Conley E. Ward [ISB No. 1683]
GIVENS PURSLEY LLP
601 W. Bannock Street
P.O. Box 2720
Boise, ID 83701-2720
Telephone No. (208) 388-1200
Fax No. (208) 388-1300
cew@givenspursley.com

Attorneys for Micron Technology, Inc.
S:\CLIENTS\4489\17\Direct Testimony of Dennis E. Peseau.DOC

RECEIVED [X]
FILED [ ]
2004 FEB 19 PM 4:43
IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS INTERIM AND BASE RATES AND CHARGES FOR ELECTRIC SERVCE	Case No. IPC-E-03-13

DIRECT TESTIMONY

OF

DENNIS E. PESEAU

ON BEHALF OF

MICRON TECHNOLOGY, INC.

ORIGINAL

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dennis E. Peseau. My business address is Suite 250, 1500 Liberty Street, S.E., Salem, Oregon 97302.

Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am the President of Utility Resources, Inc. ("URI"). URI has consulted on a number of economic, financial and engineering matters for various private and public entities for more than twenty years.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My resume is attached as Exhibit No. 1.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION?

A. Yes, on many occasions.

Q. FOR WHOM ARE YOU APPEARING IN THIS CASE?

A. I am appearing on behalf of Micron Technology, Inc ("Micron").

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. Micron has asked me to review Idaho Power Company's application and make such recommendations to the Commission as I believe appropriate.

Q. PLEASE PROVIDE A SUMMARY OF THE RECOMMENDATIONS YOU WILL BE MAKING IN THIS TESTIMONY.

A. The first part of my testimony addresses two revenue requirement issues. I will first explain why the Company's filing results in a mismatch of revenues and expenses and suggest two alternative methods of correcting this mismatch. I will also discuss Idaho Power's cost of capital recommendation and point out the ways in which it is overstated.

The second portion of my testimony deals with Idaho Power's class cost of service studies and the Company's rate spread recommendations. I will propose some changes to the cost of service study and recommend a method of eliminating the existing subsidy of the irrigation class of customers.

Q. BEFORE WE TURN TO THESE ISSUES, ARE THERE ANY GENERAL OBSERVATIONS YOU WOULD LIKE TO MAKE ABOUT THE COMPANY'S FILING IN THIS CASE?

A. Yes. As the Commission is well aware, Idaho Power used a "hybrid" 2003 test year in this case. That is, the Company used approximately 6 months of actual test year data and 6 months of estimated or budgeted data. The Commission has allowed this type of rate case presentation in the past, although it has generally been viewed as a second best alternative to be used only when severe inflation makes "regulatory lag" a serious problem. I have some reservations about the use of this methodology in today's low inflation environment. But my reason for drawing the Commission's attention to the hybrid test year is not to protest its use in this case, but rather to explain how it will complicate the proceedings and change the nature of the Commission's deliberations.

Q. HOW DOES A HYBRID TEST YEAR COMPLICATE THE PROCEEDINGS?

A. In two ways. First, when actual figures for the second half of the year are substituted for estimates, the Staff will have to conduct what amounts to a second audit to confirm that the changes are appropriately made. No other party has the resources to conduct this "trust, but verify" exercise, so it obviously increases the burden on the Staff, as well as all parties' reliance on their diligence.

The second complicating factor is that some of the adjustments proposed by the Staff and Intervenors cannot be quantified with precision because the "base case" that we are working with will presumably change when all the final numbers are in. This is apt to create some confusion during the hearings, and the Commission may want to give some thought to how to incorporate into the evidentiary record the true-up revisions to both the Company's base case and the Staff and Intervenors' adjustments.

Revenue Requirement Issues

Q. LET'S TURN NOW TO THE MERITS OF THE CASE. YOU EARLIER STATED THAT IDAHO POWER'S CASE IN CHIEF CONTAINS A MISMATCH OF REVENUES AND EXPENSES. PLEASE EXPLAIN WHAT YOU MEAN BY THE WORD "MISMATCH."

A. Idaho Power calculates its test year revenues in a straightforward manner. For the first six months of the test year, actual data is used. Projections are employed for the last six months. These projections will ultimately be replaced by actual figures before the close of the proceedings. Thus, by the end of the proceedings, test year revenues will consist of 2003 actual figures, "normalized" for weather and other standard adjustments.

On the other side of the ledger, expenses and rate base are treated in a much different manner. Again the Company uses six months of actual data and six months of projections. But it then goes on to annualize operating and maintenance expenses and rate base to year-end levels. In effect, this annualization treats these costs as if year-end levels had been in effect throughout the test year. This is a clear mismatch of revenues and expenses because revenues are "centered" on June 30, 2003, while rate base and expenses are centered on December 31, 2003.

To make this mismatch worse, Idaho Power further adds allegedly "known and measurable changes" in rate base and expenses that it forecasts for the period from January 1, 2004 through May 31, 2004. These adjustments include rate base additions of $18,165,002, operating and maintenance increases of $9,907,923, associated depreciation increases of $447.375, and an adjustment for a 2004 increase in depreciation rates totaling $5,976,270.

The net effect looks very much like a partially projected test year ending on May 31, 2004 for rate base and expenses, matched against revenues centered on June 30, 2003. The resulting mismatch overstates Idaho Power's revenue requirement and is not defensible.

Q. HOW SHOULD THIS MISMATCH BE CORRECTED?

A. There are basically two alternative remedies available. The first would be to reverse the annualizing entries and properly match test year averages on both sides of the ledger. The second alternative is to annualize revenues in the same manner as rate base and expenses.

Q. DO YOU HAVE A PREFERENCE BETWEEN THESE TWO ALTERNATIVES?

A. On the whole, I think annualizing revenues to 2003 year-end levels is the preferable course for two reasons. First, it is much simpler to annualize revenues than to back out Idaho Power's annualizing adjustments from numerous cost and rate base categories. Moreover, annualizing revenues produces a more forward-looking result than reversing the expense and rate base annualizations.

I recognize, however, that when faced with a similar mismatch problem in the last Idaho Power rate case, the Commission ordered a reversal of the improper annualization of expenses. Order No. 25880, pp. 3-4. In theory this course of action is equally acceptable, but it poses a greater risk of computational errors just because of the number of adjustments required. Consequently, I continue to recommend annualizing earnings instead.

Q. HAVE YOU CALCULATED AN APPROPRIATE ANNUALIZATION ADJUSTMENT FOR TEST YEAR REVENUES?

A. Assuming a revenue growth rate of 4.06%, annualizing revenues to year-end levels would add $9,731,765 to Idaho Power's test year revenues. This provides an accurate match between revenues and rate base and expenses.

Q. SHOULD IDAHO POWER'S PROPOSED 2004 KNOWN AND MEASURABLE CHANGES BE ADDED TO THE TEST YEAR BASE CASE?

A. Only in part. Adding known and measurable changes to a test year base case is a legitimate regulatory tool, but it must be used with extreme caution because of the high potential for abuse. Post-test year adjustments should only be accepted when they are in fact truly known and measurable. In order to qualify, a proposed adjustment must be virtually certain to occur, and its revenue requirement impact must be precisely and reliably quantifiable.

Only one of Idaho Power's proposed adjustments meets this test. The 2004 increase in depreciation rates is in fact certain to occur, and its impact on revenue requirements can be quantified down to the penny. This $5,976,220 known and measurable adjustment should be accepted. The other proposed adjustments should be rejected.

Q. WHAT IS YOUR RATIONALE FOR REJECTING THE REMAINING ADJUSTMENTS?

A. The other proposed adjustments fall into two separate categories. Of the $9,907,923 of known and measurable changes to operations and maintenance costs, $5,114,821 is for a 7% incentive pay package to be implemented in 2004. My understanding is that this incentive package is over and above normal pay increases, and is designed as a reward for cost savings to be realized as a result of extraordinary employee efforts.

The first problem, of course, is that this is not truly a <u>known</u> change because the incentive will presumably not be paid if the savings don't actually materialize. Furthermore, this type of incentive pay makes no sense unless it results in savings that exceed the incentive pay, in which case there is no need to further reward the Company for a program that will be essentially self funding. In fact, if the incentive pay program is successful, the net effect should be a reduction, rather than an increase, in Idaho Power's revenue requirement.

Thus, this adjustment fails both elements of the test. It is far from certain to occur, and its net impact on revenue requirements is impossible to quantify, and in fact could as easily be positive as negative.

Q. PLEASE EXPLAIN WHY THE REMAINING GROUP OF ADJUSTMENTS SHOULD BE DISALLOWED.

A. The remaining proposed adjustments are essentially projected or budgeted increases in rate base (with associated depreciation) and operating and maintenance expenses. These projections fail the known and measurable test on a number of grounds.

In the first place, they are not sufficiently certain to occur. If budgeted figures were deemed sufficiently reliable for ratemaking purposes, the Commission would presumable accept a fully projected test year. But to the best of my knowledge, the Idaho Commission has never accepted a fully projected test year because of the inherent untrustworthiness of projected figures.

Second, the net revenue requirement impact of these budgeted 2004 expenditures is unknown because Idaho Power has focused on only one side of the cost-benefit equation. Like other businesses, utilities generally do not make additional investments or increase their expenses unless they can generate additional revenues and profits, either by serving additional customers, or by cutting costs or increasing margins. There is no reason to assume this is not the case here. The projected expenditures Idaho Power has identified must be presumed to generate additional revenues or other benefits that would offset their costs, in whole or in part. But Idaho Power has made no attempt to identify these offsetting benefits. Instead, it has focused on only one side of the ledger. Stated another way, this is another mismatch problem, where the Company is attempting to recover for projected cost increases while ignoring the increased revenues that would occur in the corresponding time frame. This violates one of the most important tenets of ratemaking, and should be rejected.

Q. YOU EARLIER STATED THAT KNOWN AND MEASURABLE ADJUSTMENTS SHOULD BE APPROACHED WITH CAUTION BECAUSE OF THEIR HIGH POTENTIAL FOR ABUSE. WHAT DID YOU MEAN BY THAT STATEMENT?

A. One of the obvious problems with known and measurable changes to test year results is that the utility has every incentive to identify changes that will increase its revenue requirement, but no incentive to ferret out changes that would decrease that revenue requirement. I am not suggesting that Idaho Power would deliberately conceal changes that would reduce its revenue requirement, just that it has no reason to look for them.

Q. CAN YOU PROVIDE AN EXAMPLE?

A. Yes. Idaho Power's Exhibit No. 14 calculates the Company's embedded cost of long-term debt. As that exhibit shows, one of Idaho Power's nine first mortgage bonds, a $50,000,000 issue with an effective cost of 8.54%, is scheduled to come due in March of 2004. At today's cost of capital, Idaho Power can roll this issue over at a savings of at least 269 basis points. This is a known and measurable change that will obviously decrease Idaho Power's cost of capital and revenue requirement, but the Company failed to include it in its known and measurable adjustments.

I will quantify the amount of this adjustment in my discussion of cost of capital issues, but my point here is that Idaho Power obviously did not look very hard for known and measurable changes that would benefit ratepayers rather than shareholders, or it would have included this item in its list of changes. This naturally makes one wonder what other favorable changes could be identified if Idaho Power had an incentive to seek them out. In any event, the one sided nature of the Company's incentives is why I pointed out there is a high potential for abuse in the use of known and measurable changes.

Q. PLEASE SUMMARIZE YOUR TESTIMONY ON REVENUE REQUIREMENT ISSUES.

A. Idaho Power's proposed test year contains a gross mismatch of revenues and expenses. I recommend remedying this defect by annualizing revenues to year-end 2003. This will reduce Idaho Power's requested increase by $9,731,765.

I further recommend that the Commission reject all of Idaho Power's post-test year adjustments except the known and measurable increase in depreciation rates. This reduces the Company's claimed Idaho jurisdictional revenue requirement by $11,786,222.

Cost of Capital Issues

Q. HAVE YOU REVIEWED DR. WILLIAM AVERA'S TESTIMONY REGARDING THE COST OF EQUITY FOR IDAHO POWER?

A. Yes, I have.

Q. WHAT IS YOUR INITIAL IMPRESSION OF THAT TESTIMONY?

A. Dr. Avera, like most cost of capital witness, discusses several alternative methods of determining Idaho Power's cost of equity. In general, most of these approaches follow modern cost of capital theories and methodologies. But his presentation suffers from stale capital market data and, with the updates I identify below, his proposed return on equity estimate must fall dramatically. I also disagree with his general characterization of the state of the electric utility industry.

Q. WHY DO YOU DISAGREE WITH DR. AVERA'S CHARACTERIZATION OF THE INDUSTRY?

A. Dr. Avera's testimony is replete with references to the electric utility industry's travails—from the California and Pacific Northwest market crises, to the Enron meltdown, and more recent problems such as the blackout in the East and ongoing battles over the regulation of regional transmission grids. All of these observations are accurate enough, but taken as a whole, this unrelenting litany of bad news paints too bleak a picture of the industry. The fact is that the overwhelming majority of the nation's electric utilities have weathered the recent disasters, and are in the process of getting "back to basics" and strengthening their core business. They are doing so in an economic environment that is nearly ideal for utilities. Interest rates are hovering just above their post World War II lows, and inflation is virtually nonexistent. Yes, there are still problems and uncertainties in the industry, but this is not unique to electric utilities. As the old Wall Street adage says, all stocks "must climb a wall of worry."

Q. HAVE THE SHAREHOLDERS OF IDAHO POWER FARED RELATIVELY WELL IN THIS PAST YEAR?

A. Yes. The calming of energy markets, and the upward trend in the stock market, has resulted in a rate of return to Idaho Power shareholders during the past year of more than 40%, which includes both price appreciation and dividend yield. While the previous few years produced some negative returns, the past year has generally provided a good investment environment. This suggests the Dr. Avera's doom and gloom outlook for the industry, and Idaho Power in particular, is not widely shared by investors.

Q. TURNING FROM GENERAL OBSERVATIONS TO A MORE SPECIFIC ANALYSIS, WOULD YOU PLEASE DESCRIBE THE METHODS DR. AVERA EMPLOYS IN HIS ATTEMPT TO DETERMINE IDAHO POWER'S COST OF EQUITY?

A. Dr. Avera uses two basic approaches in his cost of equity analysis: a discounted cash flow analysis and a risk premium analysis. For each approach, he offers a number of variations using alternative analytical methods. The average of all these approaches is an indicated cost of equity of 11.0%. This indicated result is no longer valid.

Q. WHY NOT?

A. Changing capital markets have changed the inputs to all of Dr. Avera's analytical methods. This naturally produces different results than Dr. Avera obtained when he performed his analysis. The following table shows the current results and the variation from Dr. Avera's original estimates.

Methodology	**Dr. Avera**	**Updated**	**Difference**	**Exhibit**
DCF	10.4%	10.0%	-0.4%	701
Risk Premium	11.2%	10.6%	-0.6%	702
Risk Premium	10.8%	9.7%	-1.1%	703
CAPM	11.7%	10.0%	-1.8%	704
Average	11.0%	10.1%	-1.0%	

The supporting calculations for this table appear in my Exhibits Nos. 701 through 704. 701 and 703 follow Dr. Avera's methods exactly with no changes other than updated numbers. 702 contains a correction described below to make the analysis consistent with Exhibit 703. 704 is revised to reflect the market recovery during the last half of 2003.

Q. PLEASE BRIEFLY EXPLAIN YOUR UPDATES AND REVISIONS TO DR. AVERA'S RATE OF RETURN METHODS.

A. My updates are each simple and straightforward. Dr. Avera developed his analyses using capital market information from last summer, and both debt and equity markets have improved enormously since that time. My Exhibit 701 takes Dr. Avera's discounted cash flow ("DCF") method and simply plugs in an updated figure for dividend yield calculation. As shown, changing from the August 2003 figure used by Dr. Avera to that of February 13, 2004, reduces his dividend yield from 4.4% to 4.0%. If I use his excessively high estimated growth rate of 6%, which I nevertheless accept for the purpose of Exhibit 701, his DCF recommendation drops to 10%.

My Exhibit 702 makes one simple correction to Dr. Avera's "authorized return" risk premium analysis. Note that on his Exhibit 8 in column (b) he uses the Average Public Utility Bond Yield in his calculations. But, on his following exhibit, Exhibit 9, Dr. Avera uses the yield on single A- rated bond. Most Idaho Power debt instruments carry the A- rated credit standing. The whole point of these exercises is to solve for Idaho Power's risk premium, not that of the average public utility. Dr. Avera's substitution biases his estimates upward, and I have corrected this inconsistency by using A- rated bond yields throughout. Exhibit 702 shows that updating Dr. Avera's risk premium analysis for a February 5, 2004, A- rated utility bond yield reduces his estimate of Idaho Power's equity return from 11.2% to 10.59% (the sum of 5.7% and 4.89% on Exhibit 702).

My Exhibit 703 replicates Dr. Avera's "realized return" method exactly, and only updates interest rates for A- rated bonds from Dr. Avera's August 2003 figure of 6.79%

(Avera, page 62, line 8) to the current A-rated yields of 5.7%. This single update reduces his risk premium method from 10.8% down to 9.71%, as shown on my Exhibit 703.

My Exhibit 704 updates Dr. Avera's capital asset pricing model ("CAPM") analysis for the recent changes in interest rates ("risk-free rate") and the market risk premium. The interest rate shown on Avera Exhibit No. 10 of 5.39% is, as of February 13, 2004, 4.98%. Dr. Avera's market risk premium, the derivation for which I disagree, has fallen from 8.85% to 5.64%. The correct market risk premium to use at this time is, however, 7.0%, as shown in my Exhibit 704. The sum of these updates reduces Dr. Avera's CAPM estimate of equity return from 11.7% to 10.0%.

Q. ARE THESE THE ONLY CORRECTIONS YOU HAVE TO DR. AVERA'S ANALYSIS?

A. No. One of his discounted cash flow ("DCF") approaches produces unreasonable results and should not be used by the Commission in any fashion.

Q. PLEASE EXPLAIN WHY THIS DCF METHODOLOGY SHOULD BE DISCARDED?

A. As Dr. Avera points out, the basic formula for computing cost of equity using the discounted cash flow analysis is relatively simple:

Cost of Equity = Dividend Yield + Growth Rate

The initial question is what data is to be used to determine the values for the dividend yield and growth rate portions of the equation?

Dr. Avera's DCF methodology relies very heavily on a reference group of other utilities selected from Value Line's western electric utilities group to develop Idaho Power's cost of equity. Dr. Avera uses the average 4.4% dividend yield for this group to supply the dividend yield portion of the equation. (As I explained above, this yield has now fallen to 4.0%.) He then uses three separate methods to estimate the growth rate. The average of analysts' earnings growth projections for the electric utility industry produces a growth rate of 4.6%.[1] His "sustainable growth rate" analysis indicates a growth rate of 4.7%. Finally, he finds that the 10-year historical average earnings growth rate for his proxy group is 7.3%. Taking these three approaches into account, he concludes "investors currently expect growth on the order of 5.0 to 7.0 percent for the average firm in the electric utility proxy group." Avera Direct, p. 55. Combining the 4.4% dividend yield with the mid point (6.0%) of his growth estimates produces his DCF cost of equity estimate of 10.4%.

Q. IS THIS A REASONABLE METHOD OF ESTIMATING IDAHO POWER'S COST OF EQUITY?

A. The methodology is not unreasonable, but its implementation is severely flawed. The most significant problem stems from Dr. Avera's selection of the utilities he uses in his analysis. Value Line's western electric utility group is actually comprised of 15 companies. From these companies, Dr. Avera understandably eliminates those that do not pay a dividend. But he then goes on to discard firms rated below investment grade by Standard & Poors, as well as Idaho Power itself. The result is that his dividend yield group consists of only 8 companies, and only 6 data points are used in his calculation of historical growth rates.

Q. WHY IS THIS AN IMPLEMENTATION FLAW?

A. The first problem with this selection process is that it high grades the proxy group. The second problem with this approach is that the group is so small that there is a serious risk

---

[1] Dr. Avera refers to the analysts' projections in his testimony but inexplicably does not include them in his final calculations.

of sampling errors. This is particularly true of Dr. Avera's historical growth rate analysis, where he uses only 6 data points for his calculations.

Q HOW SHOULD THESE PROBLEMS BE CORRECTED?

A. The dividend yield portion of the DCF equation can be improved by adding back the 4 dividend paying companies that Dr. Avera arbitrarily removed. These 12 companies have an average dividend yield of 3.79%, which is remarkably close to IDACORP's actual dividend yield of 3.9%.

Q. CAN DR. AVERA'S HISTORICAL GROWTH RATE ANALYSIS BE CURED IN A SIMILAR FASHION?

A. Unfortunately, no. The boom and bust in energy trading and the disaster in the California market produced wildly erratic year to year results in recent years for most of the electric utilities in the western United States. Consequently, most of those in the Value Line western utilities group have negative 5 and 10-year growth rates. The five companies with positive growth rates for both periods are not enough to comprise a valid sample, and even if they were, they are clearly not representative of the western electric utility industry as a whole.

Q. WHY DO YOU SAY THEY ARE NOT REPRESENTATIVE OF THE WESTERN ELECTRIC UTILITY INDUSTRY?

A. For both the 5 and 10-year historical calculations, there are only 6 data entries, and only 5 companies show positive growth rates for both periods. This is too small a sample to be statistically reliable.

Moreover, the sample is not really a sample of electric utilities. One half of the companies in the sample derive the majority of their revenue from activities other than electricity sales. MDU is a diversified conglomerate involved in oil, gas, and coal production, gas transportation and delivery, and heavy construction. It gets only 12% of its annual revenues from its electric utility division. Black Hills is also heavily involved in energy production and other activities, with only 38% of its revenues derived from electricity sales. Like MDU, Black Hills' historic growth rate is heavily influenced by fossil fuel prices. Finally, Sempra is the nation's largest natural gas distributor, with roughly 5 times as many natural gas customers as electric customers.

The third flaw in Dr. Avera's historical average approach is that it is distorted by unusual earnings fluctuations. To illustrate this point I have attached the Value Line analysis for PNM Resources as Exhibit 705. Even a cursory review of this data reveals that PNM's growth rate is nothing like the listed 5 and 10-year averages of 9.5% and 19%, respectively. In fact, PNM began the 18-year period covered by Value Line's data array by earning $2.00 per share, the same figure that it is projected to earn in 2004!

Q. WHAT DO YOU CONCLUDE FROM THIS ANALYSIS?

A. My conclusion is that Dr. Avera's historical average approach should be discarded in its entirety as inherently unreasonable. This leaves two alternative DCF methods for consideration. Using the corrected 3.8% yield figure that I discussed earlier, Dr. Avera's two remaining DCF cost of equity estimates are:

1) Analysts' growth rate - 3.8% yield + 4.6% growth = 8.4%
2) Sustainable growth - 3.8% yield + 4.7% growth = 8.5%

Q. DO YOU HAVE AN ESTIMATE OF IDAHO POWER'S COST OF EQUITY BASED ON YOUR CORRECTIONS TO DR. AVERA'S CALCULATIONS?

A. Yes. In effect, I am offering five different approaches that produce cost of equity results that range from 8.4% to 10.6%. The midpoint of this range is 9.5%. I personally would not use the low end of this range because I expect interest rates to increase somewhat in the not too distant future. On the other hand, an historical perspective and common sense suggest that the high end of the range is unreasonable even if interest rates move considerably.

Q. WHAT DO YOU MEAN WHEN YOU REFER TO AN HISTORICAL PERSPECTIVE?

A. Proceedings on Idaho Power's last rate case were conducted in 1994. In the Commission's January, 1995 order it found that Idaho Power's cost of equity was 11%. According to Value Line, the average yield on AAA corporate bonds during 1994 was 8%, and the earnings yield (the reciprocal of the 14.2 price to earnings ratio) for the Dow Jones Industrials was 7%. Barron's February 14th edition lists the current yield on an index of high grade corporate bonds as 5.73% and the Dow Jones Industrial's earnings yield as a bit below 5%.

Obviously investors' expected earnings on both bonds and stocks have dropped dramatically since 1994, by 200 basis points or more based on the bond and earnings yields cited above. In this environment, Idaho Power's request for an 11.2% return on equity, some 20 basis points higher than the Commission authorized in 1995, is unreasonable on its face.

Q. YOU STATED EARLIER THAT YOU WOULD ALSO HAVE A CORRECTION TO IDAHO POWER'S COST OF DEBT CALCULATION. HAVE YOU RECALCULATED IDAHO POWER'S EMBEDDED DEBT COSTS TO REFLECT THE REFINANCING OF THE $50 MILLION FIRST MORTGAGE BONDS?

A. Yes. The current A-rated utility bond rate is 5.7% as opposed to the 8.54% issuance coming due. Using the 5.7% and the average level of issuance expense associated with the refinancing, the current embedded cost of debt for Idaho Power is 5.839%.

Cost of Service Issues

Q. HAVE YOU REVIEWED THE COST OF SERVICE STUDY OFFERED BY IDAHO POWER IN THIS CASE?

A. Yes.

Q. WHAT DO YOU CONCLUDE FROM YOUR REVIEW?

A. In general, I conclude that Idaho Power's cost of service study is consistent with sound costing methods and prior Commission orders, with one very significant exception. The exception is that Idaho Power witness Ms. Brilz has modified demand allocators in a manner that not only departs from prior Commission orders, but departs from sound economic principles as well.

Q. WHERE HAS MS. BRILZ'S COST STUDY DEPARTED FROM SOUND ECONOMIC PRINCIPLES?

A. Economic principles require that the allocation of costs reflect cost causality, or the degree to which each class caused or contributed to the costs being allocated. In a cost of service study, this requires identifying the main usage factor causing a specific cost, and then allocating that cost to specific rate classes based on each class's contribution to that main usage factor. For example, generation and transmission demand costs are caused primarily by peak demands at specific times during the year. But Idaho Power's cost of service study is based, in one important particular, on allocators that do not reflect customer usage factors that cause the costs being allocated.

Q. CAN YOU IDENTIFY THE SPECIFIC ALLOCATORS USED BY IDAHO POWER THAT ARE NOT BASED ON SOUND ECONOMIC PRINCIPLES?

A. Yes. Idaho Power Company uses generation and transmission demand allocators that are simple averages of a weighted 12 CP allocator and an unweighted, or equal, 12 CP allocator. As a result, the allocations of generation and transmission demand costs are based in part on customer demands that do not cause or contribute to the costs being allocated. The result is that the Company's demand allocators attribute excess costs to off-peak and shoulder load periods of the year. This is not sound economics and cannot lead to sound ratemaking.

Q. HAS IDAHO POWER COMPANY EVER USED AN AVERAGED ALLOCATOR BEFORE?

A. Not for at least two decades. Idaho Power Company proposed the use of a weighted 12 CP allocator in the U-1006-185 case in 1983. In every cost of service study presented by Idaho Power Company in a rate case since then until this case, the Company has endorsed and utilized the weighted 12 CP method for generation and transmission demand.

Q. DOESN'T MS. BRILZ STATE THAT IDAHO POWER'S COST OF SERVICE STUDY IS THE "...SAME METHODOLOGY AS PREVIOUSLY FILED BY THE COMPANY IN CASE NO. U-1006-185, CASE NO. U-1006-265A, AND CASE NO. IPC-E-94-5 AND USED BY THE COMMISSION IN THE ALLOCATION OF REVENUE REQUIREMENT AMONG CUSTOMER CLASSES IN THOSE CASES."

A. Yes she does. However, I participated in each of those cases, and Idaho Power used only the weighted 12 CP to allocate generation demand and transmission costs. It never used a simple average of the weighted 12 CP and an unweighted 12 CP allocator. Ms Brilz's statement is both misleading and wrong.

Q. MS. BRILZ ALSO INDICATES THAT THE WEIGHTED 12 CP METHOD WAS USED BY THE COMMISSION TO ALLOCATE COSTS. DID THE COMMISSION EVER USE AN AVERAGE OF THE WEIGHTED 12 CP AND ANY OTHER ALLOCATOR?

A. No. In those cases cited by Ms. Brilz, the Commission reviewed several alternative cost of service studies, including the weighted 12 CP method. In each of those cases, the Commission endorsed the weighted 12 CP as the most appropriate cost of service study to use in allocating costs and setting rates.

Idaho Power first submitted the weighted 12CP methodology In Case No. U-1006-185. In reviewing that study, the Commission found:

> We find: For the limited purposes for which we use cost-of-service data in allocation of the revenue requirement among the customer classes, Idaho Power's weighted 12 coincident peak study may be reasonably used to represent costs. Although there could be improvements in both W12CP studies presented in this case, the similarities in the results obtained from both of them, which were the best cost-of-service studies presented in this case, show that we may use the Company's W12CP for the next step of the rate allocation process.

Order No. 17856, p. 13.

In Case No. U-1006-265A, the Commission again reviewed the weighted 12 CP method presented by the Company, as well as several other alternative studies presented by the Company and other parties. It found:

> B. The Choice of the Cost-Of-Service Study to be Used. Idaho Power prepared five cost-of-service studies: A Weighted 12 Coincident Peak (IPCo W12CP) study, a 12 Coincident Peak (IPCo 12CP) Study, an Average and Excess Demand (IPCo AED) study, a Positive Excess Demand (IPCo PED) study, and a Modified Positive Excess Demand

> (IPCo MPED) study. In addition, the City of Boise presented two variations of the Company's W12CP called Boise I and Boise II. FMC presented a modified weighted 12 coincident peak (FMC MW12CP) study and a 7 coincident peak (FMC 7CP) study. The Staff presented an alternative weighted 12CP (Staff W12CP) study and an unweighted 12CP (Staff U12CP). The results of those studies are shown on Table 6 on the following page. For the reasons stated in the following pages of this Order, we will use the Company's W12CP as a starting point in our allocation of revenues among the customer classes.

Order No. 21365. It is worth noting that, in this order, the Commission specifically rejected the unweighted 12 CP proposed by Staff.

Finally, in the most recent Idaho Power rate case, the Commission again endorsed use of the weighted 12 CP methodology, not an alternative methodology or some averaging of different methodologies.

> In this case, the Commission was presented with only one cost-of-service study, a study based on the W12CP method prepared by the Company, and the IPCo study as modified by Staff. The testimony in this case almost universally supports the use of a W12CP methodology, and thus we find it appropriate and reasonable to once again utilize the W12CP methodology to establish revenue requirement for the customer classes.

Order No. 21365, p. 13.

Q. CAN YOU THINK OF ANY REASON THAT IDAHO POWER COMPANY WOULD CHANGE TO A NEW ALLOCATION METHODOLOGY AFTER USING THE WEIGHTED 12 CP METHOD FOR SO LONG?

A. I can think of no sound reason based on economic principles. The only other reason I can think of is based on the actual result that occurs with the new allocation methods. All classes with the exception of the irrigation class, Schedule 24, receive higher allocations of generation and transmission demand costs with Idaho Power's new averaged allocator as compared with the weighted 12 CP allocator. The irrigation class receives a smaller allocation of generation and transmission demand costs. This is shown on Ms. Brilz

Exhibit No. 40. Thus, Idaho Power's averaged allocator reduces the measured size of the subsidy to the irrigation class, when in fact the subsidy has grown. The irrigation subsidy is still extremely large, but would be even larger if the correctly weighted 12 CP method were used. I can only assume that Idaho Power Company made the decision to change allocation methods in this case to understate the severity of the problem with irrigation rates.

Q. HAVE YOU DETERMINED HOW THE COST OF SERVICE STUDY WOULD CHANGE IF THE WEIGHTED 12 CP METHODOLOGY WERE USED RATHER THAN IDAHO POWER'S NEW AVERAGED 12 CP?

A. Yes, I have. I used Idaho Power Company's cost of service model to reallocate costs using the weighted 12 CP allocators for generation and transmission costs, rather than Idaho Power's new averaged 12 CP allocators. The results of that study are shown in my Exhibit 706. As is obvious in Exhibit 706 and as I discussed above, the cost of service for all classes other than the irrigation class are lower in my study compared to the Company's, and the cost of service for the irrigation class is higher. I urge the Commission to stick with its prior informed conclusions and continue to endorse the sound and proven weighted 12 CP allocators.

The Irrigator Subsidy Issue

Q. WHAT DO YOU MEAN BY THE TERM "SUBSIDY" IN THESE PROCEEDINGS?

A. I use the term subsidy to refer to any intentional, consistent and significant underpricing of electricity to a class of Idaho Power customers, compared with the actual cost of serving the particular customer class. The reason I term this shortfall between the rates paid and the cost of service a subsidy is because, under normal ratemaking, any shortfall to a class is made up by overcharging some or all of the remaining customer classes.

Q. IS THE SUBSIDY ISSUE RELEVANT TO THESE PARTICULAR PROCEEDINGS?

A. Yes, very much so. Under Idaho Power's present rate structure, the irrigation class is being subsidized by $40.5 million annually. This subsidy is not good for Idaho and must be addressed in these proceedings. Allowing it to continue is detrimental to residential, commercial and industrial customers, and, in the long run, even to the irrigators themselves.

Q. ARE ALL CLASSES OF CUSTOMERS OTHER THAN IRRIGATORS BEING OVERCHARGED AT PRESENT?

A. Yes. The following table provides an approximate breakdown of Idaho Power's calculated subsidy of $26 million annually that results from its proposed rate design in this case. It is important to note that this is the subsidy from other classes <u>even after the irrigation class is assigned a disproportionate increase in this case</u>.

CUSTOMER CLASS	AMOUNT OF SUBSIDY PAID
Residential	$12,100,000
Small General	900,000
Large General	5,900,000
Lighting	1,500,000
Large Power	3,000,000
Unmetered	260,000
St. Lighting	400,000
Traffic	160,000
Micron	800,000
Simplot	280,000
DOE	300,000
	$25.6 million

Source: Idaho Power Company Exhibit No. 61.

As the table indicates, all remaining customer classes under Idaho Power's proposal are required to pay portions of the subsidy to the irrigation class.

Q. DOES IDAHO POWER OFFER A MEANS TO EVENTUALLY END THIS SUBSIDY?

A. No, and without annual rate cases, the continuing annual $25.6 million subsidy could go on indefinitely.

Q. DO YOU HAVE A PROPOSAL TO ELIMINATE THE SUBSIDY TO THE IRRIGATION CLASS?

A. Yes. One obvious but abrupt means of eliminating the subsidy would be to raise irrigation rates in this rate case by the 67.1% required to bring the irrigators' rates in line with the cost of serving that class. Under this action, all ratepayer classes could be immediately aligned with their respective costs of service, and Idaho Power is made whole with respect to its revenue requirement. However, the same outcome for all nonirrigation rate classes, and for Idaho Power can be accomplished <u>in this case</u> without the abrupt 67.1% increase to the irrigation class.

Q. PLEASE EXPLAIN YOUR PROPOSAL TO MOVE ALL NONIRRIGATION RATE CLASSES TO COST OF SERVICE AND ELIMINATE THE SUBSIDY ONCE AND FOR ALL?

A. I propose that the Commission in this case adopt a three step remedial program with respect to rate design:

1. Set all nonirrigation rate classes' rates equal to respective costs of service;

2. Raise the irrigation service class's rate by 18.6% (not 25% as proposed by Idaho Power);

3. Have Idaho Power establish a deferred accounting mechanism to both debit all annual amounts of unrecovered irrigation subsidy for 5 years and credit for set incremental increases to the rates of the irrigation class over the next 5 years, with carrying charges on unrecovered balances.

Q. HOW WOULD THIS ACCOUNTING MECHANISM WORK?

A. Idaho Power establishes a deferred regulatory asset or similar account. When the new rates resulting from these proceedings go into effect, there would be a revenue shortfall monthly, which is accumulated and deferred into the Subsidy Account. The revenue shortfall is the result of (1) setting all nonirrigation rate classes' rates in these proceedings equal to their respective costs of service and, (2) raising irrigation service rates only part way (recall irrigator rates are far below cost of service) toward cost of service in this case. The difference between the irrigation service rates set in this case and the cost of serving this class becomes a "stranded subsidy" that, unlike the present, is not charged to other rate classes. Instead, this stranded subsidy is placed into the Subsidy Account.

In order for this Subsidy Account to be cleared over a fixed period of years, the irrigation service rate is raised gradually but automatically in each of a predetermined number of years. The balances in the Subsidy Account increase in early years due to the revenue shortfall, but decrease to zero in later years with the automatic increases to rates.

Q. CAN YOU PROVIDE A NUMERICAL ILLUSTRATION OF HOW THIS MECHANISM WOULD WORK?

A. Yes. My Exhibit 707 uses the correct data in this case relevant to the Subsidy Account. The exhibit uses a 5-year period in which the subsidy problem is eliminated. As shown, the present subsidy now being paid by nonirrigation rate classes, before the 25% increase proposed by Idaho Power, is $40.5 million per year.

Instead of initially raising irrigation service rates by 25%, my example assumes a lower first year increase of 18.6%, but raises irrigator rates by an additional 18.6% in each of the next 4 years as well. Just as the initial years' increase leaves irrigation service rates below cost of service and increases the Subsidy Account balances, rates in years 4 and 5 are above cost of service to begin paying down these balances.

In terminal year 6, when the Subsidy Account balances are zero, the irrigation service rate is reduced by 28.77%, back down to exactly the irrigation service class cost of service. The result of the whole process is to transfer the $40.5 million subsidy that is now on the backs of all other nonirrigation customers into an interest bearing account administered by Idaho Power. At the end of year 5 the multi-decade rate subsidy problem will have been eliminated and all customers' rates, including those of the irrigators, will have been set equitably at respective costs of service.

Q. ARE THERE OTHER REASONABLE WAYS IN WHICH TO IMPLEMENT THE SUBSIDY ACCOUNT MECHANISM?

A. Yes, although I believe that the method expressed in Exhibit 707 is reasonable. Exhibit 708 provides an alternative. There I illustrate the equivalent accounting, but assume a first year increase of 25% to irrigators, but allow the rate increases and the balances to be cleared over a period of 10 years.

This accounting mechanism could be implemented in any number of ways, but the important consideration is that nonirrigation rate classes are immediately and permanently relieved of the burden of the subsidy.

Finally, I should point out that reductions in Idaho Power's requested rate increase would decrease the annual increases to the irrigation class.

Q. UNDER YOUR PROPOSED DEFERRED MECHANISM, WOULD IT BE IMPORTANT TO PROVIDE MAXIMUM ASSURANCE TO IDAHO POWER AND

THE INVESTMENT COMMUNITY THAT THE COMPANY BEARS NO RISK OF UNDER COLLECTING THESE BALANCES?

A. Absolutely. The purpose of this proposal is not to shift the burden from ratepayers to shareholders; the purpose is to eliminate the burden altogether. To this end the Commission should make clear in any order that adopts this mechanism that any underrecovery of Subsidy Account balances would not be borne by the Company. And, as this mechanism results in the use of Idaho Power credit, a return needs to accompany these balances.

Q. WOULD LOAD GROWTH OR LOAD REDUCTION IN THE IRRIGATION SERVICE CLASS BE TAKEN INTO ACCOUNT IN THE DEFERRAL ACCOUNTING MECHANISM?

A. Yes. My exhibits use a fixed level of kilowatt hour usage of 1.62 billion kwh in the irrigation service class. My review of Idaho Power's forecast indicates that this is a reasonable assumption. Load growth would tend to clear the balances earlier. Load reduction would potentially leave positive balances that would be the responsibility of irrigation customers or all ratepayers, but not Idaho Power.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS WITH REGARD TO THE IRRIGATION SUBSIDY.

A. The merits and benefits of setting rates based upon cost of service have long been recognized in Idaho. A subsidy of the magnitude that is currently flowing to the irrigation is simply intolerable. I have proposed what I believe to be the least painful alternative for solving this problem, and I urge its adoption by the Commission.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on this 19th day of February 2004, I caused to be served a true and correct copy of the foregoing by the method indicated below, and addressed to the following:

Jean Jewell Idaho Public Utilities Commission 472 W. Washington Street P.O. Box 83720 Boise, ID 83720-0074	______ U.S. Mail __X__ Hand Delivered ______ Overnight Mail ______ Facsimile ______ E-Mail
Barton L. Kline Monica B. Moen Idaho Power Company P.O. Box 70 Boise, ID 83707	______ U.S. Mail __X__ Hand Delivered ______ Overnight Mail ______ Facsimile ______ E-Mail
John R. Gale Vice President Regulatory Affairs Idaho Power Company P.O. Box 70 Boise, ID 83707	______ U.S. Mail __X__ Hand Delivered ______ Overnight Mail ______ Facsimile ______ E-Mail
Lisa Nordstrom Weldon Stutzman Deputy Attorney Generals Idaho Public Utilities Commission 472 W. Washington Street P.O. Box 83720 Boise, ID 83720-0074	______ U.S. Mail __X__ Hand Delivered ______ Overnight Mail ______ Facsimile ______ E-Mail
Peter J. Richardson Richardson & O'Leary 99 E. State Street, Ste. 200 P.O. Box 1849 Eagle, ID 83616	______ U.S. Mail __X__ Hand Delivered ______ Overnight Mail ______ Facsimile ______ E-Mail
Don Reading Ben Johnson Associates 6070 Hill Road Boise, ID 83703	______ U.S. Mail __X__ Hand Delivered ______ Overnight Mail ______ Facsimile ______ E-Mail

Randall C. Budge Eric L. Olsen Racine, Olson, Nye, Budge, Bailey 201 E. Center P.O. Box 1391 Pocatello, ID 83204-1391	______ U.S. Mail ______ Hand Delivered __X__ Overnight Mail ______ Facsimile ______ E-Mail
Anthony Yankel 29814 Lake Road Bay Village, OH 44140	______ U.S. Mail ______ Hand Delivered __X__ Overnight Mail ______ Facsimile ______ E-Mail
Lawrence A. Gollomp Assistant General Counsel U.S. Department of Energy 1000 Independence Ave. SW Washington, DC 20585	______ U.S. Mail ______ Hand Delivered __X__ Overnight Mail ______ Facsimile ______ E-Mail
Dennis Goins Potomac Management Group 5801 Westchester Street Alexandria, VA 22310-1149	______ U.S. Mail ______ Hand Delivered __X__ Overnight Mail ______ Facsimile ______ E-Mail
Dean J. Miller McDevitt & Miller 420 W. Bannock Street P.O. Box 2564 Boise, ID 83701	______ U.S. Mail __X__ Hand Delivered ______ Overnight Mail ______ Facsimile ______ E-Mail
Jeremiah J. Healy United Water Idaho Inc. 8248 W. Victory Road P.O. Box 190420 Boise, ID 83719-0420	______ U.S. Mail __X__ Hand Delivered ______ Overnight Mail ______ Facsimile ______ E-Mail
William M. Eddie Advocates for the West 1320 W. Franklin Street P.O. Box 1612 Boise, ID 83701	______ U.S. Mail __X__ Hand Delivered ______ Overnight Mail ______ Facsimile ______ E-Mail

Nancy Hirsh NW Energy Coalition 219 First Ave. South, Ste. 100 Seattle, WA 98104	______ U.S. Mail ______ Hand Delivered __X__ Overnight Mail ______ Facsimile ______ E-Mail
Dennis E. Peseau, Ph.D. Utility Resources, Inc. 1500 Liberty Street SE, Ste. 250 Salem, OR 97302	______ U.S. Mail ______ Hand Delivered __X__ Overnight Mail ______ Facsimile ______ E-Mail
Brad M. Purdy Attorney at Law 2019 N. 17th Street Boise, ID 83702	______ U.S. Mail __X__ Hand Delivered ______ Overnight Mail ______ Facsimile ______ E-Mail
Michael Karp 147 Appaloosa Lane Bellingham, WA 98229	______ U.S. Mail ______ Hand Delivered __X__ Overnight Mail ______ Facsimile ______ E-Mail
Michael L. Kurtz Kurt J. Boehm Boehm, Kurtz & Lowry 36 E. Seventh Street, Ste. 2110 Cincinnati, OH 45202	______ U.S. Mail ______ Hand Delivered __X__ Overnight Mail ______ Facsimile ______ E-Mail
Thomas M. Power Economics Department Liberal Arts Building 407 University of Montana 32 Campus Drive Missoula, MT 59812	______ U.S. Mail ______ Hand Delivered __X__ Overnight Mail ______ Facsimile ______ E-Mail

Heidi C. Meier

Heidi C. Meier