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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 RATES AND CHARGES FOR ELECTRIC SERVICE TO ELECTRIC CUSTOMERS IN THE STATE OF IDAHO.	CASE NO. IPC-E-07-08

IDAHO POWER COMPANY

DIRECT REBUTTAL TESTIMONY

OF

GREGORY W. SAID

Q. Please state your name.

A. My name is Gregory W. Said.

Q. Are you the same Gregory W. Said that previously submitted direct testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. I will address what I believe are incorrect or inappropriate assumptions and conclusions related to the "matching" of test year 1) rate base, 2) expenses and 3) revenues contained in the testimonies of Commission Staff Witnesses Lobb and Carlock and Micron Witness Peseau. I will discuss how the directions given to other Staff witnesses by Mr. Lobb and Ms. Carlock were inconsistent, resulting in erroneous computations in the Staff's determination of the Company's revenue requirement as contained in the testimony of Staff Witnesses English and Stockton. I will respond to Ms. Carlock's contention that the Company did not adequately address the impact of regulatory lag. I will respond to Staff Witness Sterling's assertion that high gas prices benefit Idaho Power's customers. I will address Staff Witness Hessing's load growth adjustment recommendations. Finally, I will discuss how the combination of recommendations made by the Staff witnesses, if accepted by the Commission, will result in rates that will preclude the Company from an opportunity to earn a fair rate of return as required by law.

Q. At page 15 of her testimony, Staff Witness Carlock states that "the matching principle is another long established, ratemaking concept where costs and revenues must match." Do you agree with Ms. Carlock's statement?

A. Yes. However, I believe the Staff has incorrectly matched revenues, expenses and rate base in its proposed July 1, 2006 through June 30, 2007 test year.

Q. Please describe how the Company went about matching costs and revenues in its filed 2007 test year.

A. The Company forecasted revenues for the 12 months ending December 2007 and expenses for the 12 months ending December 2007 based upon plant forecasted to be in service by the end of December 2007 with annualization to reflect plant as if it was in service for the entire year. Normalized power supply expenses were determined for the 2007 test year reflecting annualized generation plant in service and annualized power supply contracts, including the Horizon Wind project which was originally scheduled to be on-line on January 1, 2008. The Horizon Wind project actually began providing electricity on November 27, 2007 and was fully operational on December 28, 2007. The Company also included an annualizing adjustment for a general wage adjustment of 3 percent which in reality became a 3.25

percent increase implemented on December 15, 2007. The Company included no investments, expenses, or revenues beyond January 1, 2008, so rates established in 2008 as a result of this proceeding will be ultimately based upon a period that is historic to the time the rates will be in effect.

Q. Please describe your understanding of how the Staff matched expenses, revenues and rate base in its July 2006 through June 2007 test year.

A. The Staff accepted the Company's forecasted revenues for the 12 months ending December 2007, but "matched" those revenues with expenses for the 12 months ending June 2007. The only exception to this "matching" was in the area of power supply expenses. Staff's power supply expenses were initially similar to the Company's forecast of power supply expenses for a test year ending December 2007, but Staff reduced these expenses by $6 million from the Company's estimate for reasons unrelated to matching. Other than power supply expenses, no other expenses were adjusted to reflect changes beyond June 2007. In fact, some expenses in Staff's test year were further reduced based upon Staff adjustments. Plant additions of greater than $2 million beyond June 2007 were "proforma" adjusted into the test year, but again no corresponding expenses were included. The power supply expense associated with the purchase of energy from the Horizon wind project was included in the Staff's test year expenses, but the general wage adjustment was not.

Q. Would you describe the Staff test year methodology as being consistent with the matching principal Ms. Carlock described in her testimony?

A. No. Staff reaches forward in time to capture the revenue growth envisioned in the Company's test year ending December 2007, but only reaches forward in time to capture a portion of expenses related to fuel and purchased power. This mismatch drives down the Company's revenue requirement by artificially understating expenses necessarily incurred to produce the additional revenues that Staff included.

Q. What percentage of total expenses are fuel and purchased power expenses?

A. From the data contained in the Company's filing, fuel and purchased power expenses in 2006 were approximately $398.5 million out of $753.8 million total operating expenses or 52.9 percent. Corresponding values from the Company's 2007 test year are normalized fuel and purchased power expenses of $278.2 million out of $672.3 million total operating expenses or 41.4 percent.

Q. Mr. Lobb states on page 16 of his testimony that "including variable power supply costs in revenue requirement more than offsets new customer revenue". Do you agree?

A. No. This statement suggests that "matching" has been achieved when only 41.4 percent of expenses are updated to year-end levels while 100 percent of revenue changes by year-end are captured. Ignoring increases in 58.6 percent of total expenses while including 100 percent of revenue increases is counter to Staff's stated objective of proper matching.

Q. When referring to plant additions, Mr. Lobb states on page 10 of his testimony that "post-test year additions have been included in the test year as if they have been in service for the entire period." Is this a correct representation of what Staff has done?

A. No. What Mr. Lobb describes is usually referred to as "annualization" and is a common ratemaking convention that this Commission has regularly accepted in the past. However, the Staff did not annualize plant additions to represent those additions as if they had been in service for the entire period. Instead, as described in Ms. Carlock's testimony on page 15, "Plant placed in service beyond the test year ending June 30, 2007 has been proformed into the results of operations to match the in service date between July and December, 2007." As a result, plant additions are reflected in rate base for only a portion of a year, for example 2 out of 12 months. Reflecting plant in service for only a portion of the test period is inconsistent with prior Commission direction[1] and counter to Mr. Lobb's stated direction (Lobb Direct page 13 lines 19-23) to continue using a methodology previously approved by the Commission to address the Company's desire to reduce regulatory lag.

Q. Dr. Peseau, at page 22 of his testimony states that "Idaho Power adds more to rate base than the total capital expenditures on those assets, by assuming they are in service for 15 months of a 12 months test period." Is he correct?

A. No. It is unclear how Dr. Peseau came to this conclusion, but the Company only reflected assets as if they were in service for the full 12 month period of the test year.

Q. Ms. Carlock states on page 17 of her testimony that "the need to further reduce regulatory lag in this case is also not adequately addressed in this case." Is Ms. Carlock accurately describing the record in this case?

A. No. Ms. Carlock ignores Exhibit 31 which is the Company's quantification of a 2008 revenue requirement, based on an assumption of Commission approval of the

[1] Order No. 29505 issued in Case No. IPC-E-03-13, May 15, 2004.

Company's 2007 revenue requirement. I presented Exhibit 31 in my direct testimony in this case. Restating the conclusion from my direct testimony, rates for 2008, based upon the 2007 test year, will be inadequate for the Company to earn its authorized rate of return under normal conditions with revenues falling $23.3 million short of the 2008 revenue requirement. Ms. Carlock does not address this quantification or the underlying analyses contained in Exhibit 31.

Q. Micron witness Peseau states that "Mr. Said acknowledges, if Idaho Power's proposed rates go into effect on January 1, 2008, those rates would produce annual revenues of $695,423,270, roughly $14,000,000 more than its claimed revenue requirement." Do you agree with this statement?

A. No. As I have just stated, 2008 revenues would fall short of the 2008 revenue requirement by $23.3 million. Dr. Peseau's characterization of my statements is a comparison of 2008 revenues to a 2007 revenue requirement, something that I did not do in my testimony.

Q. Dr. Peseau goes on to state that based upon this $14 million difference between 2008 revenues and the 2007 revenue requirement, the Company would be overearning from the first day rates would go into effect. Please comment.

A. Dr. Peseau is wrong in his conclusion. He quotes from his Exhibit 502, the report to the Iowa legislature from the Iowa Utilities Board, as to the importance of matching costs and revenues, but then engages in the same mismatch behavior as Staff. He compares the revenues from one period (2008) to the revenue requirement of a different period (2007). Simply stated, revenue requirement is equal to the expenses associated with a particular test year plus a return component on assets held during the same test year. Comparing one year's revenue to a separate year's revenue requirement is a clear mismatch. Another error in Dr. Peseau's assessment set out on page 6 of his direct testimony is his statement that increased revenues received throughout 2008 as a result of load growth in 2008 must be offset by an equal amount of expenses "in a single day" in order for the Company not to overearn its revenue requirement. Suggesting that an *annual* revenue change must be offset by a one-day expense change is another clear mismatch.

Q. Have you reviewed the revenue requirement quantification performed by Staff Witness English?

A. Yes, I have.

Q. Please describe the differences between the Staff quantification of the Idaho jurisdictional revenue requirement and the Company quantification of the Idaho jurisdictional revenue requirement.

A. As an aid to my description of the differences between the Staff quantification of the Idaho jurisdictional revenue requirement and the Company quantification of Idaho jurisdictional revenue requirement, I prepared Exhibit 66 as a reference tool. I have simplified the Idaho jurisdictional revenue requirement quantification into four primary drivers: 1)rate base, 2)rate of return, 3)expenses, and 4) revenues. Referring to row 1 of Exhibit 66, Staff has quantified test year Idaho jurisdictional rate base to be $1.81 billion while the Company has quantified test year Idaho jurisdictional rate base to be $1.88 billion, a difference of $74.8 million. Row 2 of Exhibit 66 shows the Staff recommendation of a 7.864 percent overall rate of return compared to the Company recommendation of an 8.561 percent overall rate of return. Multiplying the Idaho jurisdictional rate base by the recommended overall rate of return produces the recommended Idaho jurisdictional return component of revenue requirement. As shown on line 3 of Exhibit 66, the Staff quantifies an Idaho jurisdictional return of $142.2 million based upon the rate base and rate of return drivers while the Company quantifies an Idaho jurisdictional return of $161.2 million based upon the same two drivers of revenue requirement.

Line 4 of Exhibit 66 shows the Staff quantification of the third revenue requirement driver, Idaho jurisdictional expenses, as $669.4 million while the Company quantification of Idaho jurisdictional expenses is $678.9 million, a difference of $9.6 million. The final revenue requirement driver, revenues, is shown on line 5 of Exhibit 66. Staff and Company quantifications of revenues, because they are both based upon the same time frame, calendar year 2007, are essentially identical at $801 million. The revenue numbers reflect the Idaho jurisdictional allocation of 1) firm jurisdictional sales, 2) system opportunity sales, 3)other operating revenues and 4) IERCo operating income.

The remainder of the rows on Exhibit 66 are entirely computational. Line 6, net income, is equal to line 5, revenues, minus line 4, expenses. Line 7, the earnings deficiency, is equal to line 3, return minus line 6, net income. Line 8 is the constant, 1.642, which is the net-to-gross tax multiplier. Line 9, the Idaho jurisdictional revenue deficiency is equal to line 7, the earnings deficiency times line 8, the net-to-gross tax multiplier (the amount it takes to make the Company whole for income tax purposes). The Staff quantifies the Idaho jurisdictional revenue deficiency as $17.5 million while the Company quantifies the Idaho jurisdictional revenue deficiency as $63.9 million.

Q. What are the primary reasons for the difference between the Staff's computation of Idaho jurisdictional rate base and the Company's computation of Idaho jurisdictional rate base?

A. I have identified three primary reasons that the Staff's computation of Idaho jurisdictional rate base is different from the Company's computation of Idaho jurisdictional rate base. The first reason, as I have previously discussed, is that while Mr. Lobb states that he directed his staff to include post-test year rate base additions in the test year as if they have been in service for the entire period, Ms. Stockton did not do so. The second reason is that the Staff has recommended the removal of previously capitalized pension benefits. The third reason, as I have also previously discussed, is the mismatching of rate base to revenues.

Q. Have you quantified the impact on Idaho jurisdictional rate base of Staff Witness Stockton's failure to annualize post test year rate base additions in a manner consistent with previous Commission orders and Mr. Lobb's stated direction?

A. Yes. Under my direction and supervision, Exhibit 67 was created to quantify the impact on Idaho jurisdictional rate base if Ms. Stockton had annualized post test year rate base additions in a manner consistent with previous Commission orders and Mr. Lobb's stated direction. Correcting for the Staff's incorrect annualizing adjustments would add $45.4 million to rate base.

Q. Have you quantified the impact on Idaho jurisdictional rate base of the Staff recommendation to exclude previously capitalized pension benefits from Idaho jurisdictional rate base?

A. Yes. Under my direction and supervision, Exhibit 68 was created to quantify the impact on Idaho jurisdictional rate base if Staff had followed prior practice and included previously capitalized pension benefits in Idaho jurisdictional rate base. Inclusion of previously capitalized pension benefits would add $5.4 million to Idaho jurisdictional rate base.

Q. After correcting for the Staff's incorrect annualizing of rate base additions and quantifying the impact of excluding previously capitalized pension benefits from rate base, what is the remaining difference in quantification of Idaho jurisdictional rate base that you attribute to mismatching?

A. Of the $74.8 million difference between the Staff and Company quantifications of Idaho jurisdictional rate base, $45.4 million is the result of the Staff's annualization error, $5.4 million is the result of the Staff recommendation to exclude previously capitalized pension benefits, and the remainder, $24.0 million is the result of Staff mismatching rate base with revenues.

Q. Has the Company completed its accounting for electric plant in service as of November 2007?

A. Yes. Ms. Smith has informed me that the electric plant in service balance as of November, 2007 is *greater* than the amount the Company constructed as the end-of-test year 2007 electric plant in service balance in Exhibit 30.

Q. Does the end-of November 2007 electric plant in service balance suggest that the Company's 2007 test year rate base amount is appropriate?

A. Yes, the higher level for the actual November 2007 electric plant in service balance suggests that the Company's forecast of 2007 rate base is appropriate. In fact, the Company's forecasted test year rate base is probably too low.

Q. Based on this information what should the Commission conclude with regard to the appropriate Idaho jurisdictional rate base?

A. At a minimum, the Commission should correct for the Staff error in annualization of rate base additions. In addition, the Commission should consider Company witness Smith's testimony supporting the inclusion of previously capitalized pension benefits in rate base and finally, the Commission should consider Company witness Smith's rebuttal testimony describing the accuracy of the Company's forecasted 2007 test year rate base when compared to actuals to date in 2007 to appropriately match test year rate base to test year revenues. Simply by correcting these three errors in the differences between the Staff's quantification of the Idaho jurisdictional rate base, the Commission should arrive at a value near $1.88 billion for Idaho jurisdictional rate base.

Q. What should the Commission conclude with regard to the appropriate rate of return for the Company?

A. Staff's quantification of the appropriate overall rate of return is 7.864 percent. The Company's application requested an overall rate of return of 8.561 percent. Mr. Steve Keen and Mr. Avera have pointed out the shortcomings of Staff's proposed rate and the Commission should conclude that an overall rate of return closer to 8.561 is appropriate.

Q. Has Mr. Steve Keen identified additional Staff mismatching with regard to the overall rate of return?

A. Yes. Mr. Steve Keen has informed me the Staff has mismatched capital structure costs. Those mismatches are discussed by Mr. Steve Keen.

Q. What are the primary reasons for the $9.6

million difference between the Staff's computation of Idaho jurisdictional test year expenses and the Company's computation of Idaho jurisdictional test year expenses?

A. I have identified two primary reasons for the $9.6 million difference between the Staff's computation of Idaho jurisdictional test year expenses and the Company's computation of Idaho jurisdictional test year expenses. The first is the Staff recommendation that test year normalized power supply expenses be reduced by $6 million. The remaining $3.6 million is related to Staff's mismatch of expenses to rate base and revenues.

Q. Mr. Sterling states on page 4 of his testimony that "High gas price actually benefit Idaho Power and its ratepayers in most years." Is he correct?

A. No. It is inappropriate to suggest that the Company or its customers benefit from rising gas costs at the same time that the Company is adding natural gas-fired generation resources to its system in order to provide adequate service in the future. Mr. Sterling does, however, recognize that gas price assumptions included in AURORA power supply simulations are a primary driver of modeled market prices for electricity. The Company has repeatedly stated and the Commission has repeatedly recognized that within the Northwest, hydro conditions are also a primary driver of market prices for electricity.[2] Low water conditions, droughts, tend to drive electricity prices in the Northwest up while abundant water tends to drive electricity prices in the Northwest down. The Company believes that AURORA modeling considers the gas price influence on electric market prices too heavily and the water condition influence on electric market price too lightly. In order to correct for this modeling deficiency, the Company differentiates gas price assumptions by water condition. Mr. Sterling has removed this differentiation suggesting that "Idaho Power assumed high gas prices are associated with low water conditions and that low gas prices occur when water conditions are high." The Company has been open and forthright in stating that this is not the Company assumption, but rather a means of correcting for a modeling deficiency.[3] Because AURORA modeling does not adequately reflect water condition impacts on electric market prices, higher gas price assumptions result in higher projected market prices under all conditions. This results in artificially high surplus sales revenues which reduce the Company's revenue requirement. This may be why Mr. Sterling believes that high gas prices are a benefit to Idaho Power's customers. In my opinion, by taking advantage of this

[2] Order No. 24806 issued in Case No. IPC-E-92-25 and Order No. 30047 issued in Case No. IPC-E-06-07 are two examples.

[3] See pages 6 and 7 of Greg Said's direct testimony in Case No. IPC-E-03-13.

AURORA modeling deficiency, Staff is looking solely for an opportunity to reduce the quantification of normalized power supply expenses rather than to properly quantify normalized power supply expenses.

Q. Please describe the remaining $3.6 million difference in quantification of test year expenses that you characterize as a result of mismatching expenses to rate base and revenues.

A. Some of the mismatching of expenses are related to Staff witness Vaughn's removal of expense items which are addressed by other Company rebuttal witnesses and the remainder of the mismatching results from necessary adjustments to expenses that would result from correction to the annualization of plant additions that I discussed earlier in my rebuttal testimony.

Q. Please explain how a change in rate base effects a change in expenses as well.

A. An example of how a change in rate base effects a change in expenses is the effect of annualization on depreciation. As a result of annualizing post-test year rate base additions in the test year as if they have been in service for the entire period, monthly depreciation expenses change to correspond to the annualization of rate base.

Q. What should the Commission conclude with regard to the appropriate level of test year expenses?

A. Staff quantified the appropriate level of test year expenses to be $669.3 million. The Company quantified the appropriate level of test year expenses to be $678.9 million. The Commission should reject Mr. Sterling's adjustment to the power supply expenses as filed by the Company and should approve expenses equal to the Company proposed level to correct for incorrect annualization and matching problems contained in Staff recommendations.

Q. Are there any mismatches of expenses and revenues related to taxes that have not been addressed by you or any other Company witnesses?

A. Yes, I consulted with Idaho Power's Corporate Tax Director, Gene Marchioro. He informed me that Ms. Stockton utilized many of the Company's test year tax computations which are specific to the Company's filed test year and matched them inappropriately with Staff's proposed test year. Mr. Marchioro informed me that federal income taxes, interest charges, IERCO taxable income, the Idaho Investment Tax Credit Adjustment were all based upon the Idaho Power filed test year and are inappropriately used by Staff.

Q. Are there any other errors contained within the Staff quantification of expenses that you would like to mention?

A. Yes. Review of Staff Exhibit 113 revealed that Staff removed $15.7 million of DSM related expenses. However, in Staff's 13 month beginning balance, there was only $4.7 million of Demand Side Management (DSM) expense. In short, Staff removed $11.0 million more than what existed.

Q. What should the Commission conclude with regard to the appropriate level of test year revenues?

A. Provided that the Commission adjusts rate base and test year expenses to match, the $801.2 million of revenues proposed by the Company are appropriate for the revenue requirement determination.

Q. At page 16 of his testimony, Staff Witness Hessing states the Company proposes "use of an incremental cost approach" to the load growth adjustment rate determination "instead of the marginal cost approach required by the Commission in its final order in Case No. IPC-E-06-08." Have you reviewed the final order Mr. Hessing is referring to?

A. Yes. That order is Order No. 30215.

Q. What was the Company's request in Case No. IPC-E-06-08?

A. The Company requested a change in the methodology used to determine the load growth adjustment rate (LGAR) within the power cost adjustment (PCA).

Specifically, the Company requested that the LGAR be based upon embedded costs.

Q. Did the Commission approve a change in methodology to determine the load growth adjustment rate based upon embedded costs?

A. No. As Mr. Hessing has pointed out in his testimony, the Commission ordered that the load growth adjustment rate should be determined using updated marginal cost analysis studies.

Q. Does Order No. 30215 definitively establish what the Commission meant by the term "marginal cost analysis studies"?

A. No. On page 3 of Order No. 30215, the Commission states "The current load growth adjustment multiplier of $16.84/MWh used in the PCA true-up calculation is a marginal cost based rate determined in 1993 when the PCA was instituted. It was calculated by averaging the fuel costs of the Company's two highest operating cost base-load resources, Boardman and Valmy, which were the Company-owned resources deemed in 1993 most likely to be dispatched to meet additional loads."

Later on page 3, the Commission states "Alternatively, the Company proposes a load adjustment factor of $17.15, a number that reflects the marginal cost of Company-owned resources and the occasional operation of the Company's combustion turbine units."

On page 5 of Order No. 30215, the Commission discusses "a marginal cost approach that compares two AURORA runs of power supply expenses".

Based upon my reading of Commission Order No. 30215, the Commission recognized a number of "marginal" cost analysis study methodologies.

Q. Do you believe that the Company's recommendation of a $29.16 per megawatt-hour load growth adjustment rate based upon what you have referred to as an "incremental cost analysis" is consistent with the Commission intent when it directed the Company to use a "marginal cost analysis"?

A. Yes. Mr. Hessing assumes that only one marginal cost analysis method exists even though a number of marginal cost analysis methodologies are referenced in Order No. 30215. The specific marginal cost analysis methodology that I described in my direct testimony in this case is the marginal cost analysis method recommended by Mr. Hessing. However, in my opinion, the incremental cost methodology that I also described in my direct testimony should also be considered a marginal cost analysis consistent with the intent of Order No. 30215.

Q. Does Mr. Hessing discuss the revenue impact on the Company of serving additional load?

A. Yes, at page 10 of his testimony, Mr. Hessing points out that residential revenues "near 6¢/kWh" and high load factor class revenues at "about 3¢/kWh" would not offset marginal power supply costs at over 6¢/kWh ($60/MWh). If the Commission adopts Mr. Hessing's recommendation for the load growth adjustment rate, the Company will find itself in the bizarre situation of crediting customers through the PCA at a rate that is *greater* than the revenue that it receives from any customer class other than small general service customers. Crediting customers at a rate that is greater than what they pay while at the same time requiring the Company to serve those same customers using power supply resources that are more expensive than average system cost is irrational and severely damages the Company's opportunity to earn its authorized overall rate of return.

Q. Based upon Mr. Hessing's recommendation of a $62.79 per megawatt-hour load growth adjustment rate, what would the Company estimate the impact to be given a "normal" 2008 condition?

A. As per my direct testimony in this case, based upon the information contained in Exhibit 36, 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. A load growth adjustment rate of $62.79 per megawatt-hour would remove

$17.2 million (273,425 megawatt-hours * $62.79 per megawatt-hour = $17,168,356) from PCA consideration. This $17.2 million adjustment would remove $9.3 million more than the incremental cost of serving load growth.

Q. How does this $17.2 million PCA adjustment compare to the Staff recommendation for a revenue increase in this case?

A. Staff recommends a general rate increase in Idaho that would increase jurisdictional revenues by $17.5 million, but a load growth adjustment rate that will immediately remove $17.2 million of recovery from the PCA mechanism in 2008. This is not a rational result.

Q. Looking at the combination of Staff's recommendations in this case, in your judgment will the Company be able to earn a fair rate of return as required by law?

A. In my opinion, no. I have stated in my direct testimony, based upon anticipated growth in rate base and expenses, even with approval of Company proposed rates, the Company would expect to fall short of its authorized overall rate of return under normal conditions. As shown on page 1 of Exhibit 31, the Company would expect to earn a 7.86 percent overall rate of return, 0.7 percentage points below an authorized 8.56 percent overall rate of return. Establishing a test year revenue requirement based on inappropriate annualization and mismatched rate base, expenses and revenues as proposed by Staff results in further erosion of the Company's ability to recover its authorized overall rate of return. Add to that the Staff's proposed load growth adjustment rate, which removes power supply expenses at a rate that is greater than the rate at which the Company receives additional revenues from load growth, and it is virtually certain that the Company will not have an opportunity to earn a fair overall rate of return.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

1	2 Staff	3 Company	4 Gap
1 Rate Base	1,807,849,061	1,882,670,920	74,821,859
2 Rate of Return	7.864%	8.561%	
3 Return	142,171,058	161,175,457	19,004,399
4 Expenses	669,364,817	678,949,369	9,584,552
5 Revenues	800,906,946	801,181,308	274,362
6 Net Income	131,542,129	122,231,939	
7 Earnings Deficiency	10,628,929	38,943,518	28,314,589
8 Tax Multiplier	1.642	1.642	
9 Revenue Deficiency	17,452,701	63,945,257	46,492,556

Idaho Power Company
Rate Base Additions

Line No.	1 Description	2 IPUC Adjustment	3 Corrected Annualization	4 Difference	5 Annual Depreciation Reserve Adjustment	6 Net System Correction	7 Allocation Source	8 Allocation % Idaho	9 Idaho Jurisdictional Correction
	Distribution								
	Stations:								
1	Cartwright Substation		1,698,978	1,698,978	(22,936)	1,676,042	DA362S	95.75%	1,604,810
2	Pole Line Substation- New 138k	182,121	2,185,454	2,003,333	(27,045)	1,976,288	"		-
						-			-
	Transmission					-			-
	Lines:					-			-
3	HRFT-STKY 138 KV Right of way and build 35 miles of new line	-	99,336	99,336	(1,341)	97,995	D11	86.26%	84,530
4	Starkey-Jump 138 kV, 28 miles	1,863,170	11,179,019	9,315,849	(125,764)	9,190,085	"	86.26%	7,927,367
5	STKY-JUMP Build 28 miles 138 k	2,135,314	8,541,255	6,405,941	(86,480)	6,319,461	"	86.26%	5,451,167
6	JUMP-LKFK CONSTRUCT NEW 138 KV	1,253,916	5,015,665	3,761,749	(50,784)	3,710,965	"	86.26%	3,201,079
7	Construct new 3 mile tap to N.		1,025,034	1,025,034	(13,838)	1,011,196	"	86.26%	872,258
						-			-
	Stations:					-			-
8	BUILD 230/138-13KV STATION	898,275	3,593,100	2,694,825	(36,380)	2,658,445	D11	86.26%	2,293,175
9	Brownlee 75 Mvar 230 kV Shunt		583,040	583,040	(7,871)	575,169	"	86.26%	496,141
10	Elkhorn Wind Generation - Tran	328,685	3,944,219	3,615,534	(48,810)	3,566,724	"	86.26%	3,076,656
11	EMS/Advances application project	779,133	3,116,530	2,337,397	(127,154)	2,210,243	"	86.26%	1,906,556
12	EMS workstations for Banner bank building		231,043	231,043	(3,119)	227,924	"	86.26%	196,607
						-			-
	Production					-			-
	Thermal:					-			-
13	Other Projects (under $500,000) - Bridger	2,135,580	8,542,320	6,406,740	(86,491)	6,320,249	D10	94.97%	6,002,340
14	Other Projects (under $250,000) - Valmy	176,801	707,206	530,404	(7,160)	523,244	"	94.97%	496,925
15	Evaporation Pond Liners	350,000	2,100,000	1,750,000	(23,625)	1,726,375	"	94.97%	1,639,538
						-			-
	Hydro:					-			-
16	Compliance - Upper Pahsimeroi Hatchery Rebuild - 2007 in-service	2,261,660	9,046,640	6,784,980	(91,597)	6,693,383	D10	94.97%	6,356,706
						-			-
	Transmission:					-			-
17	Install a 230/138 kV tie bank		160,759	160,759	(2,170)	158,589	D11	86.26%	136,799
						-			-
	Licenses:					-			-
18	Compliance - Lower Malad Fish Passage	248,063	2,976,750	2,728,688	(36,837)	2,691,850	D10	94.97%	2,556,450
						-			-
	General					-			-
	Land:					-			-
19	Purchase Star property for North River Operations Center	2,777,000	2,777,000	-		-	PTD	92.65%	-
						-			-
	Communication Equipment:					-			-
20	Install Comm equipment and rel		94,850	94,850	(1,280)	93,570	PTD	92.65%	86,692
21	Microwave Improvements for Elk		102,478	102,478	(1,383)	101,095	"	92.65%	93,664
22	Install Microwave Reflector at		228,000	228,000	(3,078)	224,922	"	92.65%	208,390
						-			-
	Other					-			-
23	Distribution & Power Supply	810,098	1,620,196	810,098	(10,936)	799,162	PTD	92.65%	740,424
24	**TOTAL**	16,199,816	69,568,872	53,369,057	(816,082)	52,552,975			45,428,274

Idaho Power Company
Capitalized Pension

Line No.	1 Description	2 IPUC Adjustment	3 Annual Depreciation Reserve Adjustment	4 Net System Correction	5 Allocation Source	6 Allocation % Idaho	7 Idaho Jurisdictional Correction
	Intangible Plant	126,344.00	(8,300.53)	118,043	L96	93.4%	110,200
	Production Plant	2,768,005	(181,852.08)	2,586,153	D10	95.0%	2,456,069
	Transmission Plant	1,054,238	(69,261.21)	984,977	L134	85.3%	840,051
	Distribution Plant	1,905,654	(125,197.44)	1,780,457	L166	93.7%	1,668,179
	General Plant	389,141	(25,565.74)	363,575	PTD	92.7%	336,852
24	**TOTAL**	6,243,382	(410,177)	5,833,205			5,411,351