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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE TO ELECTRIC CUSTOMERS IN THE STATE OF IDAHO.	CASE NO. IPC-E-07-8

IDAHO POWER COMPANY

DIRECT REBUTTAL TESTIMONY

OF

LORI SMITH

Q. Please state your name.

A. My name is Lori Smith.

Q. Are you the same Lori Smith that presented direct testimony in this proceeding?

A. Yes.

Q. What issues will you be responding to in your rebuttal testimony?

A. My testimony explains why the Company's forecast test year in this case better reflects the operating conditions the Company expects to experience during the time rates will be in effect rather than Staff's proposed historic test year. I will also provide information on the Company's 2007 fourth quarter results that provides additional validation as to the accuracy of the Company's forecasted revenue requirement. In response to Staff witness Carlock's concern regarding the absence of any quantification of harm caused by regulatory lag, I will provide an overview of the economic impacts of regulatory lag on Idaho Power Company. Finally, I will respond to several adjustments proposed by other parties.

Q. Staff recommends use of an historic test year to determine Idaho Power's rates. Why is it important that the test period and the rate-effective period closely match each other?

A. To provide the Company a reasonable

opportunity to earn its allowed rate of return, the new rates would ideally take effect with the commencement of the test year. With this underlying premise in mind, the Company filed the forecast test year based on its intimate knowledge of the contributing factors that hinder the Company's ability to earn its allowed rate of return. These factors include the costs of load growth that currently outpace revenue that can be obtained with the rates set based on an historical test year or a hybrid test year. As a result of load growth, the Company has the need to acquire new generating resources, build transmission lines and stations for reliability purposes, and maintain our aging existing resources in an environment of rising costs.

Q. Do you believe the Company's forecast used to determine its proposed test year is reasonable?

A. Yes. The Company's forecast is: 1) grounded on a consistent forecast methodology utilized by the Company; 2) reflective of realistic and systematic cost and revenue projections; 3) supported by expenditure forecasts that are developed and supported at the operating levels of the Company; 4) and has been scrutinized by business unit management and the Idaho Power Company management.

Q. Please explain how Idaho Power Company's test year forecast is grounded in consistent forecast methodology?

A. The 2007 test period began by using historical information for the year ending December 31, 2006. From the base year, each of the revenue requirement components was normalized or adjusted to reflect expectations for 2007 financial and operating activities. This forecast process used the same process that has been in place for several years to produce financial forecasts that are used by Idaho Power's management.

Q. Does the forecasted data the Company used to support its application for rate relief reflect realistic and systematic cost and revenue projections?

A. Yes. The normalized revenues and net power supply expense estimation process is the same that has been used in prior cases when a historical or hybrid test year has been filed. Additionally, the projections relied upon in this application are integrally tied to the operations and management of the Company. It is based on the same information that management sees in carrying out its responsibilities. Some select financial measurements in this application are also used for providing metrics to the financial community. The Company strives to be as accurate as possible in the data that it presents.

Q. Has the preparation of the Company's forecast test year in this case been closely scrutinized?

A. Yes. For the reasons I have just described, there has been great attention to detail in the preparation of this forecast. Every effort has been made to provide an appropriate explanation and support of the forecasted components included in this forecast test year. Throughout the preparation of the forecast, we have used a "bottom-up" approach to ensure that the business units that will build, operate and maintain the system during the rate effective period are in agreement with the projected levels of expenditure.

Q. Is it possible to produce a test year that is free from the uncertainty of prediction?

A. No. All rate proceedings inherently have a level of estimates, anticipated adjustments or modeling outputs that are based on assumptions and inputs from predictive models. The use of an historic test year does not remove this issue from a revenue requirement proceeding. Historical test years include estimates for annualizing and known and measurable adjustments to the rate effective period. These adjustments require the Commission to exercise informed judgment about how to best project future data or adjust historical data to reflect conditions in the rate effective period. The process, whether one uses an historic period or forecast period, is the same.

Q. Do you have any other general observations about the use of a forecast test year?

A. Yes. Idaho Power Company finds itself in a period of both rising capital and O&M costs. These costs are best captured in the forecast test year period. These escalating costs cannot be offset with efficiency gains, attrition, or cost cutting. Rates should be set for customers today that match the cost to serve those customers today. A business that doesn't recover its current costs will financially under-perform. This has been the experience of the Company for several years, even given two general rate increases since 2003.

The regulatory lag inherent in an historical or a partial forecast test year does not currently permit rates that are commensurate with a cost structure that is rising to meet electrical needs of a growing customer base. My testimony demonstrates that the Company has applied a rational, systematic and comprehensive approach in forecasting its test year requirement. I continue to believe for purposes of this proceeding, a forecast test year beginning January 1, 2007 and ending December 31, 2007, is the most appropriate. Even the use of a 2007 forecast test year establishes rates that will not take affect until 2008.

Q. Can you please provide an update of key capital expenditure and expense results through November 2007 that validates the forecasted values contained in the forecast test year used by the Company?

A. Yes. I have obtained actual data for several significant components of the forecast test year. This actual data is for the periods June year-to-date (YTD), September YTD, and November YTD. I then compared this actual data to the Forecast Test Year Total the Company filed. The components I have selected are key variables that Mr. Said uses to determine the Total System revenue requirement and ultimately the Idaho jurisdictional revenue requirement. The primary components I have included are Electric Plant in Service excluding Asset Retirement Obligations (ARO)(EPIS), Accumulated Provision for Depreciation and Amortization, Net Electric Plant in Service, Other Operating Revenues, Operation and Maintenance Expenses (O&M), Depreciation and Amortization, and IERCO operating net income.

	YTD June 2007	YTD Sept 2007	YTD Nov 2007	Forecast Test Year Total
EPIS	$3,647,262,730	$3,708,539,029	$3,788,785,684	$3,778,910,294
Accumulated Provision for Depreciation and Amortization	1,600,383,439	1,624,352,106	1,635,886,117	1,607,824,827
Net EPIS	2,046,879,291	2,084,186,923	2,152,899,567	2,171,085,467
Other Operating Revenues	25,504,551	39,293,118	48,827,366	60,368,018
O&M Expenses	151,514,351	224,846,522	271,001,079	290,673,032
Depreciation and	50,902,708	76,869,380	94,307,122	104,120,916

Amortization				
IERCO Net Income	1,815,205	2,917,192	4,661,020	5,248,215

Q. What conclusion do you draw from this table of actual components compared to the forecast test year total?

A. I believe this information supports the Company's forecast test year and adequately reflects the operating costs and capital expenditures that Idaho Power Company is currently experiencing to operate effectively. By the end of 2007, the Company will have made significantly more capital investments of prudently incurred property plant and equipment and will have spent significantly more operating expenses to provide reliable service to its customers. The forecast test year is a more reasonable representation from which to set rates for the coming year to effectively provide the Company the opportunity to earn its allowed rate of return established by the Commission.

Q. Other witnesses have used the term regulatory lag. Please define your understanding of the term "regulatory lag" as it applies to this proceeding.

A. Regulatory lag occurs when there is a mismatch between the time period used for test year calculations and when resulting rates go into effect. For purposes of this proceeding, I am using the term regulatory lag or attrition as a "decline in the rate of return earned *** [occurring] when rate base and/or cost of service increases faster than revenue and is caused both by inflation and by expansionistic construction programs which do not generate additional comparable revenue". *Utah Power & Light v. Idaho Public Utilities Commission, 102 Idaho 282 (1981).*

Q. In reviewing Staff's testimony in which it presents its revenue requirement recommendations, do you believe Staff's recommendations create regulatory lag?

A. Yes. The Company has incurred significant expenses and made substantial capital investments that it will have no opportunity to recover if the Commission accepts Staff's recommendations. Staff has filed a test year based on 12 months ending June 2007 for rates to be in effect late in the first quarter of 2008. Staff's filing also includes many timing mismatches between revenue, expenses and plant identified in Mr. Gale's, Mr. Steve Keen's, and Mr. Said's testimony. The annualizing and known and measurable adjustments Staff proposes only address a limited number of items where timing mismatches occur. When regulatory lag exists, it places financial pressure on the Company by reducing its cash flow and rate of return.

Q. Can you provide a hypothetical example and timeline of how regulatory lag associated with rate base items impacts Idaho Power Company?

A. Yes. Assume that a utility has constructed an asset for a total cost of $10 million including allowance for funds used during construction (AFUDC). The asset was constructed over three years and was placed in service in April of 2007. Further assume that the company also files for rate relieve using a 2007 forecasted test year with rates expected to be in effect by January 2008.

Because the asset is placed in service nine months prior to rate recovery, the company experiences regulatory lag. When the asset is placed in service in April 2007, regulatory accounting requires that the company no longer record AFUDC which capitalizes the cost of financing the asset's construction by recording income. Assuming a 10-year book life, the company records months of depreciation expense totaling $750,000 ($10 million divided by 120 months multiplied by 9 months) in 2007. In the company's 2007 forecast test year, the asset is included in rate base net of accumulated depreciation at $9,250,000 ($10 million original cost less $750,000 of depreciation expense). Because the asset is not reflected in rates until January 2008, the company will not recover the $750,000 in depreciation expense taken in 2007 and will not earn its authorized rate of return on that asset for those 9 months in 2007.

Let us say that one assumption in the hypothetical changes. The company waits until the end of

2007 and files for rate relief with 2007 actual test year data and does not expect a rate increase until October 2008. In this case, the company would still include $9,250,000 ($10 million original cost less $750,000 of depreciation expense) in rate base in its 2007 test year filing. The company continues to record depreciation expense and forgoes AFUDC through 2008. Because rates do not go into effect until October 2008, the company never recovers the depreciation expense of $1,500,000 (18 months - April 2007 through September 2008). During those 18 months, the company does not earn its authorized rate of return on that asset.

I would note that as Mr. LaMont Keen notes in his testimony, the Company is in a period of significant plant growth due to customer growth, generation and transmission requirements identified in the Company's 2006 Integrated Resource Plan, and the rising costs of preserving the Company's existing power plants and transmission and distribution infrastructure. This growth is expected to continue well into the future. From 2000 to 2006, Idaho Power's net plant has grown at an annualized rate of 4.7% with $520 million in new plant added over that period of time. Normalized system sales have grown at an annualized rate of 1.3% over the same period.

Q. Staff recommends using a 13 month average for the period ending June 2007 to determine Total Electric

Plant in Service. Can you demonstrate the impact this methodology has on regulatory lag?

A. Yes. Staff's use of a test period ending June 2007 with electric plant included on the basis of 13 month averages, results in adverse regulatory lag. By comparing Staff's proposal of Electric Plant in Service (EPIS) to actual results as of November 2007, the impact of regulatory lag on the Company's authorized return can be demonstrated. For purposes of this analysis, annualizing and known and measurable adjustments by Staff have been included for illustrative purposes only and should not be construed as my agreement with these adjustments. Staff's 13 month average EPIS using a June 2007 year end and including adjustments equals $2,065,138,126. Because December 2007 actual EPIS is not available, actual November 2007 results will be used for comparison purposes. Very conservatively, no adjustments have been made for annualizing or known and measurable adjustments. Actual Electric Plant in Service as of November 2007 equals $2,152,899,567. The difference of $87,761,441 is the amount of EPIS on which the Company has no opportunity to earn a just and reasonable return. The table below quantifies the amount of under recovery using both Staff proposed Weighted Average Cost of Capital (WACC) and Company-proposed WACC.

/ / /

	Staff WACC	IPC WACC
Difference	$87,761,441	$87,761,441
WACC	7.864%	8.561%
Tax Gross-up	1.642	1.642
Under Recovery	$11,332,610	$12,337,039

Because of the short time period available to prepare rebuttal testiomany, I have not had the opportunity to fully analyze and demonstrate the effects of regulatory lag associated with all aspects of EPIS. The above calculation demonstrates only the return component associated with the mismatch of EPIS with the time the rates will be in effect. With growing EPIS, other items would also experience under-recovery due to regulatory lag. These items include depreciation expense and the monthly adding of EPIS beginning in January 2008 which could also be quantified. However, because of time constraints they have not been quantified.

Q. Can you provide an example of how the adverse effects of regulatory lag associated with O&M impacts the financial integrity of Idaho Power?

A. Yes. Regulatory lag associated with O&M is most clearly demonstrated with an example comparing Other O&M included in Idaho Power's 2007 forecasted test year with the 2008 Other O&M forecast. "Other O&M" is a subset of Total Operating and Maintenance Expenses.

In the Company's 2007 forecasted test year, Other O&M was included at $288,932,502 before adjustments. To properly compare the amount to the 2008 estimate which excludes demand side management (DSM) and pension expense, DSM ($15,732,910 from Schwendiman - Exhibit 25) and pension ($4,607,443 from Schwendiman - Exhibit 25) must be removed. Annualizing and known and measurable adjustments from Smith - Exhibit 18 must be added. Finally, an assumption of 1.8% for normalized load growth from 2007 to 2008 is incorporated. The result is that Idaho Power would expect to receive $281,316,961 in 2008 if new rates were in effect beginning in January 2008. See accompanying Exhibit 69 for the full calculation.

The Company's board approved 2008 expenditures in the amount of $282,104,200 excluding DSM programs. Pension expense is no longer recorded. The Company's 2008 operational incentive payment is expected to be $6,535,000. The total of these amounts ($288,639,200) can then be compared to the revenue amount ($281,316,931) expected to be received. The shortfall amount of $7,322,239 is the result of adverse regulatory lag and will never be recovered by the Company.

Q. Can you perform the same analysis you described in your answer to the prior question to address Staff's proposed Other O&M?

A. Yes. I believe Staff begins with 12 months ending June 2007 Other O&M which equals $281,559,388. Staff then makes negative adjustments totaling $11,660,268 in reductions. My inclusion of these adjustments is only for illustrative purposes and should not be construed as my agreement to these adjustments. Staff adjusted Other O&M is then grown at 1.8% to reflect growth in normalized load from 2007 to 2008 to estimate growth in recovery. The result is that IPC would expect to receive $274,757,304 in 2008 if new rates were in effect beginning in January 2008. See accompanying Exhibit 70 for the full calculation.

Idaho Power's board approved its 2008 expenditures in November 2007. The total approved was $282,104,200 excluding DSM programs. Pension expense is no longer recorded and not included. The Company's 2008 operational incentive is expected to be $6,535,000. The total of these amounts ($288,639,200) can then be compared to the amount ($274,757,304) expected to be received under Staff proposal. The shortfall of $13,881,896 is the result of adverse regulatory lag and will never be recovered by the Company. Thus, Staff's position further exacerbates the already negative current impact of regulatory lag on Other O&M by approximately $6.6 million.

Q. Idaho Power included annualizing adjustments for payroll and known and measurable adjustments for a 2008 salary structure adjustment (SSA) (Smith - Exhibit 18). Don't these adjustments eliminate regulatory lag associated with Other O&M?

A. No. These adjustments only address specific payroll issues. Labor is only 42% of the 2008 O&M budget. The annualizing adjustment for payroll simply adjusts test year payroll expense to reflect December 2007 employment levels. It does not consider growth in the number of employees in 2008 and related increases to employee benefits. The SSA is a known and measurable adjustment recognizing that the Company would be increasing salaries to continue to attract and retain high quality employees in the labor markets in which it operates. On November 15, 2007 the IPC Board of Director's approved a 3.25% SSA effective December 15, 2007. The SSA adjustment used in the Company's filing was 3.00%.

The Company makes no adjustments to Other O&M to reflect additional costs expected in 2008 which include but are not limited to growth in employment levels to serve a growing customer base and to maintain additional infrastructure, increased compliance costs for Sarbanes-Oxley Act of 2002 and the FERC's Code of Conduct rules, inflation, and other cost increases to support growth and maintain reliability.

Q. Please describe regulatory lag impacts associated with the PCA's load growth adjustment rate (LGAR) and its impact on the financial health of Idaho Power Company.

A. LGAR, also referred to as Expense Adjustment Rate for Growth (EARG), is another significant source of adverse regulatory lag for Idaho Power. It disallows collection of net power supply costs that are necessary to serve increases in load for any reason, whether driven by customer or weather related growth. Under the current PCA methodology, as long as the Company has load growth between the test year used for determining base rates and the time those rates are in effect, the mismatch will result in an adverse impact from regulatory lag.

The resulting adverse impact from regulatory lag from this mechanism is a permanent loss to IPC and is the result of two mismatches. First, the mechanism compares normalized system load from the most recent test year with actual system load which includes both customer growth, weather volatility, and any other factors affecting demand. Historical PCA information back to 1997 was readily available and since 1997, actual system load has always been higher than normalized system load included in rates which resulted in the under recovery of prudently incurred net power supply costs. Second, the difference between normalized system load and actual system load is multiplied by a rate that is greater than what is being collected in general rates.

To illustrate the two components of LGAR's regulatory lag, please consider the analysis of 2007 year to date through November as presented on Exhibit 71 - Column 7. Through November 2007, actual system load has exceeded normalized system load established in the 2005 rate case by 946,884 MWhs. From January through March, differences were multiplied by $16.84 with the rate changing as a result of IPUC Order No. 30215 to $29.41 for April through November. After jurisdictionalization and sharing, the Company increased its PCA deferral expense by $22,072,707. The offset to this expense is what is collected through base rates. The embedded rate currently being collected for PURPA power purchase contracts and other variable power supply costs equals $6.81 per MWh. When multiplied by the change in load adjusted for losses, the Company has collected $5,582,405 on the increased load. When netted, the LGAR mechanism results in a pretax loss to IPC of $16,490,302 contributing to the Company's inability to earn its authorized rate of return.

Q. Has the PCA's LGAR mechanism ever resulted in a benefit to Idaho Power?

A. To the best of my knowledge, the LGAR has never resulted in a benefit to the Company for a total calendar year or a total PCA year (April through March). Exhibit D shows an extended analysis of LGAR beginning in 2001 through November 2007, the LGAR mechanism net of what is recovered through base rates has resulted in a cumulative pretax loss of $71.4 million which will be never recovered by Idaho Power and has contributed to the Company's inability to earn its authorized rate of return. This combined with the 10% sharing of non-PURPA net power supply costs above base non-PURPA net power supply costs places extraordinary financial pressure on Idaho Power during a time of continuing drought and growing system load.

Q. You mentioned that the 10% sharing of non-PURPA net power supply costs above base net non-PURPA power supply costs adversely impacts the Company's finances. What is financial impact of regulatory lag associated with non-PURPA qualifying net power supply costs for the 11 months ending November 2007?

A. IPC monitors regulatory lag associated with the PCA closely. In addition to LGAR described above, during years where actual net non-PURPA power supply costs are different than base net non-PURPA costs, the difference is shared with ratepayers. IPC absorbs 10% of the difference while ratepayers receive 90%. This lag could be positive or negative. For the 11 months ending November 2007, the actual non-PURPA net power supply costs equal

$206,331,061 as compared to $39,936,874 for base non-PURPA net power supply costs. The difference of $166,394,187 is jurisdictionalized and shared between Idaho ratepayers and the Company. After jurisdictionalization and the 10% sharing, IPC's bears $15,657,693 of these costs which contribute to the Company's inability to earn its authorized rate of return.

For the 11 months ending November 2007, the sum of the effects resulting from LGAR and for the non-PURPA net power supply costs is a loss of $32,147,995 on a pretax basis. After tax, the loss to the Company is $19,578,128 which will never be recovered. The regulatory lag attributable to the PCA reduces the Company's 2007 return on November 30, 2007 equity by 1.6%.

Q. What would the Company estimate the financial impact of the LGAR on 2008 assuming a "normal" condition for load growth?

A. As quantified in Mr. Said's direct rebuttal testimony, the Company expects that a "normal" 2008 condition would result in load growth of 273,425 megawatt-hours served at an additional expense of $7.9 million. In Mr. Said's direct testimony, the "embedded" cost, and thus what is collected, for both PURPA and non-PURPA variable power supply costs is $8.59 per MWh. The following quantifies the financial impact of the LGAR under the various proposals in this proceeding.

	2008 IPC	Staff	ICIP - Reading
Load Growth	273,425	273,425	273,425
Load Growth Adjustment Rate	$29.16	$62.79	$67.74
LGAR Charge	$6,795,450	$17,168,356	$18,521,810
LGAR Charge (After Jurisdictionalization and Sharing)	**$5,791,762**	**$14,632,590**	**$15,786,138**
Estimated Collection:			
Load Growth	273,425	273,425	273,425
Less estimated system losses	(21,874)	(21,874)	(21,874)
Estimated Sales	251,551	251,551	251,551
Idaho Jurisdictional %	94.7%	94.7%	94.7%
	238,219	238,219	238,219
"Embedded" Cost	$8.59	$8.59	$8.59
Estimated Collection	**$2,046,299**	**$2,046,299**	**$2,046,299**
Under Recovery	**($3,745,463)**	**($12,586,290)**	**($13,739,839)**

As presented above, LGAR immediately results in a detriment to the Company if LGAR is set at any value above "embedded" cost and the Company is experiencing growth. Even with IPC's proposed rate, the Company experiences a $3,745,463 loss while the rate proposed by Staff and Reading results in a more severe impact. In addition, the Company bears 10% of the $7.9 million cost to serve the additional load.

Q. Are you familiar with Staff witness English's testimony regarding FAS 87 and the removal of capitalized pension expense from rate base?

A. Yes.

Q. Please explain what FAS 87 is.

A. In 1985 the Financial Accounting Standards Board issued FAS 87. This standard required companies to record pension expense on an accrual basis rather than a cash basis. The standard also defined a methodology for calculating the net periodic pension cost [FAS 87 expense] that, in simplistic terms, reflects the current year's accrual of pension benefits by employees plus increases in the net present value of the obligation to pay benefits already accrued to employees less returns on investments held by the pension plan.

Q. What is your understanding of Mr. English's recommendations?

A. In his testimony Mr. English recommends the removal from rate base of $5,833,205 of pension costs the Company capitalized from 2003 through 2007, net of accumulated depreciation on that amount. He also recommends the removal of $162,316 from depreciation expense related to the annual depreciation of the capitalized FAS 87 pension costs he would remove from rate base.

Q. Do you agree with Mr. English's recommendation?

A. No. Mr. English's proposed reduction in rate base would result in a $5,833,205 write-off to Idaho Power's plant-in-service and a charge to 2008 income for that same amount.

Q. Do you believe it is appropriate for Staff to make a retroactive rate base adjustment extending back to 2003?

A. No. Staff is proposing to retroactively remove amounts previously included in rate base. An after-the-fact adjustment to prior periods is unreasonable because it requires that the Company go back in time to disallow amounts recorded in prior periods, creates a mismatch of expenses and revenues, and results in a retroactive adjustment to the Company's financial records that will be recognized as a reduction in 2008 earnings.

Q. Why did Idaho Power continue to capitalize a portion of pension expense under FAS 87 after the 2003 rate case?

A. Idaho Power is required to keep its books in compliance with the FERC's Uniform System of Accounts codified in the Code of Federal Regulations (CFR). The Idaho Commission has by order, adopted the FERC Uniform System of Accounts for Idaho regulatory accounting purposes. The Code of Federal Regulations prescribes that applicable pension expenses should be allocated to electric plant and capitalized.

Q. Mr. English asserts that in the 2003 rate case, the Commission intended to order Idaho Power to remove all FAS 87 pension expenses for rates. Do you agree?

A. No. In Order 29505, issued May 25, 2004, the Commission did not disallow any capitalized pension expense and did not remove depreciation expense related to capitalized pension costs, nor did it forbid the Company from capitalizing a portion of pension expense in future years. Had the Commission intended to disallow capitalized pension expense from rate base, one might have expected the Commission to order the removal of prior years' capitalized pension expense from rate base at the same time it denied recovery of FAS 87 expense. Had the Commission asked removal from rate base, the Company would then have had the opportunity to explain why it is proper to capitalize pension expense at that time and the effect upon the Company of such a removal requirement. The Company has complied with Order No. 29505 as it was written and issued by the Commission. Mr. English argues that he "believe[s] it was the Commission's intent to remove all of FAS 87 pension expense from rates." In fact the issue was never raised or addressed in the 2003 rate case and the final Order in this case was silent on the issue of capitalizing pension expense.

Q. Did the Commission state in Order No. 29505 that Idaho Power must remove capitalized pension *expense* from rate base or that Idaho Power would not be permitted to capitalize pension expense?

A. No. In Order 29505, the Commission ordered that the revenue requirement be reduced by the amount of pension *expense* to reduce the test year pension plan expenses to zero. No amount was required to be removed from rate base related to capitalized pension expense. Idaho Power did advise the Commission it had removed $2,014,489 from rate base for 2003 in its Notification of Computational Errors in Establishing the Company's Revenue Requirement filed with the Commission on June 11, 2004.

Q. Mr. English stated in his testimony that Staff was unaware that pension expense was being capitalized. Did Idaho Power intentionally conceal this information from the Commission?

A. Of course not. Idaho Power did not conceal this information from the Commission. Idaho Power has recorded pension expense to account 926200, which is a separate account used only for pension expense. It has been a long-standing practice of Idaho Power, and a standard industry practice based on the above cited CFR direction, to allocate amounts recorded in Account 926 to various other accounts, including construction work in process. Mr. English recognized this historic practice in his testimony on page 8, "Idaho Power routinely capitalizes a portion of its benefits as overhead." Likewise, Idaho Power's capitalization of pension overhead was a routine practice that was not hidden from the Commission.

Q. Do you agree with Mr. English's statement on page 9 of his testimony that, "The FAS 87 pension expense is an accrual of pension expense that the Company is required to record on its books for annual reporting purposes. It has no bearing on the amount of money the Company is required to contribute to the pension plan."

A. No. FAS 87 pension expense and the amount of money a company is required to contribute to the plan are not unrelated numbers. Both reflect costs to the company for operating the plan - one on an accrual basis and one on a cash basis. They are both impacted by the same factors - the amount of money invested to date and the returns on those investments, employee count and salary growth, etc. Furthermore, over the life of a pension plan, the amount of cash contributed to the pension plan and the amount of FAS 87 pension expense recorded (without respect to a capitalized portion) must be equal. While there are significant timing differences between the two amounts, it is disingenuous to imply that the two items are completely unrelated.

Furthermore, the flow of cash contributions by a company into a pension trust is not the best reflection of the cost of having a pension plan. The intent of a pension plan is to attract and retain employees. As employees work, they accrue benefits that must be paid to them at a future date. In reality this accrual of benefits occurs fairly smoothly with a generally increasing slope as inflation and employee growth slowly increase the rate at which these benefits accrue. In contrast, cash payments to a plan can be very lumpy and occur in some years, but not others based upon market returns, cash needs of the company and minimum funding requirements. Typically, the FAS 87 expense will more closely follow the smoother pattern of the accrual of benefits, but FAS 87 expense can also be somewhat variable due to variations in the return on plan assets and in actuarial assumptions. Despite the variability of these two measures, it must be recognized that employees continue to accrue additional benefits through their service to the company that must ultimately be paid to those employees in future years. Mr. English's contention that, since a company is not currently making contributions to its pension plan, it therefore does not incur a cost from operating that plan, is to ignore the economics of the plan.

Q. Setting aside for the moment the issue of previously capitalized pension expense, what is the Company's current practice regarding current and future pension costs?

A. On June 1, 2007, the Commission issued Order 30333. This Order clarified that the Company should seek recovery of future pension costs on a cash basis, or when future contributions are made to the plan. Pursuant to this Order, the Company began deferring FAS 87 pension expense to a regulatory asset in August of 2007. As a result, until the Company makes contributions to the plan, it will not record a charge to earnings for FAS 87 pension expense nor will it capitalize a portion of FAS 87 pension expense to plant. Prior to August of 2007, the Company had a prepaid asset relating to previous contributions made to the pension plan. As the Commission's Order only relates to future contributions to the plan, the Company could not begin deferring FAS 87 pension expenses until the previously made contributions had been fully amortized through expense.

Q. In your opinion is inclusion of the capitalized portion of pension in rate base consistent with prior commission orders and accepted regulatory accounting procedures?

A. Yes. The Company treatment is consistent with both FAS 87, the FERC Uniform System of Accounts and generally Accepted Accounting Principles (GAAP).

Q. Staff Witness English, at pages 12-15 of his testimony states that he has adjusted the actual test year operating payroll in a manner that is consistent with treatment in prior Commission orders. Do you agree with this adjustment?

A. No. As I have stated, the Company's annualization of year-end payroll of the forecast test year for 2007 is representative of the reasonable expenses the Company expects to incur during the effective rate period of the forecast test year. Although his use of annualization is consistent with prior Commission orders, Mr. English has applied the payroll adjustment to an incorrect test period, given the Commission's responsibility to set rates that reasonably provide the Company an opportunity to earn its allowed rate of return.

Q. Staff Witness English does not include a known and measurable adjustment for a 2008 salary structure adjustment. Likewise, Micron witness Dr. Peseau states on page 23 of his testimony that "I take issue with the Company's request to raise its revenue requirement by $3,020,719 to account for a 2008 salary structure adjustment". Have they correctly analyzed the 2008 payroll issue?

A. No. The forecast test year for 2007 was compiled to reflect the Company's expected operating and capital costs to reliably serve its Idaho customers and to minimize the regulatory lag associated with the historical and hybrid test years previously used by the Company. A standard adjustment to establish the revenue requirement in a rate proceeding is to identify those known and measurable adjustments to expenses, such as payroll. The impact of this known and measurable adjustment is to establish the expected expense representative of the effective rate period. The Commission must determine the appropriate expense timeframe to apply the consistent adjustment that has been included in prior cases. Mr. English and Dr. Peseau suggest totally removing an increase in expense that has already been implemented effective December 15, 2007 and will impact the rate effective period in 2008.

Q. Staff Witness Vaughn describes at pages 10-11 an adjustment to the Staff's actual test year for a credit received from the Federal Energy Regulatory Commission (FERC) involving FERC administration and Other Federal Agency (OFA) charges. Do you agree with this adjustment?

A. No.

Q. Please describe what the FERC administration and other federal agency charge reimbursements were for and the period of time that was involved in accumulating the overcharge.

A. The FERC and other federal agencies assess utilities for costs related to their administrative and regulatory duties. Numerous utilities sued over the accuracy of the charge and as a result, Idaho Power received reimbursement for fees collected from 1999 through 2006.

Q. Ms. Vaughn recommends that the Company flow through this reimbursement to its customers over a five year period. Do you agree with this recommendation?

A. No. There are essentially two reasons for my disagreement: (1) Ms. Vaughn contends that the Company over-collected its expenses in prior years. This would only be true if the Company had over earned since the period of time she uses i.e. from 2003 forward. As Company witness Steve Keen has demonstrated in his rebuttal testimony, the return on equity for those time periods was well below the allowed return established in those two cases and accordingly there was no overcharge. (2) Ms. Vaughn has simply selected one expense item out of many to make a retroactive adjustment for ratemaking purposes. She is artificially increasing the Company's revenues for the next five years when she creates the amortization of her created credit. This amortization has no relationship to the actual ongoing costs of the Company. It will simply cause the

Company to under-earn through the device of creating a revenue stream from a prior period by assuming that the Company has over-collected on an expense item for a prior period.

Q. What would be the financial impact of Ms. Vaughn's recommendation?

A. The Company would be required to write-off approximately $3.3 million to its 2008 income.

Q. Staff Witness Vaughn concludes between pages 12-19 that the actual test year revenue requirement should be reduced by $879,887 based on an accumulation of assumptions and projections related to the Company's employee use of Purchasing Cards (P-card). Do you agree with this adjustment?

A. No. Ms. Vaughn has not done a complete review and analysis with a statistically reliable sample. Her conclusions are based on inferences about the sample that she selected. She admittedly ignores the deductions in my Exhibit No. 17 that have been consistent with prior cases in the future test year filed by the Company and she arbitrarily adjusts the actual test year expense for personal vehicle mileage by 50%. To suggest making adjustments to lower the actual test year revenue requirement by $879,887 based on this substantially unsupported analysis is improper. I recommend the

Commission make no adjustment based on Staff witness Vaughn's analysis.

Q. On pages 9-11 of her testimony, Staff Witness Stockton suggests working capital adjustments for prepaid items and aligns the fuel stock inventory to reflect normalized operating criteria. Do you agree with these adjustments to the actual test year?

A. I agree that Ms. Stockton's mechanical adjustment of the Company's working capital to match Staff's proposed test year was done correctly, but I do not believe Staff's test year appropriately reflects the Company's costs during the period rates will be in effect.

Q. Dr. Peseau recommends on pages 23-24 of his testimony that the Commission deny $2.2 million of the Company's proposed revenue adjustment for IERCo. Is that an appropriate adjustment?

A. No. The $2.2 million Dr. Peseau refers to is additional revenues that IERCo received in 2006 as a result of increased production experienced at Bridger Coal Company (one-third ownership by IERCo) which was needed to make up for reduced deliveries from Black Butte Coal Company. This was strictly a 2006 event and has not reoccurred in 2007.

Dr. Peseau's only justification for this adjustment is that "parties are obviously still unable to assess this prediction". In other words, Dr. Peseau is asserting that the Company's forecast of IERCo's 2007 revenues and resulting net income could not be relied upon. The facts do not support Dr. Peseau's conclusion. For the 11 months ending November 2007, IERCo has recorded $4.6 million of net income. To test the accuracy of the Company's forecast, a simple annualization can be completed. By annualizing the $4.6 million, the projected 2007 net income equals $5.0 million in net income. In the Company's 2007 forecasted test year, IERCo's net income was estimated to be $5.2 million. Additionally, Staff has included the Company's 2007 forecast of IERCo's net income in its proposed revenue requirement.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

Idaho Power Company
Regulatory Lag: O&M Analysis

Other O&M (2007 Forecast Test Year)	$288,932,502
Less:	
DSM *(Schwendiman, Exhibit 25)*	(15,732,910)
Pension *(Schwendiman, Exhibit 25)*	(4,607,443)
Other O&M before Adjustments	268,592,149
Adjustments (Smith, Exhibit 18):	
Annualized Payroll	4,500,064
2008 Payroll SSA	3,020,719
Incentive Expense	229,859
Adjusted Other O&M (2007 Forecast Test Year)	276,342,791
Assumed Sales Growth (1)	4,974,170
Estimated Collection in 2008 (2)	281,316,961
2008 Approved Budget excluding DSM	288,639,200
Regulatory Lag	($7,322,239)

(1) Assumes a 1.8% growth in normalized sales from 2007 to 2008.
(2) Assumes new rates are in effect January 2008.

Idaho Power Company
Regulatory Lag: O&M Analysis

Other O&M per Staff Exhibit 113	$558,975,639
Less:	
Acct 501	119,484,800
Acct 547	7,085,900
Acct 555	150,364,531
Other: Unidentified by Staff	481,020
Other O&M (12 months ending June 2007)	$281,559,388
Staff Adjustments per Staff Exhibit 113 (1)	
Standard Commission Adjustments	(22,234,882)
Donn English Adjustments	8,661,379
Cecily Vaughn Adjustments	1,913,235
Total Staff Adjustment	(11,660,268)
Adjusted Other O&M (Staff)	269,899,120
Assumed Sales Growth (2)	4,858,184
Estimated Collection in 2008 (3)	274,757,304
2008 Budget excluding DSM	288,639,200
Regulatory Lag	($13,881,896)

(1) Including Staff adjustments in this analysis is only for demonstrating regulatory lag. This should not construed as my agreement with these adjustments.
(2) Assumes a 1.8% growth in normalized sales from 2007 to 2008.
(3) Assumes new rates are in effect January 2008.

Idaho Power Company
Regulatory Lag: Load Growth Adjustment within the PCA (2001 through November 2007)

	1 2001	2 2002	3 2003	4 2004	5 2005	6 2006	7 YTD Nov 2007
Test year used for normalized sytem load	*1993*	*1993*	*1993*	*1993 and 2003 Jan-May/Jun-Dec*	*2003*	*2003 and 2005 Jan-May/Jun-Dec*	*2005*
Actual Total System Load (Adjusted)	15,391,462	15,789,544	15,146,843	14,700,152	14,563,423	15,302,912	14,491,928
Total System Normalized Load - MWh	13,952,283	13,952,283	13,952,283	14,232,387	14,107,573	14,506,197	13,545,044
Change in Load (MWhs)	1,439,179	1,837,261	1,194,560	467,765	455,850	796,715	946,884
Load Growth Adjustment Rate	$16.84	$16.84	$16.84	$16.84	$16.84	$16.84	$16.84 / $29.41 2
LGAR Charge (After Jurisdictionalizaton and Sharing)	**$18,540,367**	**$23,668,699**	**$17,036,571**	**$6,511,097**	**$6,501,240**	**$11,362,587**	**$22,072,707**
Estimated Collection:							
Change in Load (MWhs)	1,439,179	1,837,261	1,194,560	467,765	455,850	796,715	946,884
Less estimated system losses at 8%	(115,134)	(146,981)	(95,565)	(37,421)	(36,468)	(63,737)	(75,751)
	1,324,045	1,690,280	1,098,995	430,344	419,382	732,978	871,133
Idaho Jurisdictional %	85.0%	85.0%	85.0%	85.0% / 94.1%	94.1%	94.1%	94.1%
	1,125,438	1,436,738	934,146	388,636	394,638	689,732	819,736
Embedded PURPA & Variable Power Supply Expense Rate	$5.24	$5.24	$5.24	$5.24 / $6.67	$6.67	$6.67 / $6.81	$6.81
Estimated Collection of PURPA & Variable Net Power Supply Cost	$5,897,295	$7,528,508	$4,894,925	$2,724,393	$2,632,239	$5,059,907	$5,582,405
Earnings (Loss) before Tax	**($12,643,072)**	**($16,140,191)**	**($12,141,646)**	**($3,786,704)**	**($3,869,001)**	**($6,302,679)**	**($16,490,302)**
Cumulative 2001 through 2007 Earnings (Loss) before Tax	**($71,373,596)**						