BEFORE THE

RECEIVED

2007 DEC 10 PM 3:35

IDAHO PUBLIC UTILITIES COMMISSION

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 IN THE STATE OF IDAHO.	)	CASE NO. IPC-E-07-8

DIRECT TESTIMONY OF DONN ENGLISH

IDAHO PUBLIC UTILITIES COMMISSION

DECEMBER 10, 2007

Q. Please state your name and business address for the record.

A. My name is Donn English. My business address is 472 W. Washington, Boise, Idaho 83702.

Q. By whom are you employed and in what capacity?

A. I am employed by the Idaho Public Utilities Commission as a senior auditor in the Utilities Division.

Q. What is your educational and experience background?

A. I graduated from Boise State University in 1998 with a BBA degree in Accounting. Following my graduation I accepted a position as a Trust Accountant with a pension administration, actuarial and consulting firm in Boise. As a Trust Accountant, my primary duties were to audit the day-to-day financial transactions of numerous qualified retirement plans. In 1999 I was promoted to Pension Administrator. As a Pension Administrator, my responsibilities included calculating pension and profit sharing contributions, performing required non-discrimination testing and filing the annual returns (Form 5500 and attachments). In May of 2001, I became a designated member of the American Society of Pension Professionals and Actuaries (ASPPA). I was the first person in Idaho to receive the Qualified 401(k) Administrator certification and I am one of approximately ten people in Idaho who have earned the Qualified Pension Administrator certification. In 2001 I was promoted to a Pension Consultant, a position I held until 2003 when I joined the Commission Staff.

With the American Society of Pension Professionals and Actuaries, I served on the Education and Examination Committee for two years. On this committee I was responsible for writing and reviewing exam questions and study materials for the PA-1 and PA-2 exams (Introduction to Pension Administration Courses), DC-1, DC-2 and DC-3 exams (Administrative Issues of Defined Contribution Plans - Basic Concepts, Compliance Concepts and Advanced Concepts) and the DB exam (Administrative Issues of Defined Benefit Plans). I have also regularly attended conferences and training seminars throughout the country on numerous pension issues.

While with the Commission, I have audited a number of utilities including electric, water and gas companies and provided comments and testimony in several cases that dealt with general rates, accounting issues, pension issues and other regulatory issues. In 2004 I attended the 46th Annual Regulatory Studies Program at the Institute of Public Utilities at Michigan State University sponsored by the National Association of Regulatory Utility Commissioners (NARUC). Since then I have regularly attended NARUC conferences and meetings, primarily the meetings of the Subcommittee of Accounting and Finance.

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

A. The purpose of my testimony in this case is to present the summary exhibit that reflects all the Staff witnesses' recommendations and quantifies Staff's recommended revenue requirement. I will discuss specific adjustments made to Operations and Maintenance (O&M) Expenses and rate base. I also present the exhibit with Staff's recommended capital structure and cost of capital, while discussing the limited risk profile of Idaho Power.

Q. Are you sponsoring any exhibits with your testimony?

A. Yes, I am sponsoring Exhibit Nos. 112-115.

Q. What is Staff's recommended annual revenue requirement for Idaho Power?

A. Staff recommends a revenue requirement of $635,272,968 for the Idaho jurisdiction, which is an increase of $17,452,700 or approximately 2.82% over current revenues. Exhibit No. 112 illustrates the calculation of Staff's revenue requirement on both a system basis and an Idaho jurisdictional basis and compares Staff's revenue requirement to that requested by Idaho Power.

Q. What was the return on equity and overall rate of return used to calculate the revenue requirement?

A. Staff uses a return on equity of 10.25% and an overall rate of return of 7.864%. I will discuss the capital structure, cost of debt and factors that reduce risk for Idaho Power later in my testimony. Staff witness Terri Carlock will justify using a return on equity of 10.25%.

Test Year

Q. What was the test year used to calculate the revenue requirement?

A. Staff audited the 12-month period of July 1, 2006 through June 30, 2007, and used the actual expenses incurred during that test period as a starting point to calculate the appropriate revenue requirement. Staff then made additional adjustments for known and measurable expenses to be incurred after the June 30, 2007 cutoff date. Staff utilized the most recent historic test year to address the Company's concern regarding regulatory lag, while also providing Staff with the opportunity to audit actual expenditures. The June 2007 information became available to Staff at the end of August, allowing Staff enough time to perform an audit and incorporate the results into our prefiled direct testimony.

Q. Idaho Power proposed using a forecasted test year to calculate revenue requirement. Why did Staff produce a different test year?

A. While it would have been much easier to accept the Company's forecasts, Staff believes an historical test year is more appropriate and the Commission has explicitly stated its preference for an historical test year. In Order No. 29838 issued on August 3, 2005, the Commission wrote:

> To facilitate an adequate review, Company data should be provided in time to incorporate the information in the prefiled testimony of Staff and other parties. This will facilitate the hearing and decision processes by having similar time periods and information for Staff and intervenor prefiled testimony, the Company's rebuttal, and at the hearing. ***Using recent, actual data for the hearing will reduce if not eliminate the need to argue over forecasts.*** [Emphasis added]

In Idaho Power's 2003 general rate case, IPC-E-03-13, the Commission also Ordered the use of actual data to replace the forecasts filed in the Company's case. Even as recently as June 19, 2007, the Commission stated in Order No. 30342, "our policy when setting utility rates is to utilize an historic test year that can be verified by audit of actual numbers prior to placing new rates into effect."

The Company's decision to use a forecasted test year and file a general rate case based on budgets created difficulties for Staff in determining the prudency of expenses to be recovered in customer rates. Staff was unable to review any invoices, unable to determine what the Company was going to spend money on, and unable to compare actual expenditures to the forecasts provided by the Company. Idaho Power filed its case and exhibits using FERC account numbers, however the budgets were created at the cost center level and then allocated to the FERC accounts. Because of this allocation, Staff was unable to compare the Company's forecasts to historical levels of expense with any confidence as any deviations could simply be blamed on the allocation method.

Given the need to set rates based on objective and verifiable numbers, along with the Commission's previous orders addressing forecasts, I was charged with the difficult task of reconstructing the Company's case using actual data for a recent 12-month period. During the audit in this case, Staff access to the Company's records and files in a timely manner was limited, making the construction of an historical test year extremely challenging. However, Staff believes the task was necessary to comply with previous Commission Orders and for Staff to present a just, fair and reasonable revenue requirement.

Q. Are there any other problems with forecasted test years?

A. Other than the need to set rates on actual, verifiable numbers, the flaw with the use of a forecasted test year is that it is impossible to know if a forecast is accurate until the forecast period has passed. What is important in establishing accurate rates is the relationship between revenues and costs. As long as a recent and consistent historical test year is used, the revenue/cost relationship will generally be representative of current conditions and the revenue requirement will be accurate for the period when rates are in effect. In the case of Idaho Power, the rates may only be in effect for approximately one year, which eliminates much of the justification for a future test year.

Summary of Adjustments - Rate Base

Q. Please explain Exhibit No. 112.

A. As previously mentioned Exhibit No. 112 illustrates my calculation of the revenue requirement and rate increase and compares Staff's case to the case filed by Idaho Power. Staff's revenue requirement is based on a rate base of $1,807,849,061 and total operating expenses of $669,364,817 for the Idaho jurisdiction.

Q. Please explain Exhibit No. 113.

A. Exhibit No. 113 summarizes the adjustments made to the historical test year to obtain the final numbers included in Staff's revenue requirement. Lines 1-16 outline the proposed rate base on which the Company should earn a return. Column 1 represents Staff's calculated 13-month average rate base. Column 2, line 12 shows the removal of plant held for future use from rate base. Line 13 adjusts working capital for fuel stock and to remove pre-paid assets from rate base and line 15 shows the removal of unused plant at the Bridger Coal Mine pursuant to Commission Order No. 29505. Column 3 illustrates the additional rate base added to the test year for plant that is currently in use but was not online as of June 30, 2007, along with the annualization of certain plant that was placed in service during the year. Staff witness Kathy Stockton is the primary rate base witness and these adjustments are discussed in greater detail in her testimony. Column 4 illustrates the removal of capitalized pension expense from rate base.

Q. Please explain the adjustment for capitalized pension expense.

A. Idaho Power routinely capitalizes a portion of its benefits as overhead. My adjustment removes the capitalized portion of the Company's Net Periodic Pension Cost as calculated under the Statement of Financial Accounting Standards No 87 (FAS 87) for the years 2003-2007. The total amount I remove from rate base is $5,833,205, which is the $6,243,382 that has been capitalized since 2003 net the $410,177 of accumulated depreciation on that amount. I also remove an additional $162,316 from depreciation expense associated with the capitalized FAS 87 pension expense.

Q. Please explain the FAS 87 pension expense.

A. 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.

Q. Has the Commission excluded FAS 87 pension expense from rates?

A. Yes. In the 2003 rate case, Idaho Power proposed to collect millions of dollars in pension expense, claiming increasing pension expense as a driver for the rate increase, although not having invested a single dollar into the pension plan since 1995. In Order No. 29505, the Commission disallowed recovery of FAS 87 pension expense and accepted Staff's adjustment that reconciled the cash contributions from the pension accruals. Ultimately, Idaho Power did not recover any pension expense because it has not been funding the pension plan for several years. In Case No. AVU-E-04-1 and again in Case No. UWI-W-04-4, the Commission used the actual cash contributions required under the Employee Retirement Income Securities Act (ERISA). Because the situation surrounding the pension plan has not changed since the 2003 case, and Idaho Power is not currently contributing to the plan, it is not appropriate for ratepayers to pay a return to Idaho Power for the capitalized portion of this journal entry. This adjustment is consistent with the Commission's Orders on the matter.

Q. Why was capitalized pension expense not mentioned in Order No. 29505?

A. I believe it was the Commission's intent to remove all of FAS 87 pension expense from rates. Staff recommended and the Commission agreed to set the amount of pension expense to be recovered at $0.00, the actual amount funded. After the Commission's Order was issued, the Company notified the Commission that not all of the FAS 87 pension expense was booked into account 926, Employee Pensions and Benefits. Because the entire amount was not booked into that account, Idaho Power could not remove more than that which it had booked. Staff was unaware of the Company's practice of capitalizing a portion of the FAS 87 pension expense and therefore concurred with the Company. The Commission reduced the amount of Staff's adjustment, but ultimately, the amount to be recovered for pension expense was still $0.00.

The additional amount that was not expensed to Account 926 was capitalized, and the Company has been receiving a return from ratepayers on this capitalized amount ever since. The Company has also continued to capitalize a portion of its FAS 87 pension expense every year since the 2003 case. Again, I stress that it is not appropriate for the Company to be receiving a return on this capitalized portion of pension expense when it has not funded the pension plan in over 12 years.

Summary of Adjustments - O&M Expenses

Q. What adjustments were made to the test year O&M expenses?

A. The first adjustments made were the standard Commission adjustments arising from previous orders. These adjustments consist of the removal of FAS 87 pension expense and general advertising expense from rates consistent with prior orders. Also removed from rates is a portion of all social club memberships, contributions and dues along with management expenses that should be allocated to IDACORP. Both Staff and the Company agree with these adjustments, however the amounts may differ due to differences in the test year. The sum total of these adjustments is reflected on Exhibit No. 113, line 20, Column 2.

Staff accepts the Company's adjustment removing memberships, dues, contributions and management expenses as shown in Company witness Lori Smith's Exhibit No. 17 even though the adjustment was based on forecasts. Because the amounts in these adjustments are a cumulative total of small dollar transactions, Staff believes the Company's adjustment is reflective of the level of expenses incurred in any given year. The burdensome nature of combing through small dollar transactions such as these would limit Staff's resources during the audit, and Staff believes it is acceptable to use the Company's adjustments for the purpose of setting rates.

Q. What other adjustments are made to O&M Expense?

A. The next set of adjustments to O&M Expense are the normalizing and annualizing adjustments. Staff witness Rick Sterling discusses the normalizing of power supply expenses and Aurora modeling in his testimony. I have reflected his adjustments in Column 6.

Q. Please discuss the annualizing adjustments.

A. Annualizing adjustments are made to insurance expense and payroll expense. Staff witness Cecily Vaughn's testimony discusses the annualizing of insurance, along with adjustments for FERC administration fees and miscellaneous expenses. I have reflected those adjustments in Column 5 of Exhibit No. 113.

Q. What adjustments are made to payroll expense?

A. The first adjustment I propose is to increase the actual test year operating payroll. Idaho Power hires new employees throughout the year, so I have annualized June's straight-time payroll to capture those new employees and treat them as if they were employed for the entire year. This adjustment provides an additional $3.3 million to Idaho Power to reflect the actual payroll expenses that will be incurred by the Company when rates go into effect. Exhibit No. 114 reflects the calculation of this amount and is similar to Company witness Smith's Exhibit No. 18, page 2. The difference between the two exhibits arises from the starting point of the annualization. Consistent with prior cases, I have used the actual, known amounts of the final month of Staff's test year. Company witness Smith annualizes the forecasted December 2007 straight-time payroll. Based on the Commission's stated preference of using actual data in place of forecasts, it would be inappropriate to annualize a forecasted amount because the opportunity for over statement and over collection is too prevalent.

Q. Do you propose any other increases to the Company's test year payroll?

A. Yes. Pursuant to the stipulation filed in IPC-E-05-8, the Company's last general rate case, I have increased the Company's payroll by approximately $5.7 million for the target level of incentive payments. This calculation is also included on Exhibit No. 114. Section

6(e) of the Stipulation states:

> The Parties agree conceptually that it is reasonable to include an employee pay-at-risk or employee incentive component in test year revenue requirement so long as such incentive component is based on goals that benefit customers and the amounts payable for achieving the goals are limited to reasonable "target" or medium goals. Senior management pay-at-risk is appropriately excluded from the test year revenue requirement.

To abide by the Stipulation Agreement as adopted by the Commission, I have adjusted the Company's payroll upward to reflect these bonuses.

It is worth noting that the target level of incentive payments in the 2005 rate case was 3.5%, while the target level of the bonuses in 2007 is 4%. If the Company intends to continually increase its target levels for incentive payments, then it will become more difficult for Staff to support inclusion of higher amounts in rates.

Q. Do you propose an adjustment to your test year payroll for the Company's annual Salary Structure Adjustment?

A. No I do not for three different reasons. First, the Salary Structure Adjustment (SSA) proposed by the Company is based on increasing the estimated 2008 payroll by an estimated 3%. The Company's proposal violates long-standing ratemaking treatment that post test year adjustments be known and measurable. The amount of the adjustment, if any, is neither known nor measurable, as the Company has in the past foregone any employee raises in times of financial restraint. In Order No. 29505, following the Company's 2003 rate case, the Commission states:

> The Company acknowledged that current financial conditions do, and we believe they ought to, dictate a tightening of the Company's belt so to speak with regard to salaries. Because of this and the fact that the SSA adjustment is neither known nor measurable at this time, the Commission accordingly will remove $2,241,595 from test year expenses for the SSA.

Second, I believe the Commission ought to be cognizant of public perception pertaining to Idaho Power giving employee raises at a time when they are asking to increase the rates it charges for electricity. If Idaho Power believes that today's financial environment mandates the need for increasing rates, it should consider internally cutting costs rather than continually increasing rates. Last, the Company will experience salary savings through attrition. As employees leave the Company, their replacements will presumably be paid less. The Company should use the salary savings from attrition to offer employee salary increases rather than having its customers shoulder the entire burden. For those reasons, I have not increased the test year operating payroll for the SSA.

Q. Are there any other adjustments to O&M Expense?

A. Yes, I have removed approximately $208,000 in legal expenses incurred by Idaho Power from the test year. These expenses are extraordinary and not reflective of the ongoing activities of Idaho Power. My adjustment leaves approximately 98% of all legal fees expensed in the test year. When you also take into consideration all of the legal fees the Company capitalized, the adjustment is a fraction of 1% of all legal fees incurred by the Company.

Q. What types of issues did you consider when you audited the legal fees?

A. I reviewed every invoice for legal services during the test year, and my adjustment will only remove the fees for issues that will likely not occur again in the future. Issues that pertained to things such as water rights, employee personnel matters and workmen's compensation issues were left in the test year because they are reflective of the ongoing level of legal expenses the Company can expect to incur during a given year. I removed $58,057 in legal services pertaining to the merger of PacifiCorp and Mid-American Holding Company. A merger of this magnitude will not likely occur every year, and it would be inappropriate for the Company to recover this amount annually.

I have also removed $55,463 in legal fees related to the delisting of the Idaho Springsnail from the

Endangered Species Act. These expenses may be viewed as political lobbying by Idaho Power, but I have adjusted them because the Idaho Springsnail is now delisted, and the level of legal expenses related to the issue are not reflective of the ongoing legal expenses that Idaho Power is expected to incur.

The final category of legal expenses I have removed from the test year is related to the dissemination of Company hard drives that contained Company proprietary information and confidential employee information. These hard drives were sold to the public on eBay without first being scrubbed to remove data stored on the drives. In Staff's test year, the Company incurred $95,248 in legal expenses pertaining to the dissemination and retrieval of those hard drives. Staff expects that this was a one-time issue.

Q. Has the Commission removed extraordinary legal expenses in past cases?

A. Yes. In Order No. 29602, the Commission found that:

> …removing non-recurring, extraordinary legal expenses to be reasonable and appropriate. Avista contends that some extraordinary expenses always come up and should not be a reason for excluding the level of expense requested. Our view is that the level of legal expenses incurred by the Company is somewhat within its control. **Further, we note that the regulatory accounting system does not permit inclusion of unusual**

> **expenses in a test year for ratemaking purposes.** (Emphasis added).

Also, in Order No. 29505 culminating the Company's 2003 rate case, the Commission accepted Staff's recommendation to remove legal expenses related to potential refunds from the 2000-2001 energy crises and stated:

> We believe the Company acted prudently to ensure that its ratepayers would be able to receive any potential refunds that may have resulted in these cases. That said, there is no reason to believe the entire amount of defending against these cases should be included in the test year as if the same amount will be incurred each year into the future.

In Order No. 29838, the Commission clearly stated "a company is not allowed to include for recovery in rates expenses that are for extraordinary, non-recurring events" as support for removing specific legal fees from United Water's test year. My treatment of the legal expenses in this case is consistent with all prior Commission Orders on the matter.

Capital Structure and Cost of Capital

Q. Please explain the capital structure and cost of capital of Idaho Power.

A. Capital structure refers to the way a corporation is financed by debt, common equity and preferred stock or other forms of securities. The capital structure of Idaho Power consists of approximately 51% debt and 49% common equity. This capital structure is similar to that of PacifiCorp and Avista Utilities, both large electric utilities serving Idaho residents. It is also similar to structures approved in prior Idaho Power general rate cases. For this case, Staff uses the actual capital structure of Idaho Power at June 30, 2007, with some adjustments to be consistent with prior Commission Orders.

The cost of capital for Idaho Power is the weighted sum of the cost of common equity and the cost of debt. Staff uses an overall cost of capital of 7.864% to calculate the Company's revenue requirement. This amount is based on a cost of debt of 5.612%, and a return on equity of 10.25% as mentioned previously. Exhibit No. 115 illustrates the calculation of the capital structure and the overall cost of capital.

Q. Please explain any differences between the capital structure used by Staff and the capital structure proposed by the Company.

A. Staff uses the known capital structure and cost of capital at June 30, 2007, the end of the Staff test year. Using the actual capital structure is consistent with prior Commission Orders, including the last two Idaho Power rates cases heard before the Commission. Idaho Power proposes to use the forecasted capital structure on December 31, 2007.

Q. Please explain the differences in the cost of capital used by Staff and the cost of capital proposed by the Company.

A. The primary difference is in the cost of equity. Idaho Power proposes a cost of equity of 11.5%, while Staff uses a more moderate cost of equity of 10.25%. This is discussed later in my testimony and in Staff witness Terri Carlock's testimony. There is also a difference in the embedded cost of debt proposed by the Company and that used by Staff. Staff uses an embedded cost of debt of 5.612%, which is the actual cost of debt as of June 30, 2007, with pro-formed adjustments for two bond issuances that occurred during 2007. Staff also made adjustments to the variable interest rates on the pollution control revenue bonds to be consistent with Commission Order No. 29505. The Company proposes to use the forecasted cost of debt on December 31, 2007.

Q. Please explain the variable rate bonds you mentioned.

A. The Company currently uses three variable rate pollution control revenue bonds in its long-term debt calculation. These bonds are shown on Company witness Steven Keen's Exhibit No. 11 and discussed in his testimony on page 28. Mr. Keen has calculated a proxy interest rate to use on the variable rate debt by calculating the average spread of the specific debt over the Securities Industry and Financial Markets Municipal Swap Index and applying that spread to the average forecasted index rate for 2007.

Q. Is this consistent with how the interest on variable rate debts has been computed in the past.

A. No. Though the 2005 Idaho Power rate case resulted in a settlement without all issues being presented to the Commission, the interest on the variable rate debt was contested in the Company's 2003 general rate case. In that case, the Company used a 10-year average to compute the interest on variable rate debt. Staff argued that a 10-year average did not reflect the current interest rate environment at the time, resulting in interest rates that were grossly overstated. On rebuttal, Idaho Power stated "the Company could support a five-year average methodology so long as that methodology is applied consistently in future rate cases". The Company also noted in its rebuttal that the Commission accepted a five-year historical average for the Company's auction of its preferred stock in the 1994 general rate case.

On page 36 of Order No. 29505, the Commission found that use of the five-year historical average was the most appropriate measure of the variable rate for the bonds. Consistent with the prior Commission Order, and because of the Company's request in that case for a consistent methodology, Staff uses the five-year daily average of the variable interest rates to compute the cost of debt on the pollution control bonds. The embedded cost of the bonds using the five-year daily average is 3.373% compared to the 3.708% forecasted by the Company.

Q. Are there any other differences in the embedded cost of debt?

A. Yes. At the time the Company filed its case, it was preparing a bond issuance to redeem outstanding commercial paper and to raise funds for ongoing capital expenditures. Company witness Steven Keen's Exhibit No. 11, line 10 indicates a forecasted bond issuance of $153 million at a coupon rate of 5.9%. The actual bond issuance was $140 million at a coupon rate of 6.3%. I have reflected this change on page 2 of Exhibit No. 115, line 10, which illustrates the calculation of the weighted embedded cost of debt.

The Company also issued an additional $100 million in securities backed by First Mortgage Bonds on October 18, 2007, at a coupon rate of 6.25%. The proceeds from the bond sale were to be used to pay off $80 million of 7.38% debt maturing in December of this year. Line 11 on page 2 of my Exhibit No. 115 illustrates the inclusion of this known and measurable post test year financing in the weighted cost of debt.

Q. Please discuss the common equity portion of the cost of capital.

A. The cost of common equity is the return that investors expect to receive. Equity investors expect a return on their capital that is commensurate with the risks they take and consistent with returns that might be available from other similar investments. This profit or return on equity is paid to shareholders as dividends, or retained by the Company to grow the equity investment and future returns. Unlike the cost of debt, the cost of equity is not directly observable in advance and therefore, it must be calculated or inferred from capital market data and trading activity. Staff uses a return on equity of 10.25% to calculate the Company's overall weighted cost of capital.

Q. How did Staff arrive at the 10.25% return on equity?

A. Staff witness Terri Carlock discusses the return on equity in detail in her testimony. My input on the return on equity relates to the risks faced by Idaho Power when compared to the other electric utilities operating in Idaho.

Q. What is the authorized return on equity for other electric utilities operating in Idaho?

A. In Order No. 29602 the Commission authorized a return on common equity for Avista Utilities of 10.4% for Idaho. Avista recently settled a general rate case in Washington and was awarded a 10.2% return on equity in that state. Staff has filed testimony in PacifiCorp's current case (PAC-E-07-5) recommending a 10.25% return. The stipulation signed by all parties to that case adopted the 10.25% return on equity. Idaho Power was also awarded an authorized return on equity of 10.25 percent in its last contested rate case, Case No. IPC-E-03-13. In the 2005 rate case settlement, the return on equity was not explicitly stated, although the overall return on capital was agreed upon in a negotiated settlement of all issues. Given the return on equity granted to other utilities serving Idaho, Idaho Power's proposed ROE of 11.5% is excessive. Staff's recommended 10.25% is in line with other utilities.

Q. The Company maintains that it needs a return on common equity of at least 11.5% given the various risk factors present by the Company. Would you please comment on these assertions?

A. Yes. Risk is the uncertainty or unpredictability of the future results of a company. The greater the range within which future results are likely to fall, the greater the risk associated with an investment in, or extension of credit to the company. Generally speaking, the more risk a company is exposed to, the higher the rate of return that is expected by investors. Idaho Power, as with all regulated utilities, is substantially less risky than its counterparts in non-regulated arenas. In the monopolistic environment in which regulated utilities operate, the uncertainty of demand, financial risks associated with non-payment from customers, and strategic risks associated with competitors are minimal.

Major risks that utilities are exposed to include weather and the regulatory environment in which they operate. An abnormally warm winter can be harmful to a gas utility because customers will not be using as much gas to heat their homes. Abnormally dry winters would be harmful to electric utilities dependent on hydro-generation, like Idaho Power, because less water would be available to generate the electricity needed to meet its demand. Regulatory risk is the risk of being denied recovery of incurred costs.

Risks related to changes in weather have been mitigated by the annual Power Cost Adjustment (PCA), which allows Idaho Power to adjust rates each year to reconcile power supply costs with those costs that are embedded in base rates. On June 1 of this year, Idaho Power was allowed to increase rates 14.5% to mitigate the effects of weather, the continued drought and poor water conditions.

These types of power cost recovery mechanisms are viewed favorably by the financial industries and widely acknowledged to reduce risk faced by utilities.

Q. What areas tend to reduce risk for Idaho Power as compared to Avista and PacifiCorp?

A. Idaho Power's service territory is predominately within the state of Idaho, while both PacifiCorp and Avista provide electric service in multiple states. Both PacifiCorp and Avista have the increased regulatory risk of dealing with multiple state jurisdictions, facing different regulatory treatment, in order to recover incurred expenses.

Idaho Power is also exposed to less regulatory risk because it is the only utility within the state of Idaho with a fixed cost recovery mechanism that reviews the recovery of its fixed costs independent of the volume of kilowatts sold. When rates are based on units sold, as with Avista and PacifiCorp, these utilities can lose revenue if the quantity of kilowatts sold decreases for any variety of reasons. However, Idaho Power's revenue has been decoupled from sales and its rates will be adjusted annually to allow fixed cost recovery. This Fixed Cost Recovery Mechanism removes a substantial amount of risk for Idaho Power and its rate of return should properly reflect the additional revenue stability provided by the Fixed Cost

Recovery Mechanism.

Q. Is there anything else you would like to add before concluding your testimony?

A. Yes. I believe it is important to note that all of Staff's adjustments in this case, including using the 13-month average for rate base, the actual known Operating & Maintenance Expenses, and the removal of non-recurring expenses, are consistent with prior Commission Orders. In this case, Staff has not proposed a single adjustment category that has not been addressed by this Commission previously. Our intent was to maintain as much consistency as possible between rates cases and utilities. This approach should facilitate the entire ratemaking process. When there is consistency between rate cases and utilities, a utility can then file its Application to increase rates with adjustments that will be less contentious. I believe this to be the proper policy and methodology for setting rates.

Q. Does this conclude your direct testimony in this proceeding?

A. Yes, it does.

Idaho Power Company
Summary of Revenue Requirement
IPC-E-07-08

		(1)	(2)	(3)	(4)
		IDAHO POWER		IPUC STAFF	
	RATE BASE	**System**	**Idaho**	**System**	**Idaho**
	Electric Plant in Service:				
1	Intangible Plant	71,402,470	66,657,978	73,296,188	68,442,694
2	Production Plant	1,627,364,155	1,545,527,696	1,611,715,093	1,530,665,590
3	Transmission Plant	673,452,905	574,363,386	636,816,203	542,746,596
4	Distribution Plant	1,129,351,498	1,058,133,361	1,094,704,637	1,025,844,679
5	General Plant	222,710,802	206,339,822	226,194,929	209,687,919
6	Total Electric Plant in Service	3,724,281,830	3,451,022,243	3,642,727,049	3,377,387,478
7	Less: Accumulated Depreciation	(1,545,958,752)	(1,437,090,522)	(1,537,887,342)	(1,429,190,313)
8	Less: Amortization of Other Plant	(39,240,525)	(36,633,103)	(39,701,582)	(37,072,641)
9	Net Electric Plant in Service	2,139,082,553	1,977,298,618	2,065,138,126	1,911,124,524
10	Less: Customer Adv for Construction	(29,852,876)	(29,809,228)	(26,331,284)	(26,292,785)
11	Less: Accum Deferred Income Taxes	(206,314,418)	(191,148,701)	(213,871,282)	(198,263,614)
12	Add: Plant Held for Future Use	738,557	685,078	738,557	684,954
13	Add: Working Capital	55,761,848	51,879,427	53,443,898	49,670,137
14	Add: Conservation - Other Deferred Programs	9,611,655	9,381,070	13,155,568	12,660,688
15	Add: Subsidiary Rate Base	67,989,358	64,384,654	61,527,248	58,265,157
16	**TOTAL COMBINED RATE BASE**	**2,037,016,677**	**1,882,670,920**	**1,953,800,831**	**1,807,849,061**

		IDAHO POWER		IPUC STAFF	
	NET INCOME	**System**	**Idaho**	**System**	**Idaho**
	Operating Revenues:				
17	Sales Revenues	797,776,922	759,542,768	797,398,514	759,206,815
18	Other Operating Revenues	44,635,107	36,668,577	44,701,250	36,730,170
19	Total Operating Revenues	842,412,029	796,211,345	842,099,764	795,936,985
	Operating Expenses:				
21	Operation & Maintenance Expenses	554,783,494	521,551,516	542,571,627	509,075,952
22	Depreciation Expenses	97,955,528	90,930,388	94,176,744	87,473,390
23	Amortization of Limited Term Plant	8,503,692	7,938,646	8,935,263	8,343,592
24	Taxes Other Than Income	20,289,760	18,345,826	20,289,760	18,345,463
	Regulatory Debits/Credits				
25	Provision For Deferred Income Taxes	(10,788,422)	(10,951,869)	(10,788,422)	(10,926,376)
26	Investment Tax Credit Adjustment	1,509,120	1,531,983	1,509,120	1,528,417
27	Federal Income Taxes	46,055,852	46,753,611	51,056,045	51,708,911
28	State Income Taxes	2,806,745	2,849,268	3,767,295	3,815,468
29	Total Operating Expenses	721,115,769	678,949,369	711,517,431	669,364,817
30	Operating Income	121,296,260	117,261,976	130,582,333	126,572,168
31	Add: IERCO Operating Income	5,248,215	4,969,962	5,248,215	4,969,961
32	**Consolidated Operating Income**	**126,544,475**	**122,231,938**	**135,830,548**	**131,542,130**
33	Rate of Return as filed	6.21%	6.49%	6.95%	7.28%
34	Proposed Rate of Return	8.5610%	8.5610%	7.8641%	7.8641%
35	Earnings Deficiency	47,844,523	38,943,519	17,818,303	10,628,928
36	Net-to-Gross Tax Multiplier	1.642	1.642	1.642	1.642
37	**Revenue Deficiency**	**78,560,706**	**63,945,259**	**29,257,654**	**17,452,700**
38	Firm Jurisdictional Revenue	653,153,352	617,820,268	653,153,352	617,820,268
39	**REVENUE REQUIREMENT**	**731,714,058**	**681,765,527**	**682,411,006**	**635,272,968**
40	**Percentage Increase Required**	**12.03%**	**10.35%**	**4.48%**	**2.82%**

Exhibit No. 112
Case No. IPC-E-07-8
D. English, Staff
12/10/07

Idaho Power Company
Summary of Adjustments
IPC-E-07-08

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	RATE BASE	**13-Month Average Beginning Balance**	**Standard Commission Adjustments**	**Kathy Stockton's Adjustments**	**Donn English's Adjustments**	**Cecily Vaughn's Adjustments**	**Rick Sterling's Adjustments**	**Total System**	**Idaho Jurisdiction**
	Electric Plant in Service:								
1	Intangible Plant	72,632,698		789,834	(126,344)			73,296,188	68,442,694
2	Production Plant	1,591,264,629		23,218,469	(2,768,005)			1,611,715,093	1,530,665,590
3	Transmission Plant	606,057,994		31,812,447	(1,054,238)			636,816,203	542,746,596
4	Distribution Plant	1,095,518,113		1,092,178	(1,905,654)			1,094,704,637	1,025,844,679
5	General Plant	223,708,804		2,875,265	(389,141)			226,194,929	209,687,919
6	Total Electric Plant in Service	3,589,182,238		59,788,193	(6,243,382)			3,642,727,049	3,377,387,478
7	Less: Accumulated Depreciation	(1,536,476,148)		1,811,076	(399,882)			(1,537,887,342)	(1,429,190,313)
8	Less: Amortization of Other Plant	(39,555,756)		156,121	(10,295)			(39,701,582)	(37,072,641)
9	Net Electric Plant in Service	2,013,150,334		61,755,390	(6,653,559)			2,065,138,126	1,911,124,524
10	Less: Customer Adv for Construction	(26,331,284)						(26,331,284)	(26,292,785)
11	Less: Accum Deferred Income Taxes	(211,378,607)		2,492,675				(213,871,282)	(198,263,614)
12	Add: Plant Held for Future Use	2,965,125	(2,965,125)	738,557				738,557	684,954
13	Add: Working Capital	65,448,934	(12,005,036)					53,443,898	49,670,137
14	Add: Conservation - Other Deferred Programs	13,155,568						13,155,568	12,660,688
15	Add: Subsidiary Rate Base	61,612,779	(85,531)					61,527,248	58,265,157
16	**TOTAL COMBINED RATE BASE**	**1,918,622,850**						**1,953,800,831**	**1,807,849,061**
	NET INCOME	**Test Year Actuals**							
	Operating Revenues:								
17	Sales Revenues	797,406,535					(8,021)	797,398,514	759,206,815
18	Other Operating Revenues	44,677,792				23,458		44,701,250	36,730,170
19	Total Operating Revenues	842,084,327						842,099,764	795,936,985
	Operating Expenses:								
20	Operation & Maintenance Expenses	558,975,639	(22,234,882)		8,661,379	1,913,235	(4,743,744)	542,571,627	509,075,952
21	Depreciation Expenses	92,719,855		1,619,205	(162,316)			94,176,744	87,473,390
22	Amortization of Limited Term Plant	8,779,142		156,121				8,935,263	8,343,592
23	Taxes Other Than Income	20,289,760						20,289,760	18,345,462
	Regulatory Debits/Credits								
24	Provision For Deferred Income Taxes	(10,788,422)						(10,788,422)	(10,926,376)
25	Investment Tax Credit Adjustment	1,509,120						1,509,120	1,528,417
26	Federal Income Taxes	51,056,045						51,056,045	51,708,911
27	State Income Taxes	3,767,295						3,767,295	3,815,468
28	Total Operating Expenses	726,308,434						711,517,431	669,364,817
29	Operating Income	115,775,893						130,582,333	126,572,168
30	Add: IERCO Operating Income	5,248,215						5,248,215	4,969,962
31	**Consolidated Operating Income**	**121,024,108**						**135,830,548**	**131,542,130**

Exhibit No. 113
Case No. IPC-E-07-8
D. English, Staff
12/10/07

Idaho Power Company
Adjustments to Test Year Payroll

Line No.			(1) Amount
	1) Operating Payroll (Various accts)		
1	ST Payroll 2007 June		$ 14,981,512
2	Annualized (Divided by 2 pay periods, times 26)		129,839,765
3	Less 2007 Total		125,246,935
4	Gross adjustment		4,592,829
5	Add payroll tax @	8.00%	367,426
6	Total adjustment including payroll tax		4,960,255
7	Operating percent		66.29%
8	Adjustment to Operating Expense		$ 3,288,076
	2) Incentive Expense (Various accts)		
9	2007 Straight-time Payroll		$ 129,839,765
10	Plus 2007 Overtime Budget		6,549,699
11	Less: 2007 Officer Payroll		3,187,175
12	Total Payroll Excl Officers		133,202,289
13	Normalized Incentive Rate		4.00%
14	Normalized Incentive		5,328,092
15	Payroll Tax on Normalized Incentive @	8.00%	426,247
16	Normalized Incentive Including Payroll Tax		5,754,339
19	Times incentive operating percent		97.01%
20	Adjustment to Operating Expense for Incentive		$ 5,582,071

IDAHO POWER COMPANY

COMPOSITE COST OF CAPITAL
June 30, 2007 Capitalization

	(1)	(2)	(3)	(4)	(5)
Line No		Capitalization Structure Amount	Percent	Embedded Cost	Weighted Cost
1	Long-term Debt	1,115,460,000	51.437%	5.612%	2.886%
2	Common Equity	1,053,119,486	48.563%	10.250%	4.978%
3	Total Capitalization	$2,168,579,486	100.000%		7.864%

Exhibit No. 115
Case No. IPC-E-07-8
D. English, Staff
12/10/07 Page 1 of 2

IDAHO POWER COMPANY
EFFECTIVE EMBEDDED COST OF
LONG-TERM DEBT
As of June 30, 2007
($000's)

	(1)	(2)	(3)	(4)	(5)	(6)	(7) [Formula]	(8)	(9)	(10) [(4)+(6)-(7)-(8)-(9)]	(11)	(12) [(4) * (11)]	(13) [(12)/(10)]
Line No	Class and Series	Date of Issue	Principal Amount Issued	Principal Amount Outstanding	Price	Premium	Discount	Underwriter Commission	Expense of Issue	Net Proceeds Received	Rate	Annual Interest Requirements	Effective Cost
	First Mortgage Bonds:												
1	7.20 % Series, due 2009	11/23/99	80,000	80,000	100.000	0.0	0.0	500.0	182.8	79,317.2	7.200%	5,760.0	7.262
2	6.60 % Series, due 2011	03/02/01	120,000	120,000	100.000	0.0	0.0	750.0	121.3	119,128.7	6.600%	7,920.0	6.648
3	4.75 % Series, due 2012	11/15/02	100,000	100,000	98.948	0.0	1,052.0	625.0	441.2	97,881.8	4.750%	4,750.0	4.853
4	6.00 % Series, due 2032	11/15/02	100,000	100,000	99.456	0.0	544.0	750.0	441.2	98,264.8	6.000%	6,000.0	6.106
5	4.25 % Series, due 2013	05/13/03	70,000	70,000	99.465	0.0	374.5	437.5	203.7	68,984.3	4.250%	2,975.0	4.313
6	5.5% Series, due 2033	05/13/03	70,000	70,000	99.948	0.0	36.4	525.0	3,810.2	65,628.4	5.500%	3,850.0	5.866
7	5.5% Series, due 2034	03/26/04	50,000	50,000	99.233	0.0	383.5	375.0	149.4	49,092.1	5.500%	2,750.0	5.602
8	5.875% Series, due 2034....	08/16/04	55,000	55,000	98.640	0.0	748.0	412.5	173.3	53,666.2	5.875%	3,231.3	6.021
9	5.30% Series, due 2035....	08/26/05	60,000	60,000	99.319	0.0	408.6	450.0	3,399.7	55,741.7	5.300%	3,180.0	5.705
10	6.30% Series, due 2037....	06/22/07	140,000	140,000	99.801	0.0	278.6	1,050.0	252.7	138,418.7	6.300%	8,820.0	6.372
11	6.25% Series, due 2037...	10/18/07	100,000	100,000	99.732	0.0	268.0	750.0	1,250.0	97,732.0	6.250%	6,250.0	6.395
12	Total First Mortgage Bonds		945,000	945,000			4,093.6	6,625.0	10,425.5	923,855.9		55,486.3	6.006%
	Pollution Control Revenue Bonds:												
13	Sweetwater Series 2006 (Bridger), due 2026 (a)	10/03/06	116,300	116,300	100.000	0.0	0.0	523.4	5,394.0	110,382.6	3.578%	4,161.2	3.770
14	Port of Morrow Series 2000 (Boardman), due 2027..(b)	05/07/00	4,360	4,360	100.000	0.0	0.0	50.0	72.5	4,237.5	2.792%	121.7	2.873
15	Humboldt Series 2003 (Valmy), due 2024 ....(c)	10/22/03	49,800	49,800	100.000	0.0	0.0	252.2	1,451.1	48,096.6	2.420%	1,205.2	2.506
16	Total Pollution Control Revenue Bonds		170,460	170,460		-	0.0	825.6	6,917.6	162,716.8		5,488.1	3.373
17	TOTAL DEBT CAPITAL		$1,115,460	$1,115,460.0			$4,093.6	$7,450.6	$17,343.1	$1,086,572.6		$60,974.4	5.61162%

Exhibit No. 115
Case No. IPC-E-07-8
D. English, Staff
12/10/07

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 10TH DAY OF DECEMBER 2007, SERVED THE FOREGOING **DIRECT TESTIMONY OF DONN ENGLISH,** IN CASE NO. IPC-E-07-8, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

BARTON L KLINE
LISA D NORDSTROM
IDAHO POWER COMPANY
PO BOX 70
BOISE ID 83707-0070
EMAIL: bkline@idahopower.com
lnordstrom@idahopower.com

JOHN R GALE
VP – REGULATORY AFFAIRS
IDAHO POWER COMPANY
PO BOX 70
BOISE ID 83707-0070
EMAIL: rgale@idahopower.com

PETER J RICHARDSON
RICHARDSON & O'LEARY
PO BOX 7218
BOISE ID 83702
EMAIL: peter@richardsonandoleary.com

DR DON READING
6070 HILL ROAD
BOISE ID 83703
EMAIL: dreading@mindspring.com

ERIC L OLSEN
RACINE OLSON NYE BUDGE & BAILEY
PO BOX 1391
POCATELLO ID 83204
EMAIL: elo@racinelaw.net

ANTHONY YANKEL
29814 LAKE ROAD
BAY VILLAGE OH 44140
EMAIL: tony@yankel.net

MICHAEL L KURTZ ESQ
KURT J BOEHM ESQ
BOEHM KURTZ & LOWREY
36 E 7TH ST SUITE 1510
CINCINNATI OH 45202
EMAIL: mkurtz@BKLlawfirm.com
kboehm@BKLlawfirm.com

CONLEY E WARD
MICHAEL C CREAMER
GIVENS PURSLEY LLP
PO BOX 2720
BOISE ID 83701-2720
EMAIL: cew@givenspursley.com

DENNIS E PESEAU PH.D.
UTILITY RESOURCES INC
1500 LIBERTY ST SUITE 250
SALEM OR 97302
EMAIL: dpeseau@excite.com

LOT H COOKE
UNITED STATES DEPARTMENT OF ENERGY
1000 INDEPENDENCE AVE SW
WASHINGTON DC 20585
EMAIL: lot.cooke@hq.doe.gov

DALE SWAN
EXETER ASSOCIATES INC
5565 STERRETT PL SUITE 310
COLUMBIA MD 21044
EMAIL: dswan@exeterassociates.com

(ELECTRONIC COPIES ONLY)
Dennis Goins
E-Mail: dgoinspmg@cox.net

Arthur Perry Bruder
E-Mail: arthur.bruder@hq.doe.gov

Glenda D. Koch
SECRETARY