliability of the distribution system would seem to involve a comprehensive look at the causes of system outages, studying alternative ways of improving system reliability, and assessing the costs of different management alternatives against their benefits before making a decision on how to proceed.[1]

[1]Docket Nos. UE-951270 and UE-960195, Fourteenth Supplemental Order at pages 32-33.

According to the Company, it historically constrains its primary vegetation management efforts within its designated right-of-way. Outside the designated right-of-way, the Company removes dangerous trees only when necessary. The Company asserts the Virtual Right-of-Way Program achieves the benefits of widening the Company's dedicated right-of-way without actually buying land or the rights to maintain it. Under the Program, PSE will selectively remove trees outside of its dedicated right-of-way with the landowners' permission. The expected cost is $43 million over the next five years. PSE claims alternatives to the VROW Program, such as actually securing a wider right-of-way or accepting the status quo, are either cost-prohibitive or ignore the necessary improvements in reliability. PSE states the Virtual Right-of-Way Program is an extraordinary one-time program that produces long-term benefits as compared to the current on-going vegetation management efforts.

The Company's petition seeks deferred accounting treatment for ratemaking and regulatory accounting purposes. PSE proposes to defer the costs of the VROW Program in account 182.3, Other Regulatory Assets, and to amortize the balance to the proper expense accounts over 10 years. The Company proposes to amortize immediately each month's VROW expenditures using a half month amortization convention. PSE defines VROW Program costs as those costs incurred beyond the dedicated right-of-way and includes only the direct costs of identifying and removing specific trees, additional tapered trimming of conifer overhang between 12 and 15 feet, and replacing trees with more appropriate species at landowners' request. Alternatives to removing trees, such as installing underground conductors, use of tree wire, or reconfiguring overhead construction, will be considered when it is financially and physically viable. PSE requests normalization of federal income tax benefits related to the VROW Program over the amortization period. PSE also proposes to include all related balance sheet accounts in working capital. The Company proposes no changes for costs associated with its traditional, dedicated right-of-way tree trimming program.

The Company specifies it will evaluate the effectiveness of the Program through development of a measurement model. Beginning in September 1998, PSE will start tracking outages at a grid number level and developing improvement and maintenance plans at a circuit's subsection. PSE will use this information to estimate historical performance for a circuit subsection, capture outage information, estimate costs for improving or maintaining the subsection, and capture actual costs for any work performed on the subsection. The Company will report annually on effectiveness of the Program following the first full year of Program and evaluation model operation. The first report will be issued in September 1999. At each reporting period for the first four years, the Company will determine whether Program expenditures have resulted in measurable system reliability improvements and if so, will continue to implement the Program. If the Company cannot demonstrate measurable system improvements have resulted from the preceding years' Program implementation, then further expenditures will be curtailed.

According to the Company, this proposal is consistent with the accounting treatment for the purchase of additional right-of-way and the initial clearing of trees under the traditional approach. The accounting treatment related to this proposal is designed to achieve the benefits of this virtual right-of-way program without increasing the Company's revenue requirements.

FINDINGS

THE COMMISSION FINDS:

1. PSE is a public service company furnishing electric and gas service primarily in the Puget Sound region of the State of Washington and is subject to the regulatory authority of the Commission as to its rates, service, facilities and practices.

2. On June 23, 1998, PSE filed with the Commission a Petition for an order regarding the accounting and ratemaking treatment of a proposed Virtual Right-Of-Way Program ("VROW Program").

3. The accounting treatment proposed by PSE is reasonable, and should be approved.

ORDER

WHEREFORE, THE COMMISSION HEREBY ORDERS:

1. Authorization is hereby given for PSE to:

   (a) Capitalize, for recovery in rates, the VROW Program costs in account 182.3, Other Regulatory Assets, as a deferred charge; (Deferral will cease when the VROW Program is completed, terminated, or June 30, 2003, whichever is sooner.)

   (b) Commence amortization in 1998 of the regulatory asset using half month amortization convention over a 10 year period;

   (c) Normalize federal income taxes related to the VROW Program expenditures; and

   (d) Include the regulatory asset and related deferred tax accounts in working capital for ratemaking purposes.

(d) Include the regulatory asset and related deferred tax accounts in working capital for ratemaking purposes.

2. PSE will prepare and submit annual evaluations of the VROW Program's effectiveness. The first report will be issued in September 30, 1999 and will continue annually through September 30, 2003, inclusive. The Company will also submit with the annual report PSE's actual expenditures under both the VROW and Standard Vegetation Management Programs. The Company's VROW program communication strategy will be included in the evaluation process.

3. Nothing herein shall be construed to waive or otherwise impair the jurisdiction of the Commission over the rates, services, accounts, and practices of Applicant, Puget Sound Energy. Under the Commission's general ratemaking authority, such regulatory accounting and the potential ratemaking treatment of the Company's costs under the Virtual Right-of-Way Program are subject to evaluation and review in subsequent rate proceedings. PSE bears the burden of proving the fairness, justness, and reasonableness of these matters in such proceedings.

4. The Commission retains jurisdiction to effectuate the provisions of this Order.

DATED at Olympia, Washington and effective this 8 th day of July, 1998.

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

ANNE LEVINSON, Chair

WILLIAM R. GILLIS, Commissioner

BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-________

APPENDIX 11

SERVICE DATE

FEB 2 3 2000

BEFORE THE WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

In the Matter of the PETITION OF PUGET SOUND ENERGY, INC., For an Order Regarding the Accounting Treatment for Costs of its Electric Environmental Remediation Program	)	Docket No. UE-991796 ORDER AUTHORIZING ACCOUNTING TREATMENT

BACKGROUND

On November 19, 1999, Puget Sound Energy, Inc., ("PSE" or the "Company") filed a Petition with this Commission under WAC 480-09-420(7) seeking an order regarding the treatment of costs incurred by the Company under its electric environmental remediation program in response to federal and state laws regarding hazardous wastes. In its Petition, the Company requests an order which:

> authorizes the Company to defer the costs incurred in connection with the recently added component, White River "Buckley Headworks." A detailed description of the White River Buckley Headworks site is included as Exhibit A to this petition. Costs so deferred would be amortized during the next succeeding five-year time period commencing on the date that all costs net of recoveries become known per Merger Order UE-960195, issued on February 5, 1997 (Merger Order).

The Company's Petition states that the requested relief is necessary to insulate the Company's customers from fluctuations in rates due to the variability of environmental remediation costs and recoveries from insurance or third parties. In addition, the Petition states that the requested accounting order would allow the Company to avoid the negative financial impact that otherwise would be required in accounting for these costs under current financial reporting requirements.

According to the Petition, the Company currently has underway an environmental remediation program in response to federal and state laws regarding hazardous wastes.

In its Petition, the Company states that per Commission Order No. UE-911476, issued April 1, 1992, it was authorized deferral accounting treatment associated with particular components of its electric environmental remediation program costs. According to the Company, the order which authorized deferral accounting treatment for such costs stated that this treatment was considered to be appropriate in light of the variability and unpredictability of environmental expenditures. According to the Company, the variable and unpredictable nature of environmental expenditures has not changed and is not expected to change in the future.

After discussion with the Commission Staff, the Company agreed that the environmental remediation costs deferred pursuant to the requested accounting order would be subject to the following conditions:

a. Any unamortized costs existing at the time of the Company's general rate proceedings would be subject to review. Any costs shown to be imprudent will be subject to disallowance for rate recovery purposes.

b. Any amortization expense and unamortized balance at the time of the next general rate proceeding will be considered in determining rates;

c. Any unamortized costs will be included in the calculation of working capital in future rate proceedings.

d. Costs eligible for such accounting treatment would include only those amounts paid to outside vendors or contractors (i.e., investigation and feasibility studies, sampling, evaluation, monitoring, materials, remediation and removal) and would not include internal employee expenses and legal costs; and

e. Costs that are deferred will be reduced by any insurance proceeds or payments from other responsible parties received by the Company in respect of such costs.

f. The Company will normalize the tax benefits associated with these costs.

g. The Company will submit quarterly reports detailing the status of the various remediation activities, insurance and third party recoveries, and the level of costs being incurred.

FINDINGS

THE COMMISSION FINDS:

1. PSE is a public service company furnishing electric and gas service primarily in the Puget Sound region of the State of Washington and is subject to the regulatory authority of the Commission as to its rates, service, facilities and practices.

2. On November 19, 1999, PSE filed with the Commission a Petition for an order regarding the accounting treatment for costs it incurs in connection with its White River "Buckley Headworks" environmental remediation program.

3. The accounting treatment proposed by PSE, subject to certain conditions described above, is reasonable and should be approved.

ORDER

THE COMMISSION ORDERS:

1. Authorization is hereby given for PSE to:

a. Defer the costs incurred in connection with the recently added component, White River "Buckley Headworks," to the Company's environmental remediation program; and

b. Amortize such costs deferred over a five-year period commencing on the date that all costs net of recoveries become known, consistent with the Merger Order.

2. Such deferral and amortization of costs incurred pursuant to its electric environmental remediation program are subject to the above conditions agreed to in discussions between PSE and Commission Staff.

3. Nothing herein shall be construed to waive or otherwise impair the jurisdiction of the Commission over the rates, services, accounts and practices of Applicant, Puget Sound Energy.

4. The Commission, under its general ratemaking authority, has the ability in subsequent PSE general rate proceedings to evaluate the reasonableness of the Company's expenditures associated with the electric environmental remediation program. The Company bears the burden of proof in any such proceeding regarding these matters. Any costs determined to be unreasonable or imprudent in such proceedings are subject to disallowance.

5. The Commission retains jurisdiction to effectuate the provisions of this Order.

DATED at Olympia, Washington, and effective this 23rd day of February, 2000.

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Carole J. Washburn

CAROLE J. WASHBURN, Secretary

SERVICE DATE

APR - 1 1992

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Petition of Puget Sound Power & Light Company for an Order Regarding the Accounting Treatment for Costs of Its Environmental Remediation Program.	DOCKET NO. UE-911476 ORDER AUTHORIZING ACCOUNTING TREATMENT

On December 24, 1991, Puget Sound Power & Light Company ("Petitioner" or the "Company") filed a Petition with this Commission under WAC 480-09-420(7) seeking an order regarding the treatment of costs incurred by the Company under its environmental remediation program in response to federal and state laws regarding hazardous wastes. In its Petition, the Company requests an order which:

(1) approves Petitioner's current treatment for costs incurred in connection with its environmental remediation program prior to the date of such order, and

(2) authorizes Petitioner to defer the costs incurred after the date of such order in connection with the environmental remediation projects identified in the Company's Petition. Costs so deferred would be recovered in rates to be established in future rate proceedings.

Petitioner claimed that the requested relief was necessary to insulate the Company's customers from fluctuations in rates due to the variability of environmental remediation costs. In addition, the Petition states that the requested accounting order would avoid the negative financial impact that otherwise would be required in accounting for these costs under current financial reporting requirements.

According to the Petition, the Company currently has underway a major environmental remediation program in response to federal and state laws regarding hazardous wastes. The principal statutes cited by Petitioner are, on the federal level, the Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA (42 U.S.C. Sections 9601 et seq.) and, on the state level, the State Model Toxic Control Act of 1988 (Chapter 70.105D) (The "State Act"), which empowers the state Department of Ecology as the principal state agency to regulate environmental matters. In order to comply with these federal and state environmental laws, Petitioner is pursuing an environmental remediation program currently consisting of three major components: (a) investigations and remedial actions at three sites not owned by Petitioner which have been designed as "Superfund" sites under CERCLA, and at which Petitioner has been designated as a "potentially responsible party", or "PRP"; (b) remedial actions at a Company-owned site (Electron) which has been designated for cleanup pursuant to the State Act; and (c) an underground storage tank program pursuant to which Petitioner has tested its tanks and the ground surrounding them, and is removing or replacing numerous such tanks pursuant to requirements of federal and state law. From the Petition, it appears that Petitioner will incur significant remediation costs in connection with its environmental remediation program during the next few years. Because these activities are being undertaken to fulfill obligations imposed by state and federal environmental agencies, the costs incurred are alleged by the Company to be current and legitimate business expenses.

Petitioner claims that historical ratemaking methods would not provide an acceptable means of recovering these costs. It therefore seeks to defer, for recovery in rates to be established in future rate proceedings, the costs it incurs in connection with these specified activities. As stated in the Petition, the costs incurred by the Company for environmental remediation will not be incurred at an even rate during the coming years. Moreover, the costs which the Company will incur are extremely difficult to forecast due to changing regulations and the developing science of environmental cleanups. Because of this variability and unpredictability of expenditures, the deferred accounting requested in the Petition is an appropriate method for treating these costs for ratemaking purposes. Granting the essential elements of the requested accounting treatment would also allow the Company to avoid having to book as a current expense its estimate of future remediation costs associated with known sites.

In response to the Company's Petition, the Commission Staff reviewed the request and gathered additional information regarding the expenditures identified by the Company. The Commission Staff proposed that the accounting treatment be modified in a number of respects.

1. According to the Commission Staff, the prior costs recorded by the Company in retirement and insurance accounts may distort future depreciation and insurance expense. Staff therefore proposed that these costs since September 30, 1988--the end of the test period in the Company's last rate proceeding--be transferred to the deferred account and treated in the same manner as costs incurred

subsequent to the Commission Order. Company employee and legal costs would be expensed to the appropriate operating expense accounts. Costs prior to October 1, 1988, would remain in the accounts originally charged.

2. Commission Staff proposed that the deferred account not be allowed to accrue interest. instead, the account balances would be included as part of the Company's working capital.

3. Any recovery of insurance proceeds would be treated in a manner that corresponds with the treatment of the underlying costs to which the recovery relates. If the underlying costs cannot be identified, as may be the case with an insurance settlement, the Company would allocate the insurance recovery based on the percentage of costs charged to the deferred and operating expense accounts, respectively.

4. Commission Staff proposed that the Company be required to submit quarterly reports detailing the status of the various remediation projects and the level of costs being incurred.

These proposed modifications were discussed with the Company, and the Company was agreeable to the incorporation of these modifications into our order. The Company therefore submitted an Amendment to its Petition to reflect the modifications agreed upon by the Company and the Commission Staff. We agree that the modifications proposed by the Commission Staff are reasonable, and we therefore shall include them in our order.

FINDINGS OF FACT

THE COMMISSION FINDS:

1. Puget Sound Power & Light Company is engaged in the business of furnishing electric service within the state of Washington as a public service company, and is subject to the jurisdiction of this Commission.

2. On December 24, 1991, the Company filed a petition seeking an order regarding the accounting treatment for costs it incurs in connection with its environmental remediation program. The requested accounting treatment was modified in an Amendment to the Petition filed by the Company on March 24, 1992. In its filing, the Company identified the particular components of its environmental remediation program to which the requested accounting treatment would apply: (a) the three sites for which it has

been identified as a PRP under CERCLA, (b) its Electron site, and (c) its underground storage tank program.

3. As stated in the Petition, the activities performed by the Company in connection with its environmental remediation program are being undertaken to comply with federal and state environmental laws and regulations, and thus are current and legitimate business expenses of the Company. Moreover, it is important that utilities not be discouraged from carrying out their obligations in environmental efforts. Unless the costs incurred by the Company in connection with its program are shown to be imprudent in subsequent rate proceedings, such costs would be recoverable in Petitioner's retail rates.

4. The accounting treatment proposed in the Petition for remediation costs is appropriate in light of the variability and unpredictability of environmental expenditures.

O R D E R

WHEREFORE, THE COMMISSION HEREBY ORDERS:

1. Approval is hereby given for the accounting treatment proposed in the Amendment to the Petition with respect to costs incurred since September 30, 1988 and prior to the date of this Order in connection with the Company's environmental remediation program. This accounting treatment consists of the following: (a) transferring the remediation costs incurred by Petitioner at the sites identified in the Petition, previously charged as a cost of retirement, to a deferred account; (b) transferring the remediation costs incurred by Petitioner at its Electron site from the property damage reserve (Account 228) to a deferred account; and (c) transferring the remediation costs charged as a cost of retirement under the Company's underground storage tank program to a deferred account. The accounting treatment described above shall not apply, however, to internal employee expenses and legal costs, which shall be expensed.

2. For costs incurred by the Company after the date of this Order in connection with its environmental remediation program, as such program is identified in the Petition, the Company is authorized to defer such costs for recovery in rates in future rate proceedings. Costs eligible for such accounting treatment shall include only those amounts paid to outside vendors and contractors (e.g., investigation and feasibility studies, sampling, evaluation, monitoring, materials, remediation, removal, disposal and post-remediation work) and do not include legal costs.

3. Costs deferred in accordance with paragraphs 1 and 2 above shall be subject to the following conditions:

(a) Any deferred costs shown to be imprudent in future rate proceedings of Petitioner are subject to disallowance;

(b) Deferred costs will be recovered in rates using an appropriate method as determined in such proceedings;

(c) Deferred costs will be included in the calculation of the Company's working capital in future rate proceedings; and

(d) Deferred costs will be reduced by any insurance proceeds or payments from other responsible parties recovered by Petitioner in respect of such costs. (Conversely, proceeds or payments received by Petitioner in respect of costs incurred prior to October 1, 1988 or costs expensed subsequent to October 1, 1988 will not be used to reduce deferred costs.

4. The Commission retains jurisdiction to effectuate the provisions of this order.

DATED at Olympia, Washington, and effective this 1st day of April, 1992.

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Sharon L. Nelson

SHARON L. NELSON, Chairman

R. D. Casad

RICHARD D. CASAD, Commissioner

A. J. Pardini

A. J. PARDINI, Commissioner

BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-________

APPENDIX 12

JUN 9 1977

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, vs. THE WASHINGTON WATER POWER COMPANY, Respondent.	CAUSE NO. U-77-37 SECOND SUPPLEMENTAL ORDER

The above-entitled proceeding involves a filing by The Washington Water Power Company, respondent, designed to add a surcharge to its presently effective tariff. Hearing on the tariff revision was held in Spokane, Washington, on May 25 and 26, 1977, before Chairman Robert C. Bailey, Commissioner Elmer C. Huntley, Commissioner Frank W. Foley, and Administrative Law Judge William Metcalf.

The parties were represented as follows:

COMPLAINANT: WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION
By James R. Cunningham
Assistant Attorney General
Temple of Justice
Olympia, Washington 98504

RESPONDENT: THE WASHINGTON WATER POWER COMPANY
By Robert L. Simpson and Alan P. O'Kelly
Attorneys at Law
1400 Washington Trust Bank Building
Spokane, Washington 99204

CONSUMER PUBLIC: PEOPLE OF THE STATE OF WASHINGTON
By Donald A. Ericson
Special Assistant Attorney General
708 Old National Bank Building
Spokane, Washington 99201

The Washington Water Power Company filed, on May 2, 1977, a revision to its currently effective Tariff WN U-23; the revision is entitled EXCESS POWER COST SURCHARGE--WASHINGTON, and its stated purpose is to recover excess power costs incurred as a result of worse than critical water conditions. The operation of these revisions was suspended by Order dated May 4, 1977, and the Commission thereby ordered a hearing to be held on the reasonableness and justness of the surcharge. Hearing was held as related above.

The suspended tariff revision would impose a surcharge of .21 cents per kilowatt hour on all charges for electric energy sold to retail customers in this state where respondent has electric service available, excepting flat rate charges for company-owned or customer-owned street lighting and area lighting service.

The justification for the requested surcharge is based on the fact respondent is being obliged to purchase power from outside sources at abnormally high prices for resale to its customers and that the cost of doing this will impair its ability to earn the rate of return authorized by the Commission in Cause No. U-76-8 (December, 1976). It is, however, to be understood that rate of return on investment plays no part in the relevant evidence respondent offered in support of its request or in the Commission's evaluation of such evidence. Rates of return for utility companies are based on historic test periods which are adjusted to reflect known and measurable proforma conditions. Actual historic facts are, of course, constantly changing and any historical test period obviously cannot constantly be updated. We here deal not with rate of return but with an attempt to offset specific future costs of an abnormal nature.

We agree with counsel for the consumer public that what constitutes an abnormal power purchase and what constitutes an abnormal cost for such purchase are concepts that are not susceptible of clear definition. A wide range of sales of excess power in abundant years and purchases of needed power in shortage years will be experienced over a 25- or 50-year period. Nevertheless, the record herein demonstrates that in May the snow covers feeding the rivers which constitute respondent's power sources were approximately 75 percent below normal and the rivers themselves were approaching 100 percent of critical flow. The record also discloses that faced with the reduction in ability to generate power resulting from below-normal stream flows, respondent was forced to contract with other producers of power in order to meet the needs of its customers and that one of these contracts was particularly stringent in that it required repondent to pay for the contract's kilowatt hour amount regardless of kilowatt hours taken, if any.

The contract referred to is between Cominco, Ltd., (through West Kootenay Power Company) and it requires respondent to purchase kilowatt hours amounting to, insofar as relevant here, 42,067,000 during the approximately 90-day period of June, July, and August. The system cost of this commitment will be $706,557 (utilizing respondent's Exhibit No. 1 methodology). Washington's portion of this cost would be $407,389 (taking into account excise tax, uncollectibles, and operating and maintenance expenses shown in Exhibit No. 10). This finding on the Washington portion of the Cominco commitment excludes sales for resale.

In order to calculate the surcharge required to recover Washington's portion of the Cominco agreement it is necessary to understand that the kilowatt hours respondent will predictably sell during the three-month period under consideration (1,692,-782,000) upon which a surcharge would be applied include sales at rates not within the jurisdiction of this agency. In order to assure that customers paying rates established by this agency do not assume the burden that should be shared by other of respondent's customers, it must be assumed that sales outside this agency's jurisdiction will contribute to the additional revenues deemed warranted under the facts presented herein. Such an assumption has been a long-established tool for setting our transportation rates. The rationale for this assumption was considered in an order in Cause No. T-9733, In the Matter of Increases in Class Rates in Western Washington as Published in WUTC Tariff No. 5-A (1966). Briefly, in situations such as this, it has been the position of the Commission that any increase for revenues under our jurisdiction must also be presumed to take place on sources of revenues not under our jurisdiction because this assures that Washington ratepayers do not assume the burden of costs attributable to other users of a public service company's services; further, public service companies are thus given a standard for dealing with other regulatory bodies or private parties, as the case may be, in their requests of them for revenue increases; and other users of their services are on notice that this Commission expects them to assume their share of the burden of contributing to needed revenues. The suggestion of counsel for the Commission on the point is consistent with long-standing practice and will be accepted. With this adjustment, and utilizing testimony and exhibits of record to make the calculation, the surcharge that will generate the contract commitment found proper above is .044 cents per KWH.

The Commission is of the opinion that the critical stream-flow levels predicted to prevail during the pertinent period of the Cominco contract present respondent with highly abnormal power supply conditions. It is further of the opinion that the costs of meeting these conditions are known and measurable in accordance with established principles of utility accounting. It is the conclusion of the Commission that it will be in the public interest to permit respondent to impose a surcharge of .044 cents per KWH on electric service rendered in this State; that this surcharge will allow respondent to recover the aforesaid contract amount of $407,389; and that this surcharge will establish rates that are fair, just, reasonable, and sufficient.

By agreement of record, respondent will file monthly reports with the Commission that disclose the revenues billed each month by the surcharge. The surcharge and the reports will, of course, continue somewhat beyond the end of August since this surcharge does not become effective with the first of June. It appears appropriate to require such reports 30 days following commencement of the surcharge and each 30-day period thereafter until the surcharge revenue in the amount of $407,389 has been billed. The tariff respondent files to impose a surcharge should provide that it is to be cancelled by the Commission upon respondent's billing surcharges totalling $407,389. Further, though respondent would naturally seek to avoid making refunds in the event of inadvertent billing in excess of $407,389, refiling should provide for cancellation of the surcharge no later than September 30, 1977. Should the monthly report required herein establish that respondent has not billed surcharges totalling $407,389 by September 30, 1977, further order in this proceeding will, of course, be issued to allow another surcharge tariff filing to effectuate the terms of this order.

In addition, it appears appropriate to authorize respondent to seek additional relief through imposition of another surcharge should further deterioration of the stream-flow conditions described in this record require respondent to enter into other supply contracts similar to the Cominco contract before us in order to obtain necessary power for retail sales. In such eventualities, the Commission will allow, by further order in this Cause, formal submission of evidence from parties and then order relief as appears warranted under the circumstances.

Counsel for the Consumer Public presented several witnesses whose testimony again points up the magnitude of the impact of even a comparatively very small increase in the cost of utility services on the economically disadvantaged, the elderly, and others obliged to live on fixed incomes. Utility rates as they bear on social and economic inequities have been examined in depth and considered at length by the Commission in virtually every utility rate proceeding in the past three or four years. The Commission is keenly aware of the many ways that continually increasing utility rates can adversely affect the levels of living of low and fixed income citizens, but solutions to this growing problem must come from the legislative bodies of the states and the nation. They cannot fairly or effectively come from regulatory bodies such as this one on a hearing-by-hearing basis. Our views on this important issue have been stated on numerous occasions and need not be reiterated here.

FINDINGS OF FACT

Having heretofore discussed in detail both the oral and documentary testimony concerning all material matters inquired into and having stated our findings and conclusions, we now make the following summary of these facts. The portions of the preceding detailed findings pertaining to the ultimate facts are incorporated herein by this reference.

1. The Washington Utilities and Transportation Commission is an agency of the State of Washington vested by statute with authority to regulate rates, rules, regulations, practices, accounts, securities, and transfers of public service companies, including electric companies.

2. The Washington Water Power Company, respondent herein, is engaged in the business of furnishing electric service within the State of Washington as a public service company.

3. On May 2, 1977, respondent filed revisions to its currently effective Tariff WN U-23, designated as Fifteenth Revision Sheet B and Original Sheet 59. The schedule reflected on Sheet 59 is entitled EXCESS POWER COST SURCHARGE--WASHINGTON.

4. Respondent's tariff revisions, which were suspended by the Commission, would impose a surcharge of .21 cents per kilowatt hour on all charges for electric energy sold to retail customers in this state where respondent has electric service available, excepting flat rate charges for company-owned or customer-owned street lighting and area lighting service.

5. Snow covers feeding the rivers which constitute respondent's power sources were approximately 75 percent below normal in May and the rivers themselves were approaching 100 percent of critical flow, indicating an extremely abnormal situation that obliged respondent to contract with other producers of electric power in order to meet the needs of its customers.

6. The contract between respondent and Cominco, Ltd., and the projected critical stream-flow levels predicted to prevail during the pertinent period of the Cominco contract present a sufficiently abnormal situation to justify allowing respondent to impose a surcharge designed to lead to recovery of the amount of $407,389. The surcharge on appropriate kilowatt hour sales that will generate this amount is .044 cents per KWH. The derivation of the dollars, kilowatt hours, and appropriate amount of surcharge are summarized above. The Cominco contract cost is known and measurable in accordance with established principles of utility accounting.

7. Monthly reports filed with the Commission will contain the amount of revenue billed from the surcharge during each monthly period and will enable the Commission to know when surcharge revenue of $407,389 has been billed by respondent.

CONCLUSIONS OF LAW

1. The Washington Utilities and Transportation Commission has jurisdiction of the subject matter and of the parties to this proceeding.

2. Authorization of a surcharge of .044 cents per kilowatt hour under the conditions herein described will allow respondent to provide electric service at rates which are fair, just, reasonable, and sufficient.

3. Authorization of a surcharge of .21 cents per kilowatt hour as contained in respondent's filing in this Cause would establish rates for electric service that are excessive, and the filing should be rejected in its entirety.

4. The surcharge hereby authorized will, upon appropriate refiling, be applicable to electric service provided on and after the effective date of said refiling.

5. All motions consistent with the findings and decision herein should be granted; those inconsistent should be denied.

O R D E R

THE COMMISSION THEREFORE ORDERS:

1. The tariff revisions filed by The Washington Water Power Company, respondent, in this cause May 2, 1977, are hereby rejected in their entirety.

2. Respondent is authorized to file tariff revisions comparable to those rejected herein with the exception that the level of the surcharge be .044 cents per KWH and that the schedule wherein the surcharge is reflected contain the language that the schedule is subject to cancellation by action of the Commission in this Cause when it has been determined that recovery in the amount of $407,389 has been billed, but in any event no later than September 30, 1977.

3. The tariff revisions authorized herein shall bear an effective date which allows the Commission at least the day of receipt thereof to consider same; shall reflect no retroactive rate treatment; and shall bear the notation on each sheet thereof, "By authority of order of the Washington Utilities and Transportation Commission, Cause No. U-77-37".

4. A notice of the filing of the tariff revisions authorized herein shall, on the same date as filed or immediately prior thereto, be posted at each business office of respondent in the territory affected thereby, stating that the tariff revisions are to become effective on the date inserted as the effective date in keeping with the foregoing and advising that a copy of each such revision is available for inspection at each such office. The notice shall remain posted at least until the Commission has acted on the revisions.

5. The respondent shall report monthly relative to the revenues billed by reason of the surcharge, as discussed hereinbefore.

6. The Commission may allow by subsequent order in this cause formal submission of evidence should it ever happen that the stream-flow described in the record require respondent to enter into a supply contract similar to the Cominco contract herein.

7. All motions consistent herewith are granted; those inconsistent are denied.

8. Jurisdiction is retained to effectuate the provisions of this order.

Dated at Olympia, Washington, and effective this 9th day of June, 1977.

Robert C. Bailey
ROBERT C. BAILEY, Chairman

Elmer C. Huntley
ELMER C. HUNTLEY, Commissioner

Frank W. Foley
FRANK W. FOLEY, Commissioner

BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-________

APPENDIX 13

Avista Corp.
Secondary Sales, Purchases and Thermal Generation
Dispatch Simulation Model Analysis

60 Years 1929-88, Excludes Centralia, Includes TransAlta

Line No.		Total	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01
1	Short-term Sales	$2,350,500	$105,100	$2,400	$0	$8,800	$54,000	$4,400	$35,700	$130,200	$32,600	$33,000	$1,624,500	$319,800
2	S-T Sales MWh	146,700	10,600	100	0	900	2,700	400	2,000	10,200	2,200	1,400	95,500	20,700
3	Short-term Purchases	$22,934,000	$2,371,000	$2,445,000	$2,971,700	$2,425,100	$1,414,300	$1,613,700	$1,949,000	$1,259,900	$2,082,700	$3,079,300	$222,700	$1,099,600
4	S-T Purchase MWh	931,400	86,200	113,300	109,900	85,000	53,500	78,500	81,500	44,100	89,500	147,800	6,300	35,800
5	Wtd Avg Sec Price	$23.45	$25.58	$21.58	$27.04	$28.33	$26.13	$20.51	$23.77	$25.60	$23.07	$20.86	$18.15	$25.12
6	Colstrip MWh	1,443,400	107,300	143,000	136,100	143,200	138,400	133,500	143,000	120,600	128,700	115,200	90,600	43,800
7	Conversion Factor		1.601	1.601	1.601	1.601	1.601	1.601	1.601	1.601	1.601	1.601	1.601	1.601
8	Colstrip Tons	901,562	67,021	89,319	85,009	89,444	86,446	83,385	89,319	75,328	80,387	71,955	56,590	27,358
9	Cost/Ton	$10.89	$10.89	$10.89	$10.89	$10.89	$10.89	$10.89	$10.89	$10.89	$10.89	$10.89	$10.89	$10.89
10	Colstrip Fuel Cost	**$9,818,005**	$729,854	$972,686	$925,752	$974,046	$941,397	$908,067	$972,686	$820,321	$875,417	$783,590	$616,261	$297,928
11	Centralia MWh	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Conversion Factor		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
13	Centralia Tons	0	0	0	0	0	0	0	0	0	0	0	0	0
14	Cost/Ton		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
15	Centralia Fuel Cost	**$0**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
16	Kettle Falls MWh	295,200	18,700	31,900	30,400	32,000	32,000	27,000	32,500	22,900	25,900	18,600	17,600	5,700
17	Conversion Factor		0.599	0.599	0.599	0.599	0.599	0.599	0.599	0.599	0.599	0.599	0.599	0.599
18	Kettle Falls Tons	492,821	31,219	53,255	50,751	53,422	53,422	45,075	54,257	38,230	43,239	31,052	29,382	9,516
19	Cost/Ton	$7.51	$7.51	$7.51	$7.51	$7.51	$7.51	$7.51	$7.51	$7.51	$7.51	$7.51	$7.51	$7.51
20	Kettle Falls Fuel Cost	**$3,701,088**	$234,452	$399,948	$381,142	$401,202	$401,202	$338,514	$407,471	$287,110	$324,723	$233,199	$220,661	$71,464
21	Rathdrum MWh	193,400	0	1,500	39,700	56,400	41,100	25,400	29,300	0	0	0	0	0
22	Rathdrum Fuel Cost		$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35
23	Rathdrum Fuel Cost	**$5,482,890**	$0	$42,525	$1,125,495	$1,598,940	$1,165,185	$720,090	$830,655	$0	$0	$0	$0	$0
24	Total Fuel Expense	$19,001,983	$964,307	$1,415,159	$2,432,389	$2,974,188	$2,507,784	$1,966,671	$2,210,812	$1,107,431	$1,200,140	$1,016,789	$836,922	$369,392
25	Total Net Expense	$39,585,483	$3,230,207	$3,857,759	$5,404,089	$5,390,488	$3,868,084	$3,575,971	$4,124,112	$2,237,131	$3,250,240	$4,063,089	-$564,878	$1,149,192

AVISTA CORPORATION
JULY 2000 - JUNE 2001
OBLIGATIONS & RESOURCES - NORMALIZED

Line No.	LOADS & CONTRACT OBLIGATIONS - aMW													
1	Hours in Month	8,760	744	744	720	745	720	744	744	672	744	719	744	720
		AVERAGE	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01
2	NET SYSTEM LOAD	993	941	955	903	894	1,025	1,177	1,144	1,083	1,004	950	893	944
3	CHENEY	2	2	2	2	2	2	2	2	2	2	2	2	2
4	CLARK	120	145	65	69	65	98	122	163	163	163	152	102	127
5	COGENTRIX 57MO	100	100	100	100	100	100	100	100	100	100	100	100	100
6	EWEB	2	7	7	7	-	-	-	-	-	-	-	-	-
7	PACIFICORP 94 SALE	9	22	62	21	-	-	-	-	-	-	-	-	8
8	PACIFICORP EXCHANGE	3	7	15	15	-	-	-	-	-	-	-	-	1
9	PGE CAPACITY	44	42	46	42	44	44	40	44	45	44	44	46	44
10	SNOHOMISH 10-YR	71	50	57	100	100	100	50	50	50	100	100	50	50
11	PUGET2	63	75	75	75	75	75	75	50	50	50	50	50	50
12	PEND OREILLE	1	6	-	-	-	-	-	-	-	-	-	-	-
13	NICHOLS PUMPING	7	7	7	7	7	7	7	7	7	7	7	7	7
14	PGE2 YR	25	25	25	25	25	25	25	25	25	25	25	25	25
15	MONTANA-WIMP	100	100	100	100	100	100	100	100	100	100	100	100	100
16	ENTITLEMENT/SUP RETURN	1	1	1	1	1	1	1	1	1	1	1	1	1
17	CANADIAN ENTITLEMENT	1	1	1	1	1	1	1	1	1	1	1	1	1
18	**TOTAL OBLIGATIONS**	**1,541**	**1,531**	**1,519**	**1,468**	**1,414**	**1,577**	**1,700**	**1,687**	**1,626**	**1,597**	**1,532**	**1,377**	**1,459**
19	**CONTRACT RIGHTS - aMW**													
20	ESI-50 flat	50	50	50	50	50	50	50	50	50	50	50	50	50
21	BLACK CREEK HYDRO	1	-	11	-	-	-	-	-	-	-	-	-	-
22	SEMPRA-50 on-pk	19	-	29	28	28	28	27	28	29	29	-	-	-
23	CINERGY-25 on-pk	14	13	15	14	14	14	13	14	14	15	14	14	14
24	BPA 115MW-flat	115	115	115	115	115	115	115	115	115	115	115	115	115
25	ENRON 2-YR-50 flat	50	50	50	50	50	50	50	50	50	50	50	50	50
26	SMALL POWER	4	4	4	4	4	4	3	4	4	4	4	5	7
27	POTLATCH	54	57	59	44	57	56	59	57	57	57	59	50	37
28	UPRIVER	9	5	2	3	5	8	11	11	11	12	13	11	10
29	ENTITLEMENT/SUPPLEMENTAL	1	1	1	1	1	1	1	1	1	1	1	1	1
30	PGE Cap Rtn	44	42	46	42	44	44	40	44	45	44	44	46	44
31	IDAHO-WIMP	100	100	100	100	100	100	100	100	100	100	100	100	100
32	MIECO 2-YR	25	25	25	25	25	25	25	25	25	25	25	25	25
33	CSPE	5	5	5	5	5	5	5	5	5	5	5	5	5
34	PACIFICORP EXCHG RETURN	3	-	-	-	-	-	5	16	18	-	-	-	-
35	WNP-3	42	-	-	-	-	100	100	100	100	49	49	-	-
36	TRANSALTA	143	190	190	190	190	190	190	190	190	190	-	-	-
37	TOTAL CONTRACT RIGHTS	**678**	**657**	**702**	**671**	**688**	**790**	**794**	**810**	**814**	**746**	**529**	**472**	**458**
38	**HYDRO GENERATION**													
39	MID-COLUMBIA HYDRO	106	106	114	84	81	90	109	122	121	97	102	111	129
40	SYSTEM HYDRO	448	496	314.5	274	221	334	440	373	429	431	511	768	782
41	**THERMAL GENERATION**													
42	COLSTRIP	165	144	192	189	192	192	179	192	179	173	160	122	61
43	KETTLE FALLS	34	25	43	42	43	44	36	44	34	35	26	24	8
44	RATHDRUM	22	0	2	55	76	57	34	39	0	0	0	0	0
45	**TOTAL RESOURCES**	**1,451**	**1,428**	**1,368**	**1,315**	**1,301**	**1,507**	**1,592**	**1,580**	**1,577**	**1,482**	**1,328**	**1,497**	**1,438**
46	SHORT-TERM PURCHASES	100	103	151	153	113	70	108	107	49	115	204	0	21
47	SHORT-TERM SALES	10	0	0	0	0	0	0	0	0	0	0	120	0

BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-________

APPENDIX 14

Avista Corp.
Secondary Sales, Purchases and Thermal Generation
Estimated Expenses
July 2000 - June 2001

Line No.		Total	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01
1	Short-term Sales $ on-pk	$2,395,174	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,395,174	$0
2	Short-term Sales $ off-pk	$18,669,856	$3,000,580	$2,312,788	$358,202	$1,582,695	$1,509,930	$3,220,110	$57,918	$390,180	$0	$0	$3,648,262	$2,589,191
3	S-T Sales MWh-on-pk	52,069	0	0	0	0	0	0	0	0	0	0	52,069	0
4	S-T Sales MWh-off-pk	426,380	65,230	50,278	7,787	35,171	33,554	71,558	1,379	9,290	0	0	88,982	63,151
5	S-T Sales MWh Total	478,449	65,230	50,278	7,787	35,171	33,554	71,558	1,379	9,290	0	0	141,051	63,151
6	S-T Sales price-on-pk $/MWh *		$98.00	$107.00	$98.00	$70.00	$70.00	$70.00	$50.00	$47.00	$47.00	$46.00	$46.00	$46.00
7	S-T Sales price-off-pk $/MWh		$46.00	$46.00	$46.00	$45.00	$45.00	$45.00	$42.00	$42.00	$42.00	$41.00	$41.00	$41.00
8	Short-term Purchases $ on-pk	$49,573,543	$10,337,726	$8,100,114	$6,541,010	$5,123,790	$1,561,980	$4,068,330	$2,417,350	$1,597,154	$2,561,171	$4,819,052	$0	$2,445,86
9	Short-term Purchases $ off-pk	$1,500,169	$0	$0	$0	$0	$0	$0	$0	$0	$715,470	$784,699	$0	$0
10	S-T Purch MWh-on-pk	696,319	105,487	75,702	66,745	73,197	22,314	58,119	48,347	33,982	54,493	104,762	0	53,171
11	S-T Purch MWh-off-pk	36,174	0	0	0	0	0	0	0	0	17,035	19,139	0	0
12	S-T Purch MWh Total	732,493	105,487	75,702	66,745	73,197	22,314	58,119	48,347	33,982	71,528	123,901	0	53,171
13	S-T Purch price-on-pk $/MWh		$98.00	$107.00	$98.00	$70.00	$70.00	$70.00	$50.00	$47.00	$47.00	$46.00	$46.00	$46.00
14	S-T Purch price-off-pk $/MWh		$46.00	$46.00	$46.00	$45.00	$45.00	$45.00	$42.00	$42.00	$42.00	$41.00	$41.00	$41.00
15	Net Purchase Power Expense $	$30,008,682	$7,337,146	$5,787,326	$6,182,808	$3,541,095	$52,050	$848,220	$2,359,432	$1,206,974	$3,276,641	$5,603,751	-$6,043,436	-$143,325
16	Wtd Avg On-Pk Price $/MWh	$69.44												
17	Wtd Avg Off-Pk Price $/MWh	$43.61												
18	Colstrip MWh	1,612,800	142,848	142,848	138,240	143,040	138,240	142,848	142,848	129,024	142,848	138,048	142,848	69,120
19	Conversion Factor		1.601	1.601	1.601	1.601	1.601	1.601	1.601	1.601	1.601	1.601	1.601	1.601
20	Colstrip Tons	1,007,369	89,224	89,224	86,346	89,344	86,346	89,224	89,224	80,590	89,224	86,226	89,224	43,173
21	Cost/Ton	$10.89	$10.89	$10.89	$10.89	$10.89	$10.89	$10.89	$10.89	$10.89	$10.89	$10.89	$10.89	$10.89
22	Colstrip Fuel Cost	**$ 10,970,246**	$971,649	$971,649	$940,308	$972,956	$940,308	$971,649	$971,649	$877,625	$971,649	$939,001	$971,649	$470,154
23	Kettle Falls MWh	295,200	18,700	31,900	30,400	32,000	32,000	27,000	32,500	22,900	25,900	18,600	17,600	5,70
24	Conversion Factor		0.599	0.599	0.599	0.599	0.599	0.599	0.599	0.599	0.599	0.599	0.599	0.59
25	Kettle Falls Tons	492,820	31,219	53,255	50,751	53,422	53,422	45,075	54,257	38,230	43,239	31,052	29,382	9,516
26	Cost/Ton	$7.51	$7.51	$7.51	$7.51	$7.51	$7.51	$7.51	$7.51	$7.51	$7.51	$7.51	$7.51	$7.51
27	Kettle Falls Fuel Cost	**$ 3,701,078**	$234,455	$399,945	$381,140	$401,199	$401,199	$338,513	$407,470	$287,107	$324,725	$233,201	$220,659	$71,465
28	Rathdrum MWh	553,058	0	88,536	88,560	102,810	102,960	108,624	61,568	0	0	0	0	0
29	Rathdrum Fuel Cost	$43.84	$43.84	$43.84	$43.84	$43.84	$43.84	$43.84	$43.84					
30	Rathdrum Fuel Cost	**$ 24,246,061**	$0	$3,881,418	$3,882,470	$4,507,190	$4,513,766	$4,762,076	$2,699,141	$0	$0	$0	$0	$0
31	Total Fuel Expense	$38,917,385	$1,206,104	$5,253,012	$5,203,918	$5,881,345	$5,855,273	$6,072,238	$4,078,260	$1,164,732	$1,296,374	$1,172,202	$1,192,308	$541,619
32	Total Net Expense	$68,926,067	$8,543,250	$11,040,338	$11,386,726	$9,422,440	$5,907,323	$6,920,458	$6,437,692	$2,371,706	$4,573,015	$6,775,953	-$4,851,128	$398,294
33	Normalized Total Net Expense	$39,585,484	$3,230,207	$3,857,759	$5,404,089	$5,390,488	$3,868,084	$3,575,971	$4,124,112	$2,237,131	$3,250,240	$4,063,089	-$564,878	$1,149,192
34	Increased Total Net Expense	$29,340,583	$5,313,043	$7,182,579	$5,982,637	$4,031,952	$2,039,239	$3,344,487	$2,313,580	$134,575	$1,322,775	$2,712,864	-$4,286,250	-$750,898

* Prices as of 6-16-2000

AVISTA CORPORATION
JULY 2000 - JUNE 2001
OBLIGATIONS & RESOURCES

Line No.	LOADS & CONTRACT OBLIGATIONS - aMW	AVERAGE	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01
1	Hours in Month	8,760	744	744	720	745	720	744	744	672	744	719	744	720
2	NET SYSTEM LOAD	993	941	955	903	894	1,025	1,177	1,144	1,083	1,004	950	893	944
3	CHENEY	2	2	2	2	2	2	2	2	2	2	2	2	2
4	CLARK	120	145	65	69	65	98	122	163	163	163	152	102	127
5	COGENTRIX 57MO	100	100	100	100	100	100	100	100	100	100	100	100	100
6	EWEB	2	7	7	7	-	-	-	-	-	-	-	-	-
7	PACIFICORP 94 SALE	9	22	62	21	-	-	-	-	-	-	-	-	8
8	PACIFICORP EXCHANGE	3	7	15	15	-	-	-	-	-	-	-	-	1
9	PGE CAPACITY	44	42	46	42	44	44	40	44	45	44	44	46	44
10	SNOHOMISH 10-YR	71	50	57	100	100	100	50	50	50	100	100	50	50
11	PUGET2	63	75	75	75	75	75	75	50	50	50	50	50	50
12	PEND OREILLE	1	6	-	-	-	-	-	-	-	-	-	-	-
13	NICHOLS PUMPING	7	7	7	7	7	7	7	7	7	7	7	7	7
14	PGE2 YR	25	25	25	25	25	25	25	25	25	25	25	25	25
15	MONTANA-WIMP	100	100	100	100	100	100	100	100	100	100	100	100	100
16	ENTITLEMENT/SUP RETURN	1	1	1	1	1	1	1	1	1	1	1	1	1
17	CANADIAN ENTITLEMENT	1	1	1	1	1	1	1	1	1	1	1	1	1
18	**TOTAL OBLIGATIONS**	**1,541**	**1,531**	**1,519**	**1,468**	**1,414**	**1,577**	**1,700**	**1,687**	**1,626**	**1,597**	**1,532**	**1,377**	**1,459**
19	**CONTRACT RIGHTS - aMW**													
20	ESI-50 flat	50	50	50	50	50	50	50	50	50	50	50	50	50
21	BLACK CREEK HYDRO	1	-	11	-	-	-	-	-	-	-	-	-	-
22	SEMPRA-50 on-pk	19	-	29	28	28	28	27	28	29	29	-	-	-
23	CINERGY-25 on-pk	14	13	15	14	14	14	13	14	14	15	14	14	14
24	BPA 115MW-flat	115	115	115	115	115	115	115	115	115	115	115	115	115
25	ENRON 2-YR-50 flat	50	50	50	50	50	50	50	50	50	50	50	50	50
26	SMALL POWER	4	4	4	4	4	4	3	4	4	4	4	5	7
27	POTLATCH	54	57	59	44	57	56	59	57	57	57	59	50	37
28	UPRIVER	9	5	2	3	5	8	11	11	11	12	13	11	10
29	ENTITLEMENT/SUPPLEMENTAL	1	1	1	1	1	1	1	1	1	1	1	1	1
30	PGE Cap Rtn	44	42	46	42	44	44	40	44	45	44	44	46	44
31	IDAHO-WIMP	100	100	100	100	100	100	100	100	100	100	100	100	100
32	MIECO 2-YR	25	25	25	25	25	25	25	25	25	25	25	25	25
33	CSPE	5	5	5	5	5	5	5	5	5	5	5	5	5
34	PACIFICORP EXCHG RETURN	3	-	-	-	-	-	5	16	18	-	-	-	-
35	WNP-3	42	-	-	-	-	100	100	100	100	49	49	-	-
36	TRANSALTA	143	190	190	190	190	190	190	190	190	190	-	-	-
37	TOTAL CONTRACT RIGHTS	**678**	**657**	**702**	**671**	**688**	**790**	**794**	**810**	**814**	**746**	**529**	**472**	**458**
38	**HYDRO GENERATION**													
39	MID-COLUMBIA HYDRO	106	106	114	84	81	90	109	122	121	97	102	111	129
40	SYSTEM HYDRO	448	496	315	274	221	334	440	373	429	431	511	768	782
41	**THERMAL GENERATION**													
42	COLSTRIP	184	192	192	192	192	192	192	192	192	192	192	192	96
43	KETTLE FALLS	34	25	43	42	43	44	36	44	34	35	26	24	8
44	RATHDRUM	63	0	119	123	138	143	146	83	0	0	0	0	0
45	**TOTAL RESOURCES**	**1,511**	**1,477**	**1,484**	**1,386**	**1,363**	**1,593**	**1,718**	**1,624**	**1,589**	**1,501**	**1,360**	**1,567**	**1,473**
46	SHORT-TERM PURCHASES	49	54	35	82	51	0	0	63	37	96	172	0	0
47	SHORT-TERM SALES	20	0	0	0	0	16	18	0	0	0	0	190	14

AVISTA CORP
JULY 2000 - JUNE 2001
TOTAL OBLIGATIONS

OBLIGATIONS ON-PEAK - MWh

On-Peak Hours in Month	4,912	400	432	400	416	400	400	416	384	432	400	416	416
	TOTAL	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01
NATIVE LOADS-RATE CASE	5,339,850	441,066	447,628	403,099	426,259	435,420	534,170	510,682	429,388	448,186	430,322	398,635	434,995
CHENEY	9,824	800	864	800	832	800	800	832	768	864	800	832	832
CLARK	899,648	89,200	43,200	42,400	41,600	60,000	74,800	104,000	96,000	108,000	93,600	65,312	81,536
COGENTRIX 57MO	491,200	40,000	43,200	40,000	41,600	40,000	40,000	41,600	38,400	43,200	40,000	41,600	41,600
EWEB	12,320	4,000	4,320	4,000				-	-	-	-	-	-
PACIFICORP 94 SALE	82,800	16,170	46,200	15,030				-	-	-	-	-	5,400
PACIFICORP EXCHANGE	27,600	5,208	11,160	10,800				-	-	-	-	-	432
PGE CAPACITY	384,000	31,500	34,500	30,000	33,000	31,500	30,000	33,000	30,000	33,000	31,500	34,500	31,500
SNOHOMISH 10-YR	465,608	37,200	42,408	40,000	41,600	40,000	37,200	37,200	33,600	43,200	40,000	37,200	36,000
PUGET2	368,000	40,000	43,200	40,000	41,600	40,000	40,000	20,800	19,200	21,600	20,000	20,800	20,800
PEND OREILLE	2,400	2,400						-	-	-	-	-	-
NICHOLS PUMPING	34,384	2,800	3,024	2,800	2,912	2,800	2,800	2,912	2,688	3,024	2,800	2,912	2,912
PGE2 YR	122,800	10,000	10,800	10,000	10,400	10,000	10,000	10,400	9,600	10,800	10,000	10,400	10,400
MONTANA-WIMP	491,200	40,000	43,200	40,000	41,600	40,000	40,000	41,600	38,400	43,200	40,000	41,600	41,600
ENTITLEMENT/SUP RETURN	1,560	140	134	140	122	140	140	140	80	170	110	140	104
CANADIAN ENTITLEMENT	4,912	400	432	400	416	400	400	416	384	432	400	416	416
TOTAL OBLIGATIONS ON-PEAK	8,738,106	760,884	774,270	679,469	681,941	701,060	810,310	803,582	698,508	755,676	709,532	654,347	708,527

OBLIGATIONS OFF-PEAK - MWh

Off-Peak Hours in Month	3,848	344	312	320	329	320	344	328	288	312	319	328	304
	TOTAL	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01
NATIVE LOADS-RATE CASE	3,353,663	259,038	262,892	247,061	239,771	302,580	341,518	340,454	298,388	298,790	252,729	265,757	244,685
CHENEY	7,696	688	624	640	658	640	688	656	576	624	638	656	608
CLARK	143,234	18,643	5,160	7,208	6,825	10,200	15,633	16,900	13,200	12,900	15,760	10,613	10,192
COGENTRIX 57MO	384,800	34,400	31,200	32,000	32,900	32,000	34,400	32,800	28,800	31,200	31,900	32,800	30,400
EWEB	3,136	1,208	888	1,040	-	-	-	-	-	-	-	-	-
PACIFICORP 94 SALE	-	-	-	-	-	-	-	-	-	-	-	-	-
PACIFICORP EXCHANGE	-	-	-	-	-	-	-	-	-	-	-	-	-
PGE CAPACITY	-	-	-	-	-	-	-	-	-	-	-	-	-
SNOHOMISH 10-YR	160,000	0	0	32,000	32,900	32,000	0	-	-	31,200	31,900	0	0
PUGET2	180,350	15,800	12,600	14,000	14,200	14,000	15,800	16,400	14,400	15,600	15,950	16,400	15,200
PEND OREILLE	2,064	2,064	0	0	0	0	0	-	-	-	-	-	-
NICHOLS PUMPING	26,936	2,408	2,184	2,240	2,303	2,240	2,408	2,296	2,016	2,184	2,233	2,296	2,128
PGE2 YR	96,200	8,600	7,800	8,000	8,225	8,000	8,600	8,200	7,200	7,800	7,975	8,200	7,600
MONTANA-WIMP	384,800	34,400	31,200	32,000	32,900	32,000	34,400	32,800	28,800	31,200	31,900	32,800	30,400
ENTITLEMENT/SUP RETURN	7,770	640	676	640	658	640	640	640	640	640	640	640	676
CANADIAN ENTITLEMENT	3,848	344	312	320	329	320	344	328	288	312	319	328	304
TOTAL OBLIGATIONS OFF-PEAK	4,754,497	378,233	355,536	377,149	371,669	434,620	454,431	451,474	394,308	432,450	391,944	370,490	342,193
TOTAL OBLIGATIONS - MWH	13,492,603	1,139,117	1,129,806	1,056,618	1,053,610	1,135,680	1,264,741	1,255,056	1,092,816	1,188,126	1,101,476	1,024,837	1,050,720
TOTAL OBLIGATIONS - AMW	1,541	1,531	1,519	1,468	1,414	1,577	1,700	1,687	1,626	1,597	1,532	1,377	1,459

AVISTA CORP
TOTAL RESOURCES
JULY 2000 - JUNE 2001

RESOURCES ON-PEAK-MWh

On-Peak Hours in Month	4,912	400	432	400	416	400	400	416	384	432	400	416	416
	TOTAL	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01
ESI-50 flat	245,600	20,000	21,600	20,000	20,800	20,000	20,000	20,800	19,200	21,600	20,000	20,800	20,800
BLACK CREEK HYDRO	4,752		4,752										
SEMPRA-50 on-pk	164,000		21,600	20,000	20,800	20,000	20,000	20,800	19,200	21,600			
CINERGY-25 on-pk	122,800	10,000	10,800	10,000	10,400	10,000	10,000	10,400	9,600	10,800	10,000	10,400	10,400
BPA 115MW-flat	564,880	46,000	49,680	46,000	47,840	46,000	46,000	47,840	44,160	49,680	46,000	47,840	47,840
ENRON 2-YR-50 flat	245,600	20,000	21,600	20,000	20,800	20,000	20,000	20,800	19,200	21,600	20,000	20,800	20,800
SMALL POWER	20,912	1,600	1,728	1,600	1,664	1,600	1,200	1,664	1,536	1,728	1,600	2,080	2,912
POTLATCH	289,808	23,600	25,488	23,600	24,544	23,600	23,600	24,544	22,656	25,488	23,600	24,544	24,544
UPRIVER	41,664	2,000	864	1,200	2,080	3,200	4,400	4,576	4,224	5,184	5,200	4,576	4,160
ENTITLEMENT & SUPPLE(1)	9,330	780	810	780	780	780	780	780	720	810	750	780	780
PGE Cap Rtn	-	0	0	0	0	0	0	-	-	-	-	-	-
IDAHO-WIMP	491,200	40,000	43,200	40,000	41,600	40,000	40,000	41,600	38,400	43,200	40,000	41,600	41,600
MIECO 2-YR	122,800	10,000	10,800	10,000	10,400	10,000	10,000	10,400	9,600	10,800	10,000	10,400	10,400
CSPE	40,743	3,150	3,645	3,600	3,744	3,600	3,600	3,276	3,024	3,402	3,150	3,276	3,276
PACIFICORP EXCHG RETURN	27,600						3,720	11,904	11,976				
WNP-3	170,355					30,750	30,750	31,980	29,520	16,605	30,750		
MID-COLUMBIA HYDRO	575,948	48,881	55,130	39,888	38,591	40,176	47,839	56,246	50,400	44,714	46,232	51,187	56,664
SYSTEM HYDRO	2,815,492	258,986	191,431	156,456	130,077	181,440	241,502	208,841	217,526	239,940	253,088	370,661	365,544
TRANSALTA	699,200	76,000	82,080	76,000	79,040	76,000	76,000	79,040	72,960	82,080	-	-	-
COLSTRIP	903,168	76,800	82,944	76,800	79,872	76,800	76,800	79,872	73,728	82,944	76,800	79,872	39,936
KETTLE FALLS	202,820	17,600	19,008	17,600	18,304	17,600	17,600	18,304	16,896	19,008	17,600	17,600	5,700
RATHDRUM	335,184	0	51,408	49,200	57,408	57,200	58,400	61,568	0	0	0	0	0
TOTAL RESOURCES ON-PEAK	8,093,856	655,397	698,568	612,724	608,744	678,746	752,191	755,235	664,526	701,183	604,770	706,416	655,356

RESOURCES OFF-PEAK-MWh

Off-Peak Hours in Month	3,848	344	312	320	329	320	344	328	288	312	319	328	304
	TOTAL	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01
ESI-50 flat	192,400	17,200	15,600	16,000	16,450	16,000	17,200	16,400	14,400	15,600	15,950	16,400	15,200
BLACK CREEK HYDRO	3,432		3,432										
SEMPRA-50 on-pk	-	-	-	-	-	-	-						
CINERGY-25 on-pk	-	-	-	-	-	-	-						
BPA 115MW-flat	442,520	39,560	35,880	36,800	37,835	36,800	39,560	37,720	33,120	35,880	36,685	37,720	34,960
ENRON 2-YR-50 flat	192,400	17,200	15,600	16,000	16,450	16,000	17,200	16,400	14,400	15,600	15,950	16,400	15,200
SMALL POWER	16,288	1,376	1,248	1,280	1,316	1,280	1,032	1,312	1,152	1,248	1,276	1,640	2,128
POTLATCH	184,238	18,808	18,408	8,080	17,921	16,720	20,296	17,864	15,648	16,920	18,821	12,656	2,096
UPRIVER	32,608	1,720	624	960	1,645	2,560	3,784	3,608	3,168	3,744	4,147	3,608	3,040
ENTITLEMENT & SUPP	-	0	0	0	0	0	0						
PGE Cap Rtn	384,000	31,500	34,500	30,000	33,000	31,500	30,000	33,000	30,000	33,000	31,500	34,500	31,500
IDAHO-WIMP	384,800	34,400	31,200	32,000	32,900	32,000	34,400	32,800	28,800	31,200	31,900	32,800	30,400
MIECO 2-YR	96,200	8,600	7,800	8,000	8,225	8,000	8,600	8,200	7,200	7,800	7,975	8,200	7,600
CSPE	3,076	570	75	-	-	-	120	444	336	318	445	444	324
PACIFICORP EXCHG RETURN	-	0	0	0	0	0	0						
WNP-3	189,332					41,250	43,650	42,420	37,680	19,851	4,481		
MID-COLUMBIA HYDRO	347,503	29,983	29,686	20,592	21,754	24,624	33,257	34,522	30,912	27,454	27,106	31,397	36,216
SYSTEM HYDRO	1,105,590	110,038	42,557	40,824	34,568	59,040	85,858	68,671	70,762	80,724	114,321	200,731	197,496
TRANSALTA	550,430	65,360	59,280	60,800	62,510	60,800	65,360	62,320	54,720	59,280	-	-	-
COLSTRIP	709,632	66,048	59,904	61,440	63,168	61,440	66,048	62,976	55,296	59,904	61,248	62,976	29,184
KETTLE FALLS	92,380	1,100	12,892	12,800	13,696	14,400	9,400	14,196	6,004	6,892	1,000	0	0
RATHDRUM	217,874	0	37,128	39,360	45,402	45,760	50,224	0	0	0	0	0	0
TOTAL RESOURCES OFF-PEAK	5,144,703	443,463	405,814	384,936	406,840	468,174	525,989	452,853	403,598	415,415	372,805	459,472	405,344

TOTAL RESOURSE - MWH	13,238,559	1,098,860	1,104,382	997,660	1,015,584	1,146,920	1,278,180	1,208,088	1,068,124	1,116,598	977,575	1,165,888	1,060,700
TOTAL RESOURSE - AMW	1,511	1,477	1,484	1,386	1,363	1,593	1,718	1,624	1,589	1,501	1,360	1,567	1,473

AVISTA CORP
JULY 2000 - JUNE 2001
THERMAL GENERATION

	TOTAL	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01
ON-PK HOURS IN MONTH	4,912	400	432	400	416	400	400	416	384	432	400	416	416
OFF-PK HOURS IN MONTH	3,848	344	312	320	329	320	344	328	288	312	319	328	304
	8,760	744	744	720	745	720	744	744	672	744	719	744	720
COLSTRIP													
CAPABILITY - MW		222	222	222	222	222	222	222	222	222	222	222	222
AVAILABILITY		0.866	0.866	0.866	0.866	0.866	0.866	0.866	0.866	0.866	0.866	0.866	0.433
AMW		192	192	192	192	192	192	192	192	192	192	192	96
ON-PK MWH	903,168	76,800	82,944	76,800	79,872	76,800	76,800	79,872	73,728	82,944	76,800	79,872	39,936
OFF-PK MWH	709,632	66,048	59,904	61,440	63,168	61,440	66,048	62,976	55,296	59,904	61,248	62,976	29,184
TOTAL MWH	1,612,800	142,848	142,848	138,240	143,040	138,240	142,848	142,848	129,024	142,848	138,048	142,848	69,120
KETTLE FALLS													
CAPABILITY - MW		46	46	46	46	46	46	46	46	46	46	46	46
AVAILABILITY		0.965	0.965	0.965	0.965	0.965	0.965	0.965	0.965	0.965	0.965	0.965	0.311
AMW		44	44	44	44	44	44	44	44	44	44	44	14
NORMALIZED - MWH	295,200	18,700	31,900	30,400	32,000	32,000	27,000	32,500	22,900	25,900	18,600	17,600	5,700
ON-PK MWH	202,820	17,600	19,008	17,600	18,304	17,600	17,600	18,304	16,896	19,008	17,600	17,600	5,700
OFF-PK MWH	92,380	1,100	12,892	12,800	13,696	14,400	9,400	14,196	6,004	6,892	1,000	-	-
TOTAL MWH	295,200	18,700	31,900	30,400	32,000	32,000	27,000	32,500	22,900	25,900	18,600	17,600	5,700
RATHDRUM													
CAPABILITY - MW		141	142	146	164	170	174	176	172	168	163	160	144
AVAILABILITY			0.84	0.84	0.84	0.84	0.84	0.84					
AMW		0	119	123	138	143	146	148	0	0	0	0	0
DELIVERED GAS COST - as of 6-20-00		$3.88	$3.88	$3.88	$3.88	$3.88	$3.88	$3.88					
HEAT RATE		11,300	11,300	11,300	11,300	11,300	11,300	11,300	11,300	11,300	11,300	11,300	11,300
INCREMENTAL FUEL COST - $/MWH		$43.84	$43.84	$43.84	$43.84	$43.84	$43.84	$43.84	$0.00	$0.00	$0.00	$0.00	$0.00
ON-PEAK MARKET PRICE		$98.00	$107.00	$98.00	$70.00	$70.00	$70.00	$50.00	$47.00	$47.00	$46.00	$46.00	$46.00
OFF-PEAK MARKET PRICE		$46.00	$46.00	$46.00	$45.00	$45.00	$45.00	$42.00	$42.00	$42.00	$41.00	$41.00	$41.00
ON-PK MWH	335,184	-	51,408	49,200	57,408	57,200	58,400	61,568	-	-	-	-	-
OFF-PK MWH	217,874	-	37,128	39,360	45,402	45,760	50,224	-	-	-	-	-	-
TOTAL MWH	553,058	-	88,536	88,560	102,810	102,960	108,624	61,568	-	-	-	-	-

Short-Term Market Price

The market price related to short-term purchases and sales would be based on Avista's actual on-peak and off-peak short-term (one-year and less) energy purchases and sales related to the Company's system resources and obligations. Four energy prices would be calculated each month as follows:

On-Peak Purchase Price = $\dfrac{\text{Total Short-Term On-Peak Purchase Dollars}}{\text{Total Short-Term On-Peak Purchase MWH}}$

Off-Peak Purchase Price = $\dfrac{\text{Total Short-Term Off-Peak Purchase Dollars}}{\text{Total Short-Term Off-Peak Purchase MWH}}$

On-Peak Sales Price = $\dfrac{\text{Total Short-Term On-Peak Sales Dollars}}{\text{Total Short-Term On-Peak Sales MWH}}$

Off-Peak Sales Price = $\dfrac{\text{Total Short-Term Off-Peak Sales Dollars}}{\text{Total Short-Term Off-Peak Sales MWH}}$

Deficiencies during on-peak and off-peak hours would be priced at the On-Peak Purchase Price and the Off-Peak Purchase Price, respectively. Short-term surplus energy for on-peak and off-peak hours would be priced at the On-Peak Sales Price and the Off-Peak Sales Price, respectively.

Thermal Generation

The generation at Colstrip, Kettle Falls, Rathdrum and Northeast Turbine would be based on the actual on-peak and off-peak generation during the month, per the Company's actual records. The fuel expenses for each plant would be based on the actual fuel costs for the month. Fuel costs would exclude non-recurring expenses such as inventory adjustments, and other prior period adjustments. The fuel costs for Rathdrum and Northeast would reflect total fuel costs, including commodity costs and transportation expenses.

Hydroelectric Generation

Hydroelectric generation would be based on the actual on-peak and off-peak generation during the month, per the Company's actual records.

BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-________

APPENDIX 15

BEFORE THE
WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

Petition of	)	
	)	
AVISTA CORPORATION	)	
	)	
For an Order Regarding the Accounting	)	Docket No. UE-________
Treatment of Certain Wholesale	)	
Power Costs to Serve Firm Load	)	ORDER (PROPOSED)
Obligations	)	

On June 23, 2000, Avista Corporation ("Avista" or "Company") filed a Petition with this Commission under WAC 480-09-420(7) seeking an order authorizing the deferral of certain power costs related to the recent dramatic increase in short-term wholesale market prices. As explained by the Company in its Petition, short-term market prices have risen to unprecedented levels and have caused a comparable dramatic increase in power supply expenses for the Company. The Company requests an order which authorizes the deferral of certain power supply costs beginning July 1, 2000 and ending June 30, 2001. The first deferral would occur in August 2000 for power costs incurred during the month of July 2000. The Company proposes to amortize the deferred costs over a ten-year period beginning July 1, 2001, with a carrying cost, equal to the Company's authorized rate of return, on the unamortized balance.

In its Petition the Company states that if the Commission approves the Company's request for a Power Cost Adjustment (PCA) in its General Rate Case proceeding, Docket No. UE-991606, the Company proposes that the monthly deferrals requested in its Petition end on the effective date of the PCA. The Company proposes that the balance of costs deferred under its Petition be rolled into the PCA mechanism for ratemaking purposes. The Company's Petition further states that if the Commission determines that the ratemaking treatment for the extraordinary power costs should not be included in the PCA mechanism, the Company proposes that the costs be amortized over a ten-year period.

The Company states that it has been the practice of the Commission to provide deferred accounting treatment and rate recovery for costs that are considered to be extraordinary, abnormal, unusual, or unpredictable and highly variable. The Company states that it believes that the power supply costs identified in its Petition qualify under all of these terms. The Company requests an accounting order authorizing it to defer the increased power supply costs as a regulatory asset to consider for later recovery in rates.

In its Petition the Company states that historical monthly market prices for the last 15 years have ranged from a low of 0.8¢ to a high of 4.0¢/KWH. Current monthly market prices are as high as 13.0¢/KWH. Daily prices have reached 37.5¢/KWH and hourly prices have frequently risen to 75.0¢/KWH. The Company estimates that short-term prices for July through December 2000 will cause an increase in power supply costs of approximately $29 million on a system basis ($20 million for the Washington jurisdiction). A $29 million increase in costs to the Company would equal an adverse earnings impact to the Company of approximately $0.40 per common share. This represents a significant impact to the utility when compared with total earnings for the utility in 1999 of $1.00/share and $0.88/share in 1998.

In its Petition the Company states that the specific power costs included for deferral would be limited to three power cost variables including short-term market prices, the related impacts on thermal generation, and hydroelectric generation. The Company proposes a twelve-month deferral period to capture the seasonal impacts that can occur over the course of a full year.

The Company sets forth the deferred accounting proposal in its Petition. The proposal includes the deferral of power costs, the recording of deferred income taxes and the inclusion of a carrying charge. The carrying charge is proposed to be the Company's authorized rate of return applied to the unamortized balance of deferred power costs.

FINDINGS

THE COMMISSION FINDS:

1. Avista is a public service company furnishing electric and natural gas service in the State of Washington and is subject to the regulatory authority of the Commission as to its rates, service, facilities and practices.

2. On June 23, 2000, Avista filed with the Commission a Petition to defer certain power supply costs associated with the recent dramatic increase in short-term wholesale market prices.

3. The deferral treatment proposed by Avista is reasonable and should be approved.

ORDER

WHEREFORE, THE COMMISSION HEREBY ORDERS:

1. Authorization is hereby given to Avista to defer certain power supply costs, as explained in the Company's Petition, associated with the dramatic increase in short-term wholesale market prices. The period for deferrals shall begin July 1, 2000 and end June 30, 2001. The deferred costs shall be amortized over a ten-year period beginning July 1, 2001, with a carrying cost, equal to the Company's authorized rate of return, on the unamortized balance.

2. The deferred power supply costs shall be treated as a regulatory asset and considered for later recovery in rates. Income taxes shall be normalized.

3. If the PCA mechanism proposed in Docket No. UE-991606 is adopted by the Commission, the monthly deferrals related to this Petition shall end on the effective date

of the PCA. The balance of costs deferred related to this Petition shall be rolled into the PCA mechanism for ratemaking purposes.

4. The Company shall prepare and submit monthly reports related to the power supply cost deferrals.

5. Nothing herein shall be construed to waive or otherwise impair the jurisdiction of the Commission over the rates, services, accounts and practices of Avista. The Commission, under its general ratemaking authority, will have the ability in subsequent proceedings to evaluate the reasonableness of the Company's power supply cost deferrals.

6. The Commission retains jurisdiction to effectuate the provisions of this Order.

DATED at Olympia, Washington and effective this __ day of July, 2000.

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

MARILYN SHOWALTER, Chairwoman

RICHARD HEMSTAD, Commissioner

WILLIAM R. GILLIS, Commissioner