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 TESTIMONY

OF

STEVEN R. KEEN

Q. Would you state your name, address and present occupation?

A. My name is Steven R. Keen and my business address is 1221 West Idaho Street, Boise, Idaho. I am employed by Idaho Power Company as Vice President and Treasurer.

Q. What is your educational background?

A. I graduated with high honors in 1981 from Idaho State University, Pocatello, Idaho, receiving a Bachelor of Business Administration degree in Accounting. I have also attended numerous seminars and conferences on accounting and finance issues related to the utility industry. I am a Certified Public Accountant licensed in the State of Idaho.

Q. Would you please describe your business experience with Idaho Power Company?

A. I joined Idaho Power Company (Idaho Power or the Company) in September, 1982, in the Property Accounting Department. In March, 1983, I transferred to the Tax Department as a Tax Accountant. From that time through December, 1998, I advanced through every position in the Tax Department including Property Tax Representative, Tax Research Coordinator and finally Corporate Tax Director. In January, 1999 I became President of IDACORP Financial Services. In June of 2006 I accepted the position of Vice

President and Treasurer of Idaho Power Company and IDACORP, Inc.

In the course of my duties with Idaho Power Company, I have presented tax testimony to the Internal Revenue Service. I have also provided tax and/or capitalization rate testimony to the Departments of Revenue and Taxation for Idaho, Oregon, Wyoming and Nevada.

Q. What are your duties as Vice President and Treasurer of Idaho Power as they relate to this proceeding?

A. I oversee the direct financial planning, procurement, and investment of funds for Idaho Power, as well as supervise corporate liquidity management.

My duties and responsibilities include various aspects of all the Company's financings and other financial matters. With respect to long-term financings, sale of bonds and equity, my duties include development of financial plans with senior officers, meeting with representatives of investment banking firms that are interested in underwriting Idaho Power securities, discussions with rating agencies, assisting in preparation of financial material including Registration Statements filed with the Securities and Exchange Commission, representing the Company at information meetings for investment banking firms, reviewing information relative to the Company's financings and recommending disposition of net proceeds. With respect to short-term financings, these duties and responsibilities include negotiation of lines of credit with commercial banks and arranging for the sale of commercial paper.

Q. Do your responsibilities include communication with members of the financial community?

A. Yes. I am in continuous contact with individuals representing investment and commercial banking firms, rating agencies, insurance companies, institutional investment firms, and other organizations interested in publicly traded securities that actively follow IDACORP and Idaho Power Company. In association with the Company's Chief Financial Officer and the Director of Investor Relations, my responsibilities include keeping these persons informed of the Company's financial condition, arranging meetings with these people and Idaho Power's senior executive management, and visiting with financial representatives in their respective offices. Some of these members of the investment community have followed the electric utility industry for an extended period of time and have a great deal of expertise in the financial problems and prospects of utilities.

Through my continual contact with the financial community and review of investment banking analytical reports and articles issued by these firms and the rating agencies, I am able to keep informed on trends, interest rates, financing costs, security ratings, and other financial developments in the public utility industry.

Q. Are you a member of any professional societies or associations?

A. Yes. I am a current member and past board President of the Idaho Society of Certified Public Accountants. I am a current member of and past Council member of the American Institute of Certified Public Accountants. I am a current member and past board Chairman of the Associated Taxpayers of Idaho. I am also a current member of the board of the Idaho Tax Foundation and a member of the Idaho Association for Financial Professionals.

I also receive information from attendance at conferences and seminars of these and other utility professional groups such as the Edison Electric Institute. Through participation in these events, I gain additional insights into the financial developments affecting Idaho Power Company as well as the electric utility industry.

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

A. I am sponsoring testimony as to the point estimate for Idaho Power Company's rate of return on common equity and the embedded cost of long-term debt, risk factors that are unique to Idaho Power Company, the use of a forecasted year-end 2007 capital structure, and the resultant overall cost of capital used to compute the Company's revenue requirement.

Q. What exhibits are you sponsoring?

A. I am sponsoring Exhibits numbered 10 through 15.

Q. What return on equity are you recommending in this proceeding?

A. I have selected 11.5 percent as the minimum reasonable cost of equity for the Company.

Q. Could you briefly outline what conditions require a return on common equity of 11.5 percent?

A. As I will discuss in greater detail later in my testimony, in addition to the reasons advanced by Mr. Avera, I believe that, at a minimum, an 11.5 percent return on equity is required to properly account for the risks confronting Idaho Power Company, namely: (1) a predominately hydroelectric generating base subject to the uncertainties of weather and water; (2) the effects of pricing changes in a volatile wholesale power supply market in the Western United States and specifically the Northwest, coupled with the Idaho Commission Order No. 30215 on the load growth adjustment rate in the Power Cost Adjustment (PCA); (3) the re-emergence of water issues in Idaho, (4) the renewal of federal licenses for the Company's hydroelectric projects, primarily the Hells Canyon Complex which provides 40 percent of the Company's total generating capacity and particularly the significant cost of re-licensing that project; (5) the impact of QF related expenditures, and (6) the inability of the Company to recover the significant capital investment required for present and growing electrical requirements and service reliability for its customers on a timely basis.

Q. Are some of these risk conditions the same risk conditions that have been raised in past Idaho Power rate proceedings?

A. Yes. However, I believe those risk conditions have only grown worse with the passage of time.

Q. Please describe the risks specific to Idaho Power's predominately hydroelectric generating base which is subject to the uncertainties of weather and water.

A. Idaho Power Company and its customers have historically enjoyed the benefits of a hydroelectric-based utility. The availability of hydroelectric power depends on the amount of snow pack in the mountains upstream of Idaho Power's hydroelectric facilities, reservoir storage, springtime snow pack run-off, rainfall and other weather and stream flow management considerations. During low water years, when stream flows into Idaho Power's hydroelectric projects are reduced, Idaho Power's hydroelectric generation is reduced. Extreme temperatures increase demand for power by customers who use electricity for cooling and heating, and moderate temperatures decrease demand for power. Precipitation or the lack thereof also directly affects the Company's irrigation load. Weather and hydro-production are inextricably linked. Reduced hydroelectric generation resulting from below normal water flows requires the Company to use more expensive thermal generation and/or purchased power to meet the electrical needs of its customers.

Q. Does the Company's PCA remove this risk?

A. Not entirely. Although the Idaho Commission grants recovery for the majority of the variations in power supply expense through the Company's PCA, the recovery is less than 100 percent. Although originally viewed by the Company as an earnings stability mechanism, the PCA has provided less stability than anticipated. The risks associated with the Idaho jurisdictional 10 percent of variations in power supply expenses (the portion the Company's shareholders are required to absorb) are having an increasingly significant adverse financial impact on the earnings capability of the Company. Actual results no longer provide the level of earnings stability originally contemplated by the Company.

Q. Why have the earnings stability benefits of the PCA to the Company declined?

A. While I do not profess to be an expert on the details of the PCA mechanism, from a financial perspective a significant factor affecting the PCA has changed.

Q. Please elaborate.

A. The Commission in 1993 authorized a PCA mechanism with the principal parts being fuel expenses, a deduction for surplus sales, purchased power expenses and an adjustment to compensate for the difference between actual load and the load used to establish base rates.

At the time the PCA was established in 1993 there was a fundamental relationship between FERC jurisdictional rates for purchases and sales and Idaho Power retail rates. All of the prices or rates were cost-based.

In 1997, FERC determined that it would permit market-based rates as opposed to cost-based rates. While Idaho retail rates remained cost based, FERC jurisdictional rates for sales and purchases became market based. The cost or price for both FERC jurisdictional power purchases and sales attributable to Idaho Power increased significantly. This created an enormous difference between the monetary amounts for purchased power and surplus sales that the parties considered in 1992 and 1993 when the PCA methodology was established, and the costs and prices experienced in recent years. This volumetric change is truly monumental when you consider the financial size of Idaho Power. Mr. Said informed me that average Idaho Power purchases for the period 1993 though 1996 were at an average expense of $22,389,000 per year. For the period 1997 through 2006 the average Idaho Power purchases were at an average expense of $214,840,000. Likewise, surplus sales for the period 1993 through 1996 were at an average revenue of $42,000,000. For the period 1997 through 2006, the average sales were at an average revenue of $190,592,000.

Q. Did you ask Mr. Said to provide you with information as to the decline in PCA earnings stability benefits since the inception of the PCA due to increased prices?

A. Yes. Mr. Said has informed me that at the time of the inception of the PCA, the Company, interested parties and the Commission envisioned power supply expenses would vary $120 million from a high-water scenario to a low-water scenario. With base rates set at the mean of the range and 90 percent sharing by customers, the Company's exposure to adverse water power supply expenses was $6 million (1/2 * $120 million * 10 percent = $6 million).

In Mr. Said's testimony in this case, he states that the range of power supply expenses from a high-water scenario to a low-water scenario is now $330 million. Using a similar computation, the Company's exposure to adverse water is now $16.5 million (1/2 * $330 million * 10 percent). The risk exposure today is 2.75 times as great as it was at the time the PCA was adopted. This increased amount that is at risk should be recognized in the Company's return on equity in light of FERC market-based rates and how those purchase power costs are calculated and treated in the Idaho PCA mechanism.

Q. Does your recommended 11.5 percent return on equity reflect this increased risk to the Company based upon the expanding range of power supply expense possibilities?

A. I allowed for a modest upward adjustment to reflect the increased volatility in the markets. If market changes limit the upside opportunity from the PCA mechanism, then an additional return on equity would be required. In essence, if the predominant outcome of the PCA is now for the shareowner to absorb some portion of additional costs, my recommended return on equity is too low.

Q. On January 9, 2007, the Commission issued Order No. 30215 concerning the load growth adjustment rate in the PCA mechanism. Are you aware of that order?

A. Yes.

Q. How was that Order received by the financial community?

A. It heightened their concern that the Company will be unable to earn its allowed rate of return. A. G. Edwards & Sons, Inc. issued a research report on February 16, 2007 stating, "The revised LGAR mechanism and use of the historical test years in rate cases makes it difficult for IDA to earn its allowed ROE in periods of strong customer and rate base growth." A similar report from Wachovia Capital Markets, LLC on February 15, 2007 states, "With the resulting regulatory lag and reduced prospects for Idaho Power to recover its authorized return on equity, in our view, the decision reduces confidence in the regulatory backdrop, especially as the Company begins to enter a new baseload build cycle. Moreover, more frequent rate case filings equate to more cost, more time, and more uncertainty."

Q. In that Order, did the Commission discuss the relationship between the load growth adjustment and the return on equity?

A. Yes. In that Order the Commission stated: "[B]ecause this process (the adjustment of load growth recovery) puts the Company at some business and financial risk, it is awarded a commensurate equity return." (Order No. 30215 at p. 10).

Q. What does the Commission's statement mean to you?

A. It communicates to me that the additional risks borne by the Company due to the denial of load growth costs are to be offset by a commensurate equity return. As the load growth adjustment rate increases, the return on equity component must also increase.

Q. Did you request from Mr. Said, as a result of Order No. 30215, a quantification of the cost attributable to the increase in the PCA load growth adjustment from $16.84 per MWh?

A. Yes. I asked Mr. Said to provide me with the reduced expense recovery due to the removal of additional load growth-related power costs from the PCA if the load growth adjustment rate was increased from $16.84 per MWh.

Mr. Said provided me with three calculations. One calculation indicated that a change from $16.84 MWh to $29.41 MWh, as adjusted when Order No. 30215 was issued, would remove an additional $3.4 million of expense and require a 21 basis point increase to my ROE recommendation. He also provided the calculations for the required change based on his proposed rate of $29.16 MWh and the results were nearly identical with approximately $3.4 million removed from expense and a required 21 basis points correlative adjustment to ROE.

A final calculation was included using a rate of $71.58 MWh which Mr. Said evidently obtained from a literal interpretation of the provisions of the load growth calculation contained in Order No. 30215. This adjustment removes an additional $15 million of revenue requirement and would require a correlative increase to ROE of 91 basis points.

Q. Does your rate of return recommendation reflect the calculations for the load growth adjustment Mr. Said provided you?

A. My rate of return would not require modification if the change approximates Mr. Said's $29.16 per MWh load growth adjustment proposal. My recommended rate of return of common equity 11.5 percent has increased from the Company's prior rate of return and the changes to load growth-related power costs contributed to that increase. If the load growth adjustment rate is increased above $29.16 per MWh, the return on common equity must increase. For instance, if further reduced cost recovery attributable to the load growth adjustment is $15 million (using a load growth adjustment rate of 71.58 MWh), my rate of return recommendation would need to be increased to 12.2 percent which would be an increase of 70 basis points.

Q. Are there any other water or weather-related risks of the Company that you would like to comment on?

A. Yes. Comments from rating agencies and analysts have expressed concern about the potential impacts from aquifer recharge and water rights in general. While it is difficult to quantify potential exposures, the heightened level of discussions and disagreements on these issues have increased the Company's risk profile in the financial community.

Q. Please describe the risks regarding the renewal of federal licenses for the Company's hydroelectric projects.

A. Idaho Power Company is the only investor-owned electric utility in the United States with 55 percent of its generation derived from hydro generating facilities under normal water conditions. With such a large portion of the Company's generation resources based on hydro facilities, a negative economic impact resulting from renewing the federal licenses of these facilities could have a significant financial impact on the Company and the prices its consumers pay for electricity. As part of this process, the Company has filed and will continue to file applications with the FERC for new licenses for its hydro generating capacity.

Q. What are the associated financial risks to the Company from re-licensing its hydro generating capacity?

A. Once an application is filed, the time frame to actually receive an order from the FERC is unknown. This uncertainty combined with the potential loss of generation capability due to operational changes, and the magnitude of the financial impact of unknown Protection, Mitigation, and Enhancement (PM&E) costs are financial risks to the Company.

Q. Are there other hydro re-licensing-based financial risks considered by the investment community?

A. Yes. For any particular generating facility, the worst possible outcome would be the loss of the license to a competing party. Along with the uncertainty as to the eventual receipt of licenses and the costs involved in preparing for the license applications, costs of PM&E related to these projects are also difficult to quantify. The potential financial magnitude of these PM&E and their effect on the Company's low-cost hydrogeneration resources threaten the financial stability of a company the size of Idaho Power and the ultimate rates it must charge its customers. These amounts will vary between each facility, but in all cases they can be significant due to lost generation capacity, generation at a higher cost, and the decreased ability of the Company to time and control water releases.

If the Company cannot generate when it is most advantageous for the system, then some of the economic value of the generation has been lost, even if the amount of total generation does not change. In addition to the hydro re-licensing risk, the Company continually faces significant capital, operating and other costs relating to compliance with current environmental statutes, rules and regulations. These costs may be even higher in the future as a result of, among other factors, changes in legislation and enforcement policies and the potential additional requirements imposed in connection with the re-licensing of the Company's hydroelectric projects.

Q. Please address the risk associated with the Company's re-licensing effort before the FERC for the Hells Canyon generating facilities.

A. The Hells Canyon generating facilities comprised of Hells Canyon, Oxbow, and Brownlee dams make up 67 percent of the Company's hydro generation capacity and 40 percent of its total generation capacity. The Hells Canyon license application was filed in July, 2003, and accepted by the FERC for filing in December, 2003. The FERC process moves at a slow and deliberate pace due to the large number of interested parties involved in evaluating the application, thus the timing of the issuance of a new Hells Canyon facilities license remains uncertain.
Historically, FERC has given the Company an annual license renewal (under the existing old license) until the formal new license is issued. It is difficult to predict the ultimate financial impact of the re-license until the new FERC license is issued and all of the re-license conditions are known.

Q. Please comment on the re-licensing efforts that the Company has already undertaken.

A. As part of the FERC re-licensing regulations and pursuant to the Federal Power Act, the Company is required to conduct numerous studies and evaluations concerning botanical issues, land management issues, hydraulic issues, flow modeling issues, sedimentary issues, water quality issues, aquatic issues, recreation issues, cultural resource issues and fish and wildlife issues.

Q. How does the Company account for the cost of these projects?

A. As provided by FERC and state accounting requirements, the project costs are booked to Construction Work in Progress (CWIP) since they are part of the re-licensing process. While the costs are included in CWIP, the Company accrues a capitalization charge commonly referred to as an allowance for funds used during construction (AFUDC). When the new license is issued, those costs will be transferred to electric plant in service and AFUDC will cease.

Q. Does the Company combine the FERC re-licensing projects for accounting purposes?

A. Periodically the costs of re-licensing projects are transferred from individual projects to a rollup project for the particular FERC license.

Q. Just addressing the FERC rollup projects for Brownlee, Oregon and Hells Canyon, for purposes of illustration, what were the rollup amounts as of December

31, 2006?

A. As of that date, the rollup costs for the Hells Canyon re-licensing were:

Brownlee	$34,742,257
Hells Canyon	$23,814,989
Oxbow	$10,907,067

Q. Again, for purposes of illustration, for the year 2006 what was the total amount of AFUDC attributable to the Hells Canyon re-license?

A. Including not only rollup but all Hells Canyon projects, the total amount of AFUDC was $4,776,138.

Q. Is this amount included in the Company's earnings?

A. Yes. AFUDC is a non-cash item that represents the cost of financing construction projects with borrowed funds and equity funds. The component for AFUDC attributable to borrowed funds is included as a reduction to interest expense, while the equity component is included in other income. The total amount of AFUDC is charged to CWIP.

Q. Will the amounts be larger at the end of calendar year 2007?

A. Yes, CWIP for the Hells Canyon Project re-licensing which includes AFUDC of 4,858,000 for the year 2007 is forecasted to be $97,544,000.

Q. What will occur when the Company receives a new license for the Hells Canyon facilities?

A. The amounts in CWIP will be transferred to plant in service and the accumulation of AFUDC will cease. The result will be a large increase in rate base with earnings of the Company declining since there will be no AFUDC. Because this is a re-license of an existing hydro facility, there will be no increase (if not a decrease due to operational changes) in the generation of power and thus no increase in sales revenues. The financial industry sees this as a risk that confronts the Company which can be summarized as follows: upon receipt of a re-license, (1) the Company's earning will go down (no AFUDC), (2) the Company's rate base will go up (transfer from CWIP), and (3) no additional sales revenues (same plant but new license).

Q. Does the regulatory treatment of energy purchases the Company makes from PURPA Qualifying Facilities (QFs) increase the financial risk to Idaho Power?

A. Yes, the regulatory treatment of QF expenditures provides for a one-for-one recovery of dollars expended, but does not provide for a return to compensate the Company for this activity. The Company is, in effect, buying and selling energy pursuant to a legal mandate, without any compensation for providing this service. Simplistically, this regulatory treatment is similar to requiring a person operating a business to buy a product at the same price it must be sold. The mere dollar-for-dollar recovery of QF expenditures, but no return for the use of the Company's balance sheet and liquidity in managing QF programs, is viewed as a significant risk by the rating agencies. They are not making a judgment related to the appropriateness of QF energy purchase programs, but merely pointing out the cost of the financial risk(s) arising from a QF transaction, and that this risk should be reflected in a higher return on equity to credit the Company for its QF contracts.

Q. Has the Commission previously considered a proposal to compensate the Company for its management of QF programs?

A. Yes. In determining the appropriate rates to be paid for power and energy sold to Idaho Power pursuant to section 210 of the PURPA Act of 1978, the Commission through Order 18190 at page 21 indicated:

> In another context, Staff witness Drummond proposed that Idaho Power be given a management fee amounting to five percent of the gross payments made to CSPP's [QFs]. The Commission will do all in its power to encourage Idaho Power to manage such projects in an orderly fashion. Orderly management includes adequate staffing and clear lines of authority among personnel assigned to deal with CSPPs; good faith negotiating of contracts and expeditious processing of worthy applications; and, above all, a showing that the Company has integrated cogeneration and small power resources into its own planning,

> construction and financing programs. When orderly management is demonstrated, the Commission will reconsider the question of an appropriate management fee or an equity adjustment.

The current expected normalized cost for QF purchases is approximately $93 million. A five percent management fee on these normalized QF costs would result in a payment to the Company of approximately $4.65 million. Using the same methodology as provided to me by Mr. Said relating to changes in the load growth adjustment, this $4.65 million increase would correlate to an additional 28 basis points of ROE that would increase my recommended ROE to 11.78 percent.

Q. Do the rating agencies recognize the financial costs of QF-related transactions?

A. Yes. Like other electric utilities, when the Company adds to its rate base, it must use some portion of shareholder equity to fund the investment. The Company must maintain its equity component above a certain level as it continues this investment process. If it does not, the debt level increases and the Company will face the threat of a bond rating downgrade. Conversely, when the Company enters into a QF contract for purchased power, an obligation not reflected in its financial statements, an increase in equity is needed to maintain credit quality. Unless an equity component is provided to offset the debt-like obligation of long-term QF purchase power contracts, the Company faces off-balance sheet financial risk. For financial commitments that do not appear on the balance sheet, credit rating analysts impute the debt and interest equivalents on the financial statements of the Company to achieve a more accurate picture of the risk associated with their investment. The added equity needed to offset this imputed debt and interest represents the effect that long-term purchased power commitments have on the cost of capital. Any increase in the long-term obligation of a utility related to its capacity and energy resources will have to be backed by an appropriate amount of equity in the eyes of the investment community.

In reviewing its evaluation of the credit implications of QF-related expenditures, S&P in May of 2003, noted that such agreements are "debt-like in nature" and that the increased financial risk must be considered in evaluating a utility's credit risks.

> Standard & Poor's Ratings Services views electric utility purchased-power agreements (PPA) as debt-like in nature, and has historically capitalized these obligations on a sliding scale known as a "risk spectrum." Standard & Poor's applies a 0% to 100% "risk factor" to the net present value (NPV)of the PPA capacity payments, and designates this amount as the debt equivalent.
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> Standard & Poor's evaluates the benefits

> and risks of purchased power by adjusting a purchasing utility's reported financial statements to allow for more meaningful comparisons with utilities that build generation. Utilities that build typically finance construction with a mix of debt and equity. A utility that leases a power plant has entered into a debt transaction for that facility; a capital lease appears on the utility's balance sheet as debt. A PPA is a similar fixed commitment. When a utility enters into a long-term PPA with a fixed-cost component, it takes on financial risk. Furthermore, utilities are typically not financially compensated for the risks they assume in purchasing power, as purchased power is usually recovered dollar-for-dollar as an operating expense.

Q. Please describe the risks relative to the Company's ability to recover significant capital investment required for present and growing electrical requirements.

A. As the Company's generation and transmission systems age and customer electrical requirements increase, additional investment is required to meet reliability standards and the additional demand on its electrical infrastructure. The Company's latest forecast requires construction budgets of approximately $266 million in 2008 and $815 million for 2008 through 2010 combined. Construction investments of this magnitude introduce two elements of risk: first, the ability of the Company to attract the required capital and, secondly, the recovery of these investments is on a deferred basis and subject to the regulatory process.

Q. Has the Company been able to earn its authorized return on equity during recent years?

A. No. In fact, the Company's actual return on equity has been less than 9 percent for the last four years.

Q. What has prevented the Company from earning its authorized or allowed return on equity?

A. I have previously addressed in my testimony several issues which I believe adversely impact the Company's ability to earn its authorized return. However, in my opinion, it is the use of a historical test year that is the primary reason the Company fails to earn its authorized or allowed return on equity at this time. I believe this opinion is universally held by financial analysts that follow Idaho Power/IDACORP. Idaho Power Company is in a consistent position of always recovering its costs on a historical basis when its costs are constantly increasing on a prospective basis. As a result, there is a consistent recovery lag. As long as Idaho Power is obligated to continue a large construction program to accommodate growth and increased consumer demand, it can never "catch-up".

Q. What effect does growth have on the use of historical data?

A. Growth inherently worsens the effects.

Operation & Maintenance (O&M) expenses typically rise faster than inflation as new facilities and personnel are added to meet growing customer demands. Yet recovery is based on lower historical amounts from a prior period. Likewise, the allowed rate of return is applied to a rate base from a prior historical period and new plant additions suffer some period of zero percent return awaiting eventual rate base treatment.

Q. What is the status of Idaho Power Company's credit ratings?

A. Idaho Power Company's credit ratings as of June 1, 2007 are as follows:

	S&P	**Moody's**	**Fitch**
Corporate Credit Rating	BBB+	Baa 1	None
Senior Secured Debt	A-	A3	A-
Senior Unsecured Debt	BBB (prelim)	Baa 1	BBB+
Short-Term Tax-Exempt Debt	BBB/A-2	Baa 1/VMIG-2	None
Commercial Paper	A-2	P-2	F-2
Credit Facility	None	Baa 1	None
Rating Outlook	Negative	Stable	Stable

Q. Standard & Poor's has continued to place the Company on a "negative outlook". What prompted this action?

A. Per the Standard & Poor's May 11, 2007 Research Update, their Credit Analyst gave the following reason:

> The negative outlook reflects the potential for weakened financial metrics in accordance with expected large capital expenditures and increase[d]

> generation cost. Also the uncertainty of the effect of the recharge programs under the stipulation agreement and uncertainty regarding the IRS's assessment of a $45 million tax liability are factors.
>
> A downward rating action could occur if IPC is unable to achieve its projected financial metrics. Conversely, an outlook or a rating improvement will depend on the restoration of adequate financial performance, with modest reliance on power cost deferrals, and minimal or no ultimate financial consequences from the aquifer recharge program.

Q. Do you believe that the current credit ratings of Idaho Power Company are adequate?

A. Other utilities with the same credit ratings as Idaho Power Company are able to raise capital in today's markets. However, these new debt/bond issues are at a higher cost than if these utilities had a higher credit rating (the higher the credit rating, the lower the cost). This results in passing on higher interest costs to the customer over the life of the bonds.

The biggest threat to Idaho Power Company's current ratings is unforeseen risk. Should an unforeseen event cause Idaho Power Company's short-term credit ratings to be lowered, Idaho Power Company would no longer be able to issue commercial paper. This would cause Idaho Power Company to draw on the more expensive credit lines, resulting in passing on higher interest costs to the customer.

Q. Would you please describe Exhibit No. 10?

A. Exhibit No. 10 details the calculation of the Idaho Power Company capital structure for long-term debt, and the common equity balance resulting from the Company's forecasted year-end 2007 capital structure as provided to me by Ms. Lori Smith, and the resulting overall rate of return that I am recommending.

Q. The capital structure presented on Exhibit No. 10 incorporates changes to the Company's financial reporting of its capital structure. Could you please discuss the rationale for the variance?

A. For financial reporting purposes, the American Falls Bond Guarantee and the Milner Dam Note Guarantee are included in the long-term debt portion of the capital structure. For ratemaking purposes, the interest costs associated with both the American Falls and the Milner debt securities are covered as O&M expenses. Even with these exclusions, the capital structure presented in my Exhibit No. 10 is reasonable in light of industry and rating agency criteria.

Q. Would you please comment on Exhibit No. 11?

A. Exhibit No. 11 details the calculation of the cost of debt used in the estimated year-end 2007 capital structure. The cost of debt is 5.591 percent. Please note that two forecasted bond issuances of $153 million and $80 million respectively appear on lines 10 and 11 respectively. The $153 million issue will be used to redeem outstanding short term Commercial Paper as well as financing ongoing capital expenditures. The $80 million issue will be used to retire the 7.38 percent First Mortgage Bonds and is forecasted to have a coupon of 6.20 percent. The interest rates for these issuances were derived with the following methodology. First, the Company assumed a maturity on the bonds for 30 years. Second, Idaho Power's current credit spread on 30-year issues is 110 bps (basis points). Third, the Company contacted Bank of America to obtain the indicative forward Treasury rates as of July 2, 2007 and December 3, 2007. The Indicative Forward Treasury Rate plus Idaho Power's credit spread equals the forecasted interest rate. Exhibit 11, notes (e) and (d) show this calculation.

Q. Does the Company utilize variable rate securities in its long-term capitalization?

A. Yes. The Company currently utilizes several variable rate securities in its long-term capitalization. These securities are the County of Sweetwater [Bridger] Pollution Control Revenue Bonds Variable Rate Series 2006 ($116.3 million), the Port of Morrow [Boardman] Pollution Control Revenue Bonds Variable Rate Series 2000($4.36 million), and the Humboldt County [Valmy] Pollution Control

Revenue Bonds Variable Rate Series 2003 ($49.8 million). These securities are listed on lines 13, 14, 15, and 16 on Exhibit No. 11.

Q. Would you please describe the variable rate nature of these pollution control bonds?

A. These variable rate pollution control bonds, although considered long-term securities, have features that allow the Company to take advantage of rates applicable to short-term securities. The County of Sweetwater Pollution Control Variable Rate Bonds Series 2006 (Bridger Variable Rate Bonds) and the Port of Morrow Pollution Control Variable Rate Bonds Series 2000 (Boardman Variable Rate Bonds) reset their interest rate on a weekly basis. The Humboldt Pollution Control Variable Rate Bonds Series 2003 (Valmy Variable Rate Bonds) reset their interest rate every 35 days.

The Bridger Variable Rate Bonds reset their interest rate every 7 days via a Dutch auction process (lowest bid received by an Auction Agent that covers the bonds outstanding) to reflect the current market conditions. On a weekly basis, the Boardman Variable Rate Bond's weekly interest rate is determined the first day of a weekly period by a Remarketing Agent. The Remarketing Agent examines tax-exempt obligations comparable to the Boardman Variable Bonds known to have been priced or traded under the thenprevailing market conditions and finds the lowest rate which would enable sale of the Boardman Variable Rate Bonds. The Valmy Variable Rate Bonds reset their interest rate every 35 days via a Dutch auction process (lowest bid received by an Auction Agent that covers the bonds outstanding) to reflect the current market conditions.

Q. Please comment on the derivation of the effective cost of the interest rates for the Pollution Control Bonds listed on lines 13, 14, 15, and 16 of Exhibit No. 12.

A. Exhibit No. 12 is a chart that depicts the Securities Industry and Financial Markets Municipal Swap Index (SIFMA Index) [formerly The Bond Market Association (BMA) Swap Index] for the last five years dating from March 7, 2007. The SIFMA Index, produced by Municipal Market Data (MMD), is a 7-day high-grade market index comprised of tax-exempt Variable Rate Demand Obligations (VRDO's) from MMD's extensive database. The Index was created in response to industry participants' demand for a short-term index to accurately reflect activity in the VRDO market.

Q. Please describe Exhibit 13.

A. Exhibit No. 13 shows the Company's average spreads (difference of the Company's actual variable rate, plus or minus, when compared to the SIFMA Index during the same time period) over the SIFMA Index for the Bridger

Variable Rate Bonds, the Boardman Variable Rate Bonds, and the Valmy Variable Rate Bonds over the last five years. Please note that the Valmy and Bridger Variable Rate Bonds do not have five years of data since each were issued in October, 2003 and October, 2006, respectively.

In light of the historic lows of short-term interest rates during the last five years, it was determined that the methodology used in the last rate case (Order No. 29505) utilizing the average of the last five years of the SIFMA Index, plus an average of the Company's spreads over that same five-year period of these variable rate bonds, would produce an erroneous implicit coupon rate for variable rate debt. Simply put, this method would produce an implicit coupon rate well below current market rates and an unreasonable result. Therefore, the Company used a forward market based approach. This methodology will produce a forecasted implicit coupon rate for variable rate debt that more accurately reflects near-term market conditions.

Q. Please describe Exhibit 14.

A. Currently, there is no forward market curve directly applicable to variable rate bonds. However, Bank of America (BofA) Investments has developed an intrinsic forward curve for the SIFMA Index. Exhibit No. 14 is a graph of this curve.

An analysis is performed to calculate each variable rate bond's historic spread over/under the SIFMA Index. An average of BofA's intrinsic forward curve for 2007 is also calculated. This average plus each variable rate bond's historic spread over/under the SIFMA Index serves as the basis for calculating the forecasted 2007 implicit coupon rate for Idaho Power's variable rate debt.

Q. Please describe Exhibit 15.

A. The average of BofA's intrinsic forward curve for 2007 is 3.58 percent, the average five-year Company spreads for the Bridger Variable Rate Bond Series 2006 is -0.07 percent, the Boardman Variable Rate Bond is 0.71 percent, and the Valmy Variable Rate Bonds is -0.07 percent. These calculations are summarized in Exhibit No. 15 and are also presented in Exhibit 11, column (11), line nos. (13)-(15).

The Effective Cost in Exhibit 11, column (13) is calculated by taking Net Proceeds Received column (10) divided by Annual Interest Requirements column (12) times 100.

Q. What is the overall cost of capital for Idaho Power Company?

A. As shown on Exhibit 10, using the forecasted year-end 2007 capital structure provided to me by Ms. Smith, the cost of capital presented in my testimony, and incorporating the 11.5 percent cost of equity, the resultant overall cost of capital for Idaho Power Company is 8.561 percent.

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

A. Yes, it does.

IDAHO POWER COMPANY

COMPOSITE COST OF CAPITAL
AT ALLOWED RATE OF RETURN - SUMMARIZED
Forecasted December 31, 2007 Capitalization

	(1)	(2)	(3)	(4)	(5)
Line No		Capitalization Structure Amount	Percent	Embedded Cost	Weighted Cost
1	Long-term Debt	1,108,460,000	49.737%	5.591%	2.781%
2	Common Equity	1,120,188,586	50.263%	11.500% *	5.780%
3	Total Capitalization	$2,228,648,586	100.000%		8.561%

Note:
* Requested rate of return 2007 Idaho PUC rate case.

IDAHO POWER COMPANY
EFFECTIVE EMBEDDED COST OF
LONG-TERM DEBT
At Forecasted Rates at 12/31/2007
($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	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	Forecasted 5.90% Series, due 2037..(e)	07/02/07	153,000	153,000	100.000	0.0	0.0	1,147.5	400.0	151,452.5	5.900%	9,027.0	5.960
11	Forecasted 6.20 % Series, due 2037..(d)	12/03/07	80,000	80,000	100.000	0.0	0.0	600.0	400.0	79,000.0	6.200%	4,960.0	6.278
12	Total First Mortgage Bonds		938,000	938,000			3,547.0	6,572.5	9,722.8	918,157.7		54,403.3	5.925%
	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	3.520%	4,093.8	3.709
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	4.290%	187.0	4.414
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	3.520%	1,753.0	3.645
16	Total Pollution Control Revenue Bonds		170,460	170,460		-	0.0	825.6	6,917.6	162,716.8		6,033.8	3.708
17	TOTAL DEBT CAPITAL		$1,108,460	$1,108,460.0			$3,547.0	$7,398.1	$16,640.4	$1,080,874.4		$60,437.0	5.591%

(a) - Interest rate for Sweetwater Series 2006 Bond was established by taking the average spread over the SIFMA index during the life of the bond plus the forecasted SIFMA forward rate for 2007 (-0.07 + 3.58 = 3.52)
(b) - Interest rate for Port of Morrow Series 2000 Bond was established by taking the average spread over the SIFMA index during the last 5 years plus the forecasted SIFMA forward rate for 2007 (0.71 + 3.58 = 4.29)
(c) - Interest rate for Humboldt Bond was established by taking the average spread over the SIFMA index during the last 3 years plus the forecasted SIFMA forward rate for 2007 (-0.07 + 3.58 = 3.52)
(d) -This issuance will replace the retired 7.38% First Mortgage Bond. The new issue will assume a 30 year maturity.
Forecasted interest rate is calculated as follows: T + 110 bps; forecasted Treasury of 5.10% = yield of 6.20%
(e) - This issuance will be used to redeem outstanding S-T Commercial Paper as well as financing ongoing capital expenditures. The new issue will assume a 30 year maturity.
Forecasted interest rate is calculated as follows: T + 110 bps; forecasted Treasury of 4.80% = yield of 5.90%
NOTE: American Falls Dam Bond and Milner Dam Note are guarantees. These instruments are excluded in rate making calculations and therefore are omitted from this schedule.

Securities Industry And Financial Markets Municipal Swap Index (SIFMA Index)

Last Five Years from 3/7/2007

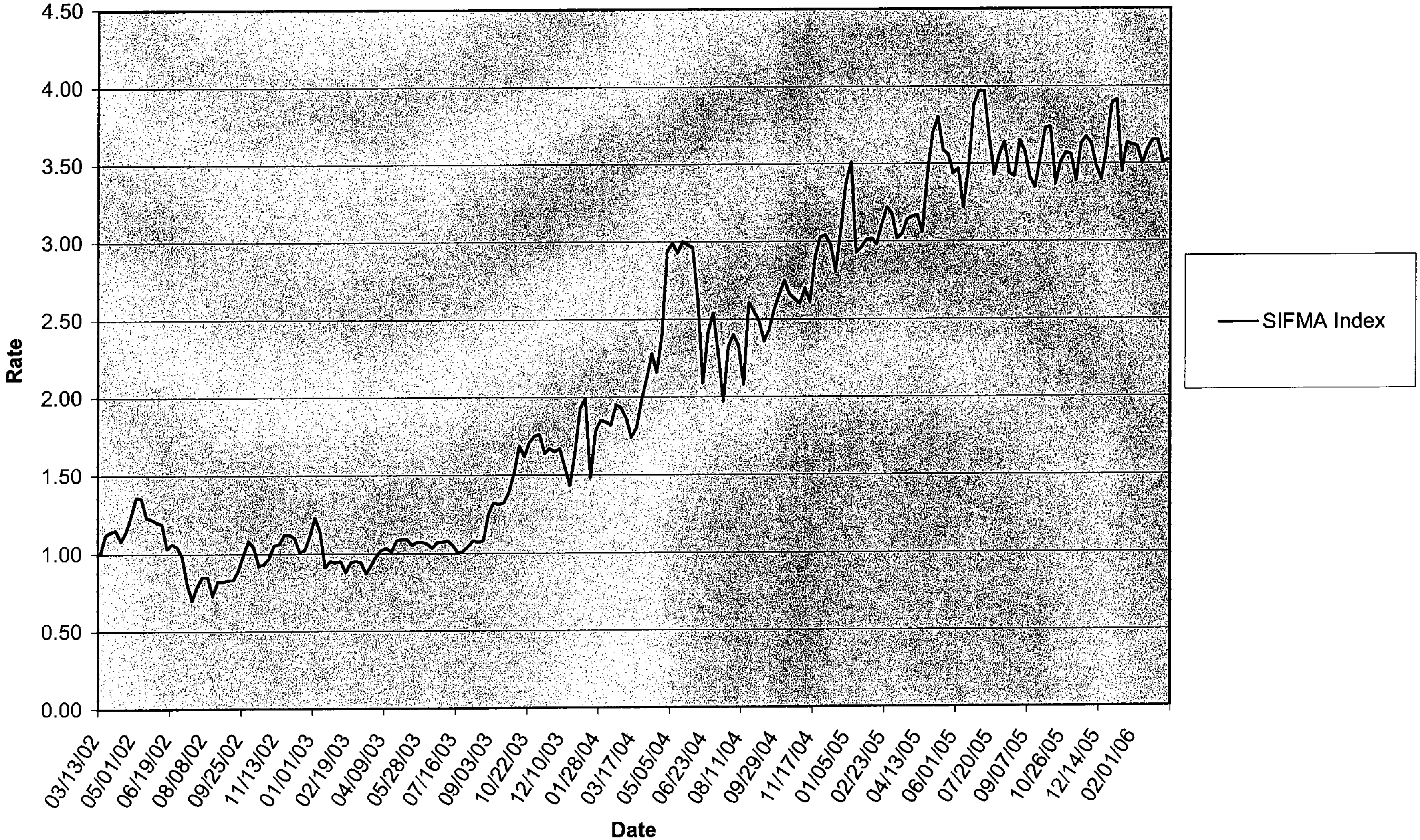

Exhibit No. 12
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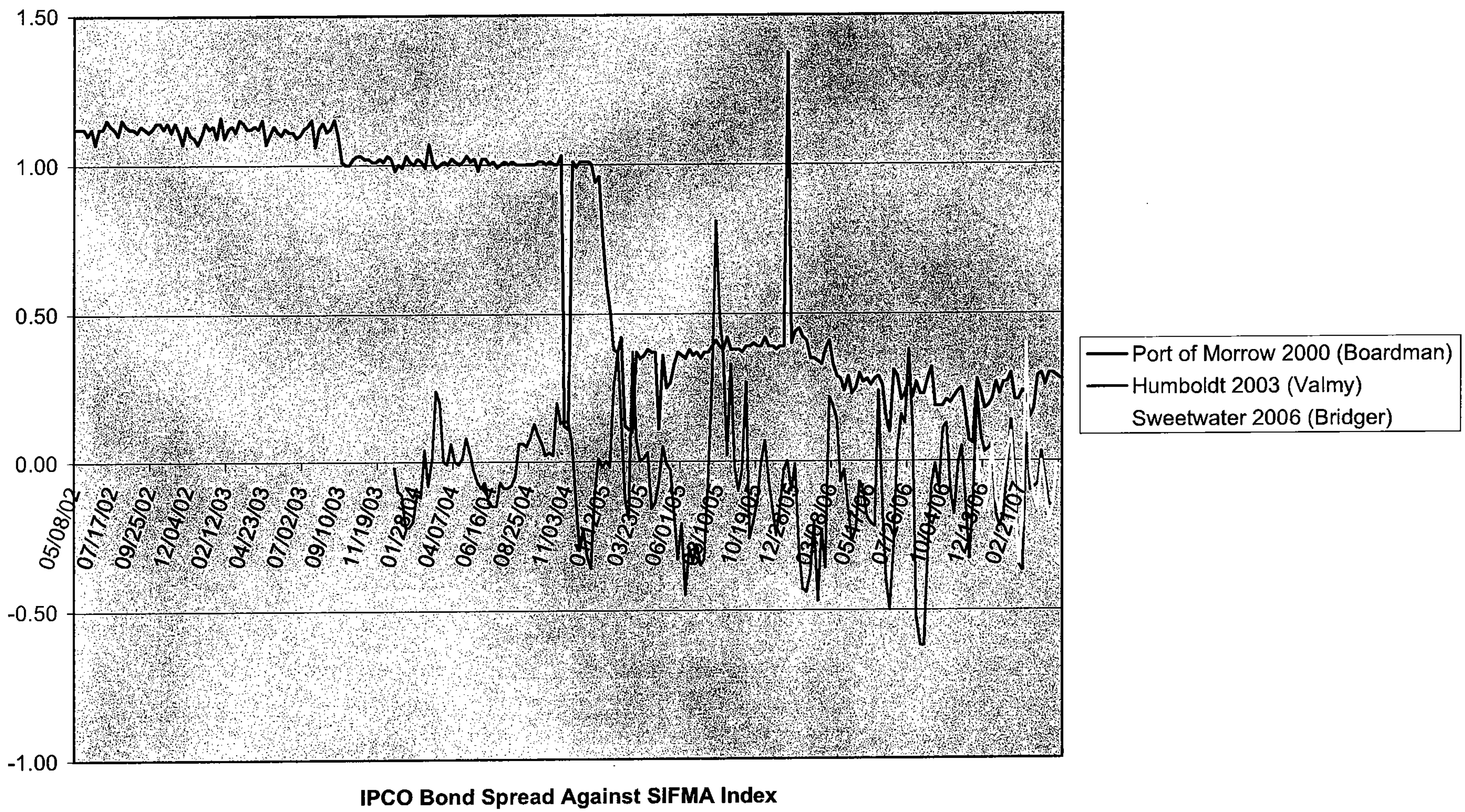
IPCO Variable Rate Bonds Spread Against SIFMA Index
Last 5 Years from 3/7/2007



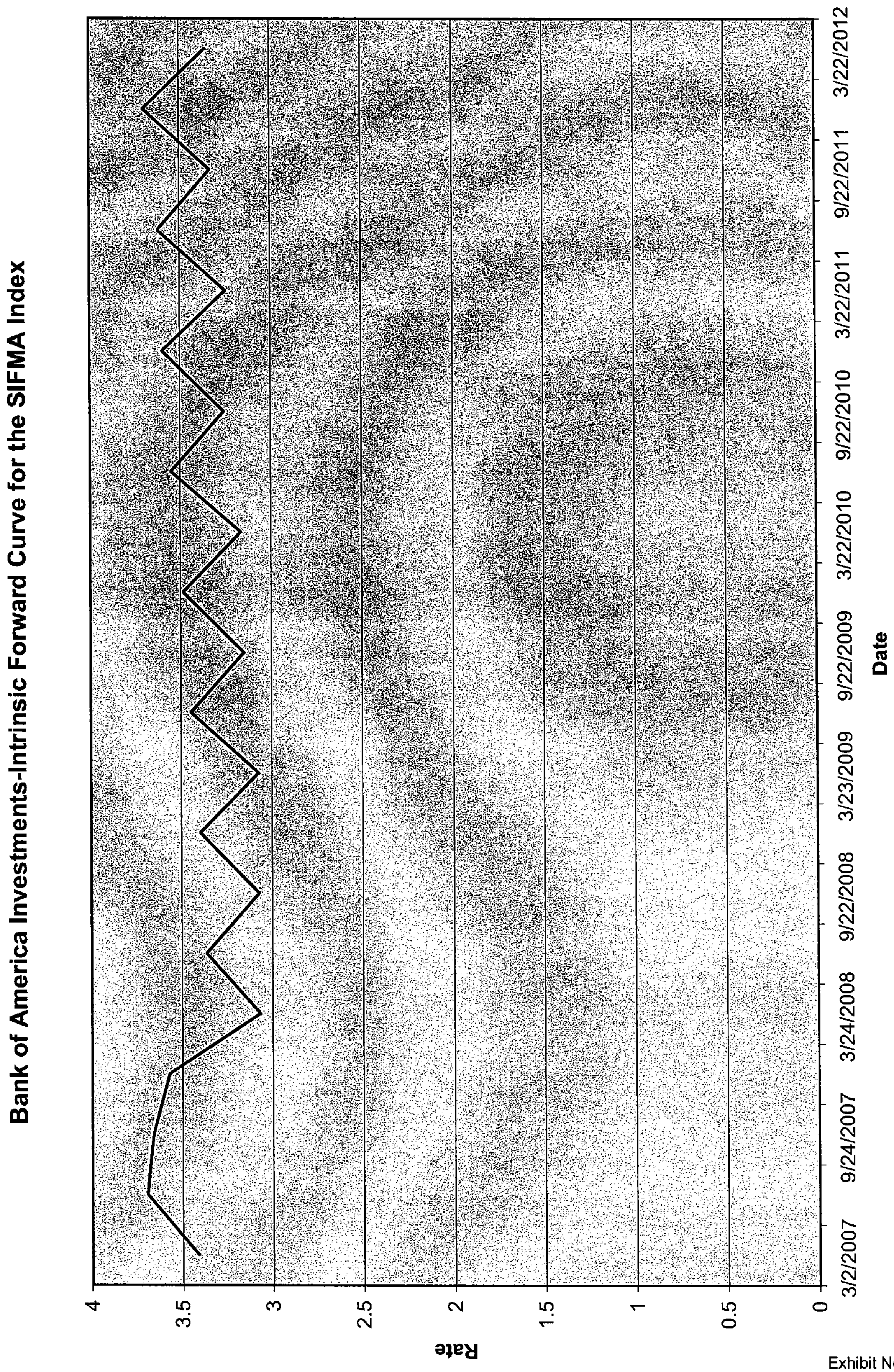


Exhibit No. 14
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S. Keen, IPC
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IDAHO POWER COMPANY FORECASTED 2007 IMPLICIT COUPON RATE FOR VARIABLE RATE DEBT			
As of 3/7/2007			
	[1]	[2]	[1] + [2] = [3]
Instrument	***Average Spread over SIFMA* Index - Last 5 Years***	***Forecasted SIFMA* Forward Rate - 2007 Average *****	***Forecasted 2007 Implicit Coupon Rate***
Port of Morrow 2000 (Boardman)	0.71	3.58	4.29
	[1]	[2]	[1] + [2] = [3]
Instrument	***Average Spread over SIFMA* Index - Last 3 Years***	***Forecasted SIFMA* Forward Rate - 2007 Average *****	***Forecasted 2007 Implicit Coupon Rate***
Humboldt 2003 (Valmy)	-0.07	3.58	3.52
	[1]	[2]	[1] + [2] = [3]
Instrument	***Average Spread over SIFMA* Index - Last 6 Months***	***Forecasted SIFMA* Forward Rate - 2007 Average *****	***Forecasted 2007 Implicit Coupon Rate***
Sweetwater 2006 (Bridger)	-0.07	3.58	3.52
*NOTE: The Securities Industry And Financial Markets Municipal Swap Index			
**NOTE: Calculation for the Forecasted SIFMA Forward Rate - 2007 Average			
Date	**BofA Intrinsic Forward Curve**		
3/20/2007	3.412		
6/22/2007	3.694		
9/24/2007	3.659		
12/24/2007	3.571		
Average for 2007	3.584		