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-05-28

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

WILLIAM E. AVERA

TABLE OF CONTENTS

(For Convenience of Reader)

I. INTRODUCTION 1

A. Overview 1
B. Summary of Conclusions 4

II. FUNDAMENTAL ANALYSES 9

A. Operations & Finances 9
B. Utility Industry 14
C. Risks of Idaho Power 19

III. CAPITAL MARKET ESTIMATES 37

A. Overview 38
B. Results of Quantitative Analyses 42
C. Proxy Group Cost of Equity 49

IV. RETURN ON EQUITY FOR IDAHO POWER 52

A. Implications for Financial Integrity 53
B. Changes Since Case No. IPC-E-03-13 58
C. Conclusions 61

Exhibit WEA-1 - Qualifications of William E. Avera
Exhibit WEA-2 - Capital Structure
Exhibit WEA-3 - Risk Premium - Authorized Rates of Return
Exhibit WEA-4 - Risk Premium - Realized Rates of Return
Exhibit WEA-5 - CAPM - Forward-looking Risk Premium
Exhibit WEA-6 - CAPM - Historical Risk Premium
Exhibit WEA-7 - DCF - Expected Dividend Yield
Exhibit WEA-8 - DCF - Earnings Growth Rates
Exhibit WEA-9 - DCF - Sustainable Growth Rate

I. INTRODUCTION

Q. Please state your name and business address.

A. William E. Avera, 3907 Red River, Austin, Texas, 78751.

Q. In what capacity are you employed?

A. I am the President of FINCAP, Inc., a firm providing financial, economic, and policy consulting services to business and government.

Q. Please describe your educational background and professional experience.

A. A description of my background and qualifications, including a resume containing the details of my experience, is attached as Exhibit WEA-1.

A. Overview

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

A. The purpose of my testimony is to present to the Idaho Public Utilities Commission (the "Commission" or "IPUC") my independent evaluation of the fair rate of return on equity ("ROE") for the jurisdictional utility operations of Idaho Power Company ("Idaho Power" or "the Company").

1 Q. Please summarize the basis of your knowledge
2 and conclusions concerning the issues to which you are
3 testifying in this case.
4 A. As is common and generally accepted in my
5 field of expertise, I have accessed and used information
6 from a variety of sources. I am familiar with the
7 organization, operations, finances, and operation of Idaho
8 Power from my participation in prior proceedings before the
9 IPUC and the Oregon Public Utility Commission. In
10 connection with the present filing, I considered and relied
11 upon corporate disclosures and management discussions,
12 publicly available financial reports and filings, and other
13 published information relating to the Company and its
14 parent, IDACORP, Inc. ("IDACORP"). I also reviewed
15 information relating generally to current capital market
16 conditions and specifically to current investor perceptions,
17 requirements, and expectations for the Company's utility
18 operations. These sources, coupled with my experience in
19 the fields of finance and utility regulation, have given me
20 a working knowledge of investors' ROE requirements for Idaho
21 Power as it competes to attract capital, and form the basis
22 of my analyses and conclusions.
23 Q. What is the role of ROE in setting a
24 utility's rates?

1 A. The rate of return on common equity serves to
2 compensate investors for the use of their capital to finance
3 the plant and equipment necessary to provide utility
4 service. Investors will only commit money if they expect to
5 earn a return on their investment that is commensurate with
6 what is available from other investment alternatives of
7 comparable risks. Consistent with both sound regulatory
8 economics and the standards specified in the *Bluefield*[1] and
9 *Hope*[2] cases, the return on investment allowed a utility
10 should be sufficient to: 1) fairly compensate capital
11 invested in the utility, 2) enable the utility to offer a
12 return adequate to attract new capital on reasonable terms,
13 and 3) maintain the utility's financial integrity.
14 Q. How did you go about developing your
15 conclusions regarding a fair rate of return for Idaho Power?
16 A. I first reviewed the operations and finances
17 of Idaho Power and the general conditions in the utility
18 industry and the economy. With this as a background, I
19 conducted various well-accepted quantitative analyses to
20 estimate the current cost of equity for a benchmark group of
21 western utilities, including alternative risk premium

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[1] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n,* 262 U.S. 679 (1923).
[2] *Fed. Power Comm'n v. Hope Natural Gas Co.,* 320 U.S. 591 (1944).

analyses, an application of the discounted cash flow ("DCF") model, and reference to comparable earned rates of return expected for utilities and industrial firms. Based on the cost of equity estimates indicated by my analyses, the Company's ROE was evaluated taking into account the relative strengths and weaknesses of the alternative methods and the specific risks and economic requirements for Idaho Power, consistent with preservation of its financial integrity.

B. Summary of Conclusions

Q. What are your findings regarding investors' required rate of return on equity for Idaho Power?

A. I conclude that a fair rate of return on equity for Idaho Power falls in the range of 11.0% to 12.0%.

Q. Dr. Avera, what are the salient factors that should be considered in evaluating a fair rate of return on equity for Idaho Power?

A. Idaho Power must compete for investors' capital with other utilities and businesses of comparable risk. If the Company is not provided an opportunity to earn a return that is sufficient to compensate for the underlying risks, investors will be unwilling to supply capital. There are two broad categories of risks that form the backdrop for

an evaluation of investors' required return and should be considered in establishing an ROE for Idaho Power:

1. Market Risks:

- Investors recognize that utilities continue to face the potential for volatile commodity prices, especially in the west;
- For utilities that rely on hydro generation, these uncertainties are compounded by exposure to the negative impact of ongoing drought conditions;
- In the wake of the western power market crisis, the risk that investors associate with utilities has shifted sharply higher, which has only heightened the importance of supportive regulatory actions; and
- A widely anticipated increase in interest rates implies higher capital costs when rates established in this proceeding will go into effect.

2. Risks of Idaho Power:

- Idaho Power's credit standing is under pressure at a time when the Company must support relicensing of key hydroelectric facilities and significant capital expenditures required to meet the growth and reliability needs of its service area;
- Since over one-half of Idaho Power's energy requirements are provided by hydroelectric generation, the Company is exposed to additional risks that other utilities do not face;
  - During times of reduced stream flows, Idaho Power is forced to rely more heavily on purchased power or more costly thermal generation;
  - In the aftermath of the crisis in western wholesale power markets, investors equate this exposure to potential volatility in wholesale energy markets with higher investment risk;
- Investors view Idaho Power's Power Cost Adjustment Mechanism ("PCA") as supportive of the Company's financial integrity, but they understand that the

PCA does not apply to 100% of power costs; nor does it insulate Idaho Power from the need to finance accrued power production and supply costs or shield the Company from potential regulatory disallowances.

Q. Why is it so critical to consider these risks in establishing a fair rate of return for Idaho Power in this case?

A. Providing Idaho Power with the opportunity to earn a return that reflects these realities is an essential ingredient to bolster the Company's financial position, which ultimately benefits customers by ensuring reliable service at lower long-run costs. There are compelling reasons why the IPUC should support Idaho Power's efforts to maintain its financial integrity by authorizing an adequate ROE:

- The financial impact of an inadequate ROE would almost certainly lead to further downgrades, which implies higher capital costs and reduced financial flexibility;
- Idaho Power must access the capital markets to fund significant capital expenditures to maintain and enhance its utility system, with improved financial strength translating into lower borrowing rates and lower long-run financing costs;
- The challenges that have recently characterized the utility industry illustrate the need to ensure that Idaho Power has the ability to respond effectively to unforeseen events.

Ultimately, it is customers and the service area economy that enjoy the rewards that come from ensuring that the

1 utility has the financial wherewithal to take whatever
2 actions are necessary to provide a reliable energy supply.
3 Q. In summary, why is it so important for the
4 IPUC to establish a sufficient return on equity, along with
5 an appropriate capital structure?
6 A. In order for the Company to maintain its
7 financial strength, a sufficient return on equity must be
8 approved, together with an appropriate capital structure.
9 As discussed later in my testimony, and in the testimony of
10 Mr. Gribble, in addition to its longer-term financing needs,
11 Idaho Power has significant capital requirements associated
12 with meeting the needs of its growing service area and
13 ensuring continued reliability. Accordingly, it is
14 important to bolster Idaho Power's financial standing in
15 order to attract capital to fund the Company's commitments
16 at the lowest cost.
17 Q. Do developments since Idaho Power's last rate
18 proceeding (IPC-E-03-13) support an increase in the
19 Company's rate of return on equity?
20 A. Yes. First, the fact that Idaho Power's
21 credit ratings have been lowered indicates that a higher ROE
22 will be required to maintain the Company's financial
23 standing and compensate investors for bearing greater risks.
24 Second, expected capital market conditions indicate a higher

interest rate environment and an increase in capital costs. Third, the investment community's concern indicates their perception that the current authorized ROE falls well short of returns available from alternatives of comparable risk. Fourth, the uncertainties inherent with Idaho Power's operations and the pressures associated with significant capital requirements have become increasingly apparent to investors.

Q. After considering these factors, what were your conclusions regarding a fair ROE and capital structure for Idaho Power?

A. In light of these considerations, I concluded that a fair rate of return on equity for Idaho Power is in the 11.0% to 12.0% range. I based this conclusion on the results of quantitative analyses of the cost of equity for a proxy group of other western utilities, and in light of Idaho Power's relative risks:

- My analyses weighed the results of alternative methods, as well as expectations for higher interest rates;
- After incorporating a 20 basis point allowance for flotation costs, the results of my analyses for the reference group of western utilities implied a cost of equity range of 11.0% to 12.0%, with a midpoint of 11.5%;

Similarly, I strongly endorse Idaho Power's requested capital structure, which is entirely consistent

1 with the average capitalization for the proxy group used to
2 estimate the cost of equity and contains less equity than is
3 projected for these reference utilities over the near-term.

4 **II. FUNDAMENTAL ANALYSES**

5 Q. What is the purpose of this section?

6 A. As a predicate to my economic and capital
7 market analyses, this section examines conditions in the
8 utility industry generally, and for Idaho Power
9 specifically, that investors consider in evaluating their
10 required rate of return. An understanding of these
11 fundamental factors, which drive the risks and prospects for
12 Idaho Power, is essential to develop an informed opinion
13 about investor expectations and requirements that form the
14 basis of a fair rate of return on equity.

15 **A. Operations & Finances**

16 Q. Briefly describe Idaho Power.

17 A. Idaho Power is a wholly-owned subsidiary of
18 IDACORP and is principally engaged in providing integrated
19 retail electric utility service in a 24,000 square mile area
20 in southern Idaho and eastern Oregon. During the most
21 recent fiscal year, Idaho Power's energy deliveries totaled
22 16.1 million megawatt hours ("mWh"). Sales to residential
23 customers comprised 35% of retail sales, with 27% to

1 commercial, 25% to industrial end-users, and 13%
2 attributable to irrigation pumping. Idaho Power also
3 supplies firm wholesale power service to various utilities
4 and municipalities, as well as three large customers under
5 sales contracts. At year-end 2004, Idaho Power had total
6 assets of $3.0 billion and during the most recent fiscal
7 year total revenues amounted to approximately $820 million.
8 Idaho Power's existing generating units include 17
9 hydroelectric generating plants located in southern Idaho.
10 The electrical output of its hydroelectric plants is
11 dependent on stream flows, which have fallen significantly
12 below normal levels in recent years. Although Idaho Power
13 estimates that hydroelectric generation is capable of
14 supplying 55% of total system requirements under normal
15 conditions, the Company has experienced persistent below-
16 normal water conditions. Fluctuations in the output of the
17 Company's hydroelectric generating facilities due to
18 variable water conditions force Idaho Power to rely more
19 heavily on more costly fossil fuels and wholesale power
20 markets to meet its customers' energy needs.
21 Additionally, Idaho Power's hydroelectric facilities
22 are subject to licensing under the Federal Power Act, which
23 is administered by FERC, as well as the Oregon Hydroelectric
24 Act. Relicensing is not automatic under federal law, and

1 Idaho Power must demonstrate that it has operated its
2 facilities in the public interest, which includes adequately
3 addressing environmental concerns. The most significant of
4 Idaho Power's relicensing efforts concerns its Hells Canyon
5 Complex, which represents 68% of the Company's hydro
6 capacity and 40% of its total generating capability.
7 After a prolonged period of planning and
8 consultation with interested parties, Idaho Power has
9 submitted a license application for the Hells Canyon complex
10 that includes various protection, mitigation, and
11 enhancement measures in order to address environmental
12 concerns while preserving the peak and load following
13 operations of the facilities. The estimated cost of these
14 measures is $106 million in the first five years of the
15 license and $218 million over the following twenty-five
16 years, or a total estimated cost of $324 million. The
17 relicensing process is complex, protracted, and expensive.
18 As of June 30, 2005, Idaho Power had accumulated $71 million
19 of construction work in progress associated with its Hells
20 Canyon relicensing efforts.
21 Q. How are fluctuations in Idaho Power's
22 operating expenses caused by varying hydro and power market
23 conditions accommodated in its rates?

1 A. Beginning in May 1993, Idaho Power
2 implemented a PCA, under which rates are adjusted annually
3 to reflect changes in variable power production and supply
4 costs. When hydroelectric generation is reduced and power
5 supply costs rise above those included in base rates, the
6 PCA allows Idaho Power to increase rates to recover a
7 portion of its additional costs. Conversely, if increased
8 hydroelectric generation were to lead to lower power supply
9 costs, rates would be reduced. Although the PCA provides
10 for rates to be adjusted annually, it applies to 90% of the
11 deviation between actual power supply costs and normalized
12 rates. At year-end 2004, the net amount of Idaho
13 jurisdictional power supply costs deferred under the PCA
14 mechanism totaled approximately $47.5 million.
15 Q. What credit ratings have been assigned to
16 Idaho Power?
17 A. Citing concerns over the impacts of a
18 sustained drought, the outcome of Idaho Power's last rate
19 proceeding, and the pressures of ongoing capital
20 requirements, Standard & Poor's Corporation ("S&P") lowered
21 Idaho Power's corporate credit rating from "A-" to "BBB+" in

1 November 2004.[3] Moody's Investors Service ("Moody's) also
2 downgraded the Company's issuer rating from "A3" to "Baa1"
3 based on similar concerns.[4] While Fitch Ratings Ltd.
4 ("Fitch") does not publish a corporate credit rating for
5 Idaho Power, it followed suit and downgraded the Company's
6 senior debt ratings one notch in February 2005.[5]
7 Q. Does Idaho Power anticipate the need to
8 access the capital markets going forward?
9 A. Most definitely. Idaho Power will require
10 capital investment to meet customer growth, provide for
11 necessary maintenance and replacements of its utility
12 infrastructure, as well as fund new investment in electric
13 generation, transmission and distribution facilities. Idaho
14 Power's service area has experienced strong population
15 growth, and the Company's most recent resource plan
16 anticipates the addition of 10,000 new customers annually.[6]
17 In order to keep pace with customer growth, enhance
18 transmission infrastructure, and balance generation resource
19 uncertainty Idaho Power anticipates construction

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[3] Standard & Poor's Corporation, "IDACORP and Unit Ratings Lowered, Removed From CreditWatch Negative," *RatingsDirect* (Nov. 29, 2004).
[4] Moody's Investors Service, "Ratings Action: IDACORP, Inc.," *Global Credit Research* (Dec. 3, 2004).
[5] Fitch Ratings Ltd., "Idaho Power Company," *Global Power/North America Credit Analysis* (Feb. 18, 2005).
[6] Idaho Power Company, *2004 Integrated Resource Plan* (July 2004) at 8.

1 expenditures of approximately $672 million over the 2005-
2 2007 period alone.[7]
3 Over the longer-term, Idaho Power's Integrated
4 Resource Plan has identified the potential need for the
5 Company to finance construction of approximately 500 MW of
6 additional baseload generation, in addition to other system
7 upgrades.[8] Moreover, as indicated earlier, protection,
8 mitigation, and enhancement measures associated with Hells
9 Canyon relicensing are estimated to total $324 million.
10 Considering the recent deterioration in the Company's credit
11 standing, support for Idaho Power's financial integrity and
12 flexibility will be instrumental in attracting the capital
13 necessary to fund these projects in an effective manner.

14 **B. Utility Industry**

15 Q. What general conditions have recently
16 characterized the utility industry?
17 A. Over the past decade, the industry has
18 experienced significant structural change resulting from
19 market forces and decontrol initiatives. At least
20 initially, this process was largely driven by regulatory
21 reforms at the federal level. The National Energy Policy

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[7] IDACORP, Inc., *2nd Quarter 2004 Form 10-Q Report* (June 30, 2005).
[8] *Id.* at 84.

1 Act of 1992 greatly increased prospective competition for
2 the production and sale of power at the wholesale level,
3 with FERC being an aggressive proponent for actions designed
4 to foster greater competition in markets for wholesale power
5 supply.
6 Most market observers agree that, while "open
7 access" to FERC-jurisdictional transmission facilities has
8 resulted in more competition in wholesale energy markets, it
9 has also introduced substantial risks - particularly for
10 utilities (like Idaho Power) that depend on wholesale
11 markets for a portion of their resource requirements.
12 Q. What impact did the western power crisis have
13 on investors' risk perceptions for firms involved in the
14 electric power industry?
15 A. Events of the last several years caused
16 investors to rethink their assessment of the relative risks
17 associated with the electric power industry. A well-
18 publicized energy crisis throughout the west wreaked havoc
19 on the customers, utilities, and policymakers. It also had
20 dramatic repercussions for western wholesale power markets
21 and investors and utilities nationwide. State regulators
22 and legislators in many jurisdictions have re-evaluated
23 restructuring initiatives for the retail sector of the
24 electric industry and the financial implications of the

1 western power crisis brought the uncertainties associated
2 with today's power markets into sharp focus for the
3 investment community. While the case of California
4 represents an extreme example, there is every indication
5 that investors' risk perceptions for utilities shifted
6 sharply upward in response to these events.
7 Q. Was there a corresponding impact on the
8 industry's credit standing?
9 A. Yes. The last several years witnessed steady
10 erosion in credit quality throughout the utility industry,
11 both as a result of revised perceptions of the risks in the
12 industry and the weakened finances of the utilities
13 themselves. For example, during 2002, S&P recorded 182
14 downgrades in the utility industry, versus only 15
15 upgrades,[9] while Moody's downgraded 109 utility issuers and
16 upgraded 3.[10] Credit quality continued to decline during
17 2003, with S&P reporting that downgrades outpaced upgrades
18 by more than 15 to one in the fourth quarter of 2003.[11]
19 While the pace and scale of negative ratings actions has
20 since diminished, S&P reported that the majority of the

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[9] Standard & Poor's Corporation, "U.S. Power Industry Experiences Precipitous Credit Decline In 2002; Negative Slope Likely to Continue," *RatingsDirect* (Jan. 15, 2003).
[10] Moody's Investors Service, *Credit Perspectives* (Jul. 14, 2003) at 33.
[11] Standard & Poor's Corporation, "U.S. Utilities' Ratings Decline Continued in 2003, But Pace Slows," *RatingsDirect* (Feb. 2, 2004).

1 companies in the utility sector now fall in the triple-B
2 rating category and noted a continued negative bias in the
3 credit outlook.[12]

4 Q. What other developments have contributed to
5 investors' reassessment of the risks associated with the
6 electric utility industry?

7 A. Policy evolution in the electric transmission
8 area has been wide-reaching and investors have increasingly
9 focused on uncertainty over operating rules and market
10 development. Virtually all industry stakeholders have
11 recognized that regulatory uncertainties increase the risks
12 associated with the utility industry. For example, the
13 Department of Energy ("DOE") identified "reducing regulatory
14 uncertainty" as critical in stimulating increased investment
15 in the power industry and has noted that lack of clarity in
16 the regulatory structure was inhibiting planning and
17 investment.[13] The DOE also recognized the impact that this
18 regulatory uncertainty has on investors' required rates of
19 return for electric utilities:

20 Because transmission assets are long lived,
21 regulatory uncertainty increases the risks to
22 investors and, therefore, increases the returns

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[12] Standard & Poor's Corporation, *RatingsDirect* (Jul. 6, 2005, Jul. 29, 2004).
[13] U.S. Department of Energy, *National Transmission Grid Study* (May 2002), at 24 and 31.

> they need to justify transmission system investments.[14]

The 2003 blackout only served to reinforce the importance of regulatory risks for investors. The Wall Street Journal cited the debilitating impact of an "unsteady regulatory environment" and the "chaotic combination of regulated and deregulated markets" in explaining inhibitions to increased investment in the electric utility system.[15]

Q. Are these uncertainties the only risks being faced by utilities?

A. No. Apart from these factors, electric utilities continue to face the normal risks inherent in operating utility systems, including the potential adverse effects of inflation, interest rate changes, growth, the general economy, and regulatory uncertainty and lag. As Fitch Ratings, Ltd. ("Fitch") noted in a survey of the utility industry:

> Taking a longer view, over the coming five years through 2009, the sector will increasingly face some potentially negative factors. These include rising interest rates, higher capital expenditures and volatile commodity prices.[16]

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[14] *Id.* at 31.
[15] Smith, Rebecca, "Overloaded Circuits Blackout Signals Major Weakness in U.S. Power Grid," The Wall Street Journal (Aug. 18, 2003).
[16] Fitch Ratings, Ltd., "Outlook 2005: U.S. Power & Gas," *Global Power North American Special Report* (Jan. 6, 2005) at 2.

1 Electric utilities are confronting increased environmental
2 pressures that leave them exposed to uncertainties regarding
3 emissions and potential contamination. S&P recognized the
4 potential financial challenges posed by such uncertainties:

5 Pension obligations, environmental liabilities,
6 and serious legal problems restrict flexibility,
7 apart from the obligations' direct financial
8 implications.[17]

9 **C. Risks of Idaho Power**

10 Q. How was Idaho Power impacted by the turmoil
11 in the electric power industry?
12 A. Like others, Idaho Power was swept up in the
13 maelstrom of the western energy crisis. Because of Idaho
14 Power's dependence on hydroelectric generation, it has
15 always been exposed to the uncertainties associated with
16 year-to-year fluctuations in water conditions.
17 Nevertheless, the degree of price volatility that Idaho
18 Power was forced to assume was unprecedented and variability
19 in short-term market prices bore no resemblance to
20 fluctuations experienced in the past.
21 Increased wholesale prices and rate structures that
22 did not capture full costs of acquiring fuel and purchased
23 power led to depressed earnings. To varying degrees,

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[17] Standard & Poor's Corporation, *Corporate Ratings Criteria* at 29, available at www.standardandpoors.com/ratings.

1 utilities throughout the western U.S. were confronted with
2 the difficult task of maintaining reliable service and
3 financial integrity in a power market characterized by short
4 supply and unprecedented price volatility. Because of low
5 stream flows available to Idaho Power's hydroelectric
6 facilities and the resulting dependence on wholesale power
7 markets in the west, the chaotic market conditions were felt
8 directly.
9 Q. Are investors likely to consider the impact
10 of industry uncertainty in assessing their required rate of
11 return for Idaho Power?
12 A. Absolutely. While utility restructuring has
13 not been actively pursued in Idaho, Idaho Power continues to
14 face the prospect of FERC driven changes in the electric
15 transmission function of their business, as well as other
16 fundamental industry reforms. Moreover, because roughly
17 one-half of Idaho Power's total energy requirements are
18 provided by hydroelectric facilities, the Company is exposed
19 to a level of uncertainty not faced by most utilities.
20 While hydropower confers advantages in terms of fuel cost
21 savings and diversity, reduced hydroelectric generation due
22 to below-average water conditions forces Idaho Power to rely
23 more heavily on purchased power or more costly thermal
24 generating capacity to meet its resource needs.

1 Additionally, in recent years utilities and their customers
2 have also had to contend with dramatic fluctuations in gas
3 costs due to ongoing price volatility in the spot markets.[18]
4 The IPUC acknowledged these trends in connection with its
5 approval of a 32% increase in the weighted average cost of
6 gas for Intermountain Gas Company ("Intermountain Gas"):

7 Wholesale natural gas prices have continued to
8 fluctuate dramatically. The volatile natural gas
9 market has seen forecasts of future costs at
10 record levels, and resulted in increased
11 uncertainty about when and where prices will
12 stabilize.[19]

13 In the minds of investors, dependence on wholesale
14 markets entails significant risk, especially for a utility
15 located in the west. Investors recognize that volatile
16 energy markets, unpredictable stream flows, and Idaho
17 Power's reliance on wholesale purchases to meet a portion of
18 its resource needs can create a "perfect storm," exposing
19 the Company to the risk of reduced cash flows and
20 unrecovered power supply costs. Idaho Power's reliance on
21 purchased power to meet shortfalls in hydroelectric
22 generation magnifies the importance of strengthening

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[18] For example, the Energy Information Administration ("EIA") reported (Mar. 27, 2003) that the average spot gas price at the Henry Hub spiked to $18.85 per MMBtu in February 2003, before declining to approximately $5.00. More recently, EIA noted that "prices at the Henry Hub on Wednesday, October 12 exceeded last year's level by $8.36 per MMBtu or about 156 percent." (*Natural Gas Weekly Update,* Oct. 13, 2005).
[19] *Idaho Public Utilities Commission*, Order No. 29875 (Sep. 29, 2005) at 7.

1 financial flexibility, which is essential to guarantee
2 access to the cash resources and interim financing required
3 to cover inadequate operating cash flows, as well as fund
4 required investments in the utility system.
5 Q. Have the risks of market volatility
6 dissipated since the crisis in 2000-2001?
7 A. No. Investors recognize that the continuing
8 prospect of further turmoil in western energy markets cannot
9 be discounted, with S&P reporting continued spikes in
10 wholesale market prices in the aftermath of the crisis:

11 For 2003, record-high wholesale power prices were
12 the defining feature of the U.S. merchant power
13 markets. ... Power prices across the U.S.
14 continent generally rose on the order of 50% or
15 more in 2003. ... Prices in the western regions
16 were also the highest on record outside of the
17 2000-2001 California energy crisis.[20]

18 More recently, S&P noted that, while the severe
19 distortions that characterized the energy crisis of 2000-
20 2001 have faded, "[n]atural gas volatility, poor hydro
21 conditions in the Northwest, the Southwest's sustained
22 drought, and uncertainty over future generation development"
23 are "daily reminders" of the challenges to the financial

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[20] Standard & Poor's Corporation, "Energy Commodity Report: U.S. Power Prices Record High in 2003," *RatingsDirect* (Jan. 15, 2004).

1 health of western utilities.[21] S&P noted the danger posed
2 by "high and volatile natural gas prices," which increase
3 the uncertainties associated with power supply costs.[22] As
4 the Economist Intelligence Unit, Ltd. indicated, this
5 sensitivity has only been magnified by fallout of the
6 natural disaster in the Gulf Coast region:

7 Hurricane Katrina has sent gas prices to new
8 record levels, exacerbating an already supply-
9 tight market that has seen high prices for the
10 last two years. There is little indication that
11 the situation will improve in 2006...[23]

12 Meanwhile, the FERC Staff has warned of the ongoing
13 potential for market disruption in the west, due in part to
14 constrained hydro generation. As a recent report concluded:

15 Our review of supply and demand conditions in the
16 west this summer indicates that there may be
17 periods of market tightness most likely expressed
18 as price spikes and possible interruptions.[24]

19 S&P observed that utilities in the Pacific Northwest
20 "continue to face a host of challenges,"[25] and went on to
21 note the significant potential costs and risks imposed by

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[21] Standard & Poor's Corporation, *Utilities & Perspectives* (Oct. 18, 2004).
[22] Standard & Poor's Corporation, "Prolonged High Natural Gas Prices May Increase Credit Risk for U.S. Gas Distributors," *RatingsDirect* (Jan. 19, 2005)
[23] Economist Intelligence Unit, Ltd., "World Commodities - Natural gas market outlook," (Sep. 1, 2005) at 1.
[24] Federal Energy Regulatory Commission, Office of Market Oversight and Investigations, "Summer Energy Market Assessment 2005," (May 4, 2005) at 11.
[25] Standard & Poor's Corporation, "Legal Developments Add to Utilities' Disquiet in U.S. Northwest," *Utilities & Perspectives* (July 21, 2003) at 2-3.

uncertainty over fish-conservation measures that might be required to meet federal law and continued volatility in wholesale power markets.[26] S&P concluded that "managing hydro risk has assumed a critical importance to credit quality."[27]

Q. Do recent weather conditions ameliorate investors' concerns?

A. No. Lack of snow and warmer than normal temperatures last winter have only deepened concerns over power prices. The Wall Street Journal observed earlier this year that:

> Regional weather watchers say conditions are starting to resemble those of 2001, when dry weather and a low snowpack brought drought conditions to the Pacific Northwest.[28]

On April 29, 2005, Idaho's Governor issued a drought emergency for Power County, one of 20 county drought declarations for the year, citing sharply reduced flows in the Snake River.[29]

Similarly, Fitch noted that the Pacific Northwest was "in the midst of its sixth consecutive year of well-

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[26] *Id.*
[27] *Id.*
[28] Stepankowsky, Paula L., "Lack of Snow in Pacific Northwest Heightens Worry About Power," The Wall Street Journal (Feb. 16, 2005).
[29] The Governor of the State of Idaho, "Kempthorne Declares Drought Emergency in Power County," *News Release* (April 29, 2005); "Kempthorne Declares Drought Emergency in Lincoln County," *News Release* (June 17, 2005).

below-normal water conditions," with runoff in the Snake River Basin estimated at 60% to 70% of 30-year norms.[30] Fitch recognized that lower stream flows would force greater reliance on more expensive thermal generating facilities and concluded that:

> The adverse financial effect of continued dry weather conditions on load-serving entities (LSEs) in the region is exacerbated by high natural gas prices, which will make replacement power services (i.e., purchased power and operation of natural gas-fired combined cycle) and peaking capacity more expensive.[31]

Investors recognize the significant financial burden associated with prolonged dry weather in the west. As Fitch summarized:

> [T]he duration and severity of the current drought, which stretches back through the energy crisis of 2000-2001, has resulted in meaningful cash flow volatility, balance-sheet erosion and diminished financial flexibility...[32]

From the standpoint of the capital markets, the west is risky - and Idaho Power's continued exposure to wholesale electric and natural gas markets in meeting shortfalls in hydroelectric generation and other variations in resources and loads compound these uncertainties.

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[30] Fitch Ratings Ltd., "Hydro Update," *Global Power/North America Special Report* (June 2, 2005).
[31] *Id.*
[32] *Id.*

1 Q. Does the PCA remove the risk associated with
2 fluctuations in power supply costs?
3 A. No. While the PCA is supportive of Idaho
4 Power's financial integrity, it does not apply to 100% of
5 power costs. Moreover, even for utilities with permanent
6 energy cost adjustment mechanisms in place, there can be a
7 significant lag between the time the utility actually incurs
8 the expenditure and when it is recovered from ratepayers.
9 This lag can impinge on the utility's financial strength
10 through reduced liquidity and higher borrowings. As S&P
11 noted, the PCA does not insulate Idaho Power from the need
12 to finance accrued power production and supply costs:

13 The drought that has affected stream flows in the
14 Snake River is in its fifth year and has raised
15 costs substantially for customers by depressing
16 low-cost hydro output. This has meant that
17 deferred revenues ($71 million as of Dec. 31,
18 2003) never decreased to zero since the time of
19 the western U.S. power crisis.[33]

20 Q. What other factors would investors consider
21 in evaluating the impact of the PCA?
22 A. Idaho Power's PCA applies to 90% of the
23 deviation between actual power supply costs and normalized
24 rates. As originally contemplated, this provision would
25 result in a more or less symmetrical sharing of risks, with

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[33] Standard & Poor's Corporation, "IDACORP and Unit Ratings Lowered, Removed From CreditWatch," *RatingsDirect* (Nov. 29, 2004).

customers reaping the benefits when power costs exceeded normal levels and Idaho Power benefiting when power supplies were obtained at below-normal cost.

However, the confluence of prolonged drought and sharply higher natural gas prices - both of which are beyond the control of Idaho Power's management - has resulted in sustained shortfalls between actual power costs and normalized rates. Combined with the provisions of the PCA, the end result has been that Idaho Power's shareholders have effectively provided customers with a 10% discount towards cost increases for the largest single component in the price of electricity.

In 2003 and 2004, for example, the Company's unrecovered power costs totaled $23.4 million and $13.4 million, respectively.[34] Moreover, with no apparent end to drought conditions, and with the IPUC warning consumers to prepare for "an indefinite period of higher than normal prices for natural gas,"[35] there is no indication that this established pattern will soon reverse. As a result,

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[34] While these figures include amounts attributable to Idaho Power's Oregon-jurisdictional operations, the majority are associated with the provisions of the PCA in Idaho.

[35] Idaho Public Utilities Commission, "Higher than normal gas prices may be with us for awhile," http://www.puc.state.id.us/ (Retrieved Oct. 19, 2005).

1 investors undoubtedly consider this exposure in evaluating
2 Idaho Power's risks and their required rate of return.
3 Q. Does the PCA protect Idaho Power from the
4 potential for regulatory disallowances?
5 A. No. Even with an energy cost adjustment
6 mechanism, investors recognize the ongoing potential for
7 regulatory disallowances. As S&P observed:

8 [Fuel and purchased power adjustment mechanisms
9 (FPPA)] vary substantially in their ability to
10 protect utilities daily and under catastrophic
11 market movements. Moreover, it is critical to
12 note that FPPAs are not a substitute for
13 supportive regulation; the regulator's ability to
14 disallow costs through ex-post prudency review,
15 regardless of the existence of a FPPA, is a fact
16 of life for utilities.[36]

17 Similarly, Fitch noted that "because of the lag
18 between when the excess costs are incurred and when they are
19 recovered and the potential disallowances of such costs,"
20 substantial uncertainties remain even for utilities with
21 fuel and purchased power cost adjustment mechanisms.[37]
22 Significantly, Fitch specifically highlighted Idaho Power as
23 one of 29 utilities having "relatively greater fuel or
24 purchased power exposure within the sector"[38] and cited the

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[36] Standard & Poor's Corporation, *Utilities & Perspectives* (Oct. 18, 2004).
[37] Fitch Ratings Ltd., "Outlook 2005: U.S. Power & Gas," *Global Power/North America Special Report* (Jan. 6, 2005) at 26.
[38] *Id.* at 27.

1 "earnings volatility inherent in the utility's hydro
2 generation system" as a primary factor in its decision to
3 downgrade Idaho Power's senior debt ratings.[39]
4 Q. Is an evaluation of the capital structure
5 maintained by a utility relevant in assessing its return on
6 equity?
7 A. Yes. Other things equal, a higher debt
8 ratio, or lower common equity ratio, translates into
9 increased financial risk for all investors. A greater
10 amount of debt means more investors have a senior claim on
11 available cash flow, thereby reducing the certainty that
12 each will receive his contractual payments. This increases
13 the risks to which lenders are exposed, and they require
14 correspondingly higher rates of interest. From common
15 shareholders' standpoint, a higher debt ratio means that
16 there are proportionately more investors ahead of them,
17 thereby increasing the uncertainty as to the amount of cash
18 flow, if any, that will remain.
19 Q. What common equity ratio is implicit in Idaho
20 Power's requested capital structure?
21 A. Idaho Power's capital structure is presented
22 in the testimony of Mr. Gribble and Ms. Smith. As

[39] Fitch Ratings Ltd., "Idaho Power Company," *Global Power/North America Credit Analysis* (Feb. 18, 2005) at 1.

1 summarized in their testimony, the common equity ratio used
2 to compute Idaho Power's overall rate of return was 49.462%
3 in this filing.
4 Q. What was the average capitalization
5 maintained by the reference group of utilities?
6 A. As shown on Exhibit WEA-2, for the ten firms
7 in the proxy group, common equity ratios at December 31,
8 2004 ranged from 37.2% to 65.8% and averaged 49.7%.
9 Q. What implication does the increasing risk of
10 the utility industry have for the capital structures
11 maintained by utilities?
12 A. The decline in credit quality in the electric
13 industry is indicative of the need for utilities to
14 strengthen their balance sheets to deal with an increasingly
15 uncertain and competitive market. S&P cited higher debt
16 leverage and the inadequacy of financial profiles in the
17 electric industry as one of the key factors explaining this
18 deterioration. A more conservative financial profile is
19 consistent with increasing uncertainties and the need to
20 maintain the continuous access to capital that is required
21 to fund operations and necessary system investment, even
22 during times of adverse capital market conditions.
23 As shown on Exhibit WEA-2, the Value Line Investment
24 Survey ("Value Line") expects that the average common equity

1 ratio for the proxy group of western utilities will increase
2 to 55.6% over the next three to five years.
3 Q. How does Idaho Power's common equity ratio
4 compare with those maintained by the reference group of
5 utilities?
6 A. Idaho Power's 49.462% common equity ratio is
7 entirely consistent with the 49.7% average for the proxy
8 group at year-end 2004 and falls well short of the 55.6%
9 equity ratio based on Value Line's expectations for these
10 western utilities over the near-term.
11 Q. How does Idaho Power's capital structure
12 compare with other widely cited financial benchmarks for
13 utilities?
14 A. The financial ratio guidelines published by
15 S&P specify a range for a utility's total debt ratio that
16 corresponds to each specific bond rating. Widely cited in
17 the investment community, these ratios are viewed in
18 conjunction with a utility's *business profile* ranking, which
19 ranges from 1 (strong) to 10 (weak) depending on a utility's
20 relative business risks. Thus, S&P's guideline financial
21 ratios for a given rating category (e.g., triple-B) vary
22 with the business or operating risk of the utility. In
23 other words, a firm with a *business profile* of "2" (*i.e.*,
24 relatively lower business risk) could presumably employ more

1 financial leverage than a utility with a business profile
2 assessment of "9" while maintaining the same credit rating.
3 S&P has assigned Idaho Power a *business profile* ranking of
4 "5".[40]
5 Consistent with an S&P *business profile* ranking of
6 "5", a ratio of total debt to total capital in the range of
7 50% to 60% is specified for a triple-B bond rating, which
8 translates to an equity ratio between 40% and 50%.[41]
9 Q. What other factors do the rating agencies
10 consider in their assessment of a company's capital
11 structure?
12 A. Because power purchase agreements("PPAs")
13 typically obligate the utility to make specified minimum
14 contractual payments akin to those associated with
15 traditional debt financing, investors consider a portion of
16 these commitments as debt in evaluating total financial
17 risks. Further, changes in financial accounting standards
18 also result in adjustments that have the effect of further
19 increasing financial leverage. Because bond ratings
20 agencies and investors adjust for these various commitments

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[40] Standard & Poor's Corporation, "U.S. Utility and Power Ranking List," *RatingsDirect* (May 13, 2005).
[41] Standard & Poor's Corporation, "New Business Profile Scores Assigned for U.S. Utility and Power Companies; Financial Guidelines Revised," (June 2, 2004) at Table 1.

1 in assessing a utility's financial position, they imply
2 greater risk and reduced financial flexibility.
3 Q. Do mandated PPA's with PURPA Qualifying
4 Facilities ("QF's") have a similar impact?
5 A. Yes. When a utility enters into a PPA with a
6 QF, the fixed charges associated with the contract increase
7 the utility's financial risk in the same way that long-term
8 debt and other financial obligations increase financial
9 leverage. Under current accounting rules, the accounting
10 for a PPA is not discretionary if the transaction meets
11 specified tests for accounting for capital leases, which
12 require that the obligation be explicitly recorded as a debt
13 obligation on the utility's balance sheet.
14 As a result, the utility must rebalance its capital
15 structure by increasing its common equity in order to
16 restore its capitalization ratios to previous levels. Since
17 the cost of equity exceeds the cost of debt, this
18 rebalancing imposes additional costs, which are properly
19 considered by regulators.
20 Q. Do QF PPAs that do not meet the accounting
21 definition for capital lease treatment still impact
22 investors' assessment of Idaho Power's financial risks?
23 A. Yes. The accounting standards simply reflect
24 the longstanding perception of investors that the fixed

1 obligations associated with PPAs diminish a utility's
2 creditworthiness and financial flexibility. The
3 implications of purchased power commitments have been
4 repeatedly cited by major bond rating agencies in connection
5 with assessments of utility financial risks.
6 For example, in reviewing its evaluation of the
7 credit implications of PPAs, S&P affirmed its position that
8 such agreements are "debt-like in nature" and that the
9 increased financial risk must be considered in evaluating a
10 utility's credit risks.[42] As the rating agency explained:

11 [P]urchased power agreements typically result in
12 the assumption of fixed costs representing the
13 portion of the purchase price that is linked to
14 the capacity component of the total payment.
15 These fixed capacity payments are similar to debt
16 service payments incurred by a utility that
17 constructs debt-financed power generation
18 facilities. Therefore, whether a utility builds
19 its own generating plants, or enters into a long-
20 term power purchase agreement with a fixed-cost
21 component, that utility is taking on financial
22 risk.[43]

23 When evaluating Idaho Power's financial risks, investors
24 likewise recognize that the Company's contractual payment
25 obligations to QFs are fixed commitments with debt-like
26 characteristics.

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[42] Standard & Poor's Corporation, "'Buy Versus Build': Debt Aspects of Purchased Power Agreements," *Utilities & Perspectives* (May 12, 2003).
[43] Standard & Poor's Corporation, *RatingsDirect* (Nov. 6, 2003).

1 Indeed, payment obligations under Idaho Power's
2 existing PPAs with QFs currently total approximately $46.4
3 million. Unless Idaho Power takes action to offset this
4 additional financial risk, the resulting leverage lowers the
5 Company's creditworthiness and places downward pressure on
6 its ratings. QF PPAs thus potentially increase investors'
7 required rate of return for Idaho Power's debt and equity
8 securities.[44]
9 Q. What does this evidence suggest with respect
10 to Idaho Power's proposed capital structure?
11 A. While industry averages provide one benchmark
12 for comparison, each firm must select its capitalization
13 based on the risks and prospects it faces, as well its
14 specific needs to access the capital markets. A public
15 utility with an obligation to serve must maintain ready
16 access to capital so that it can meet the service
17 requirements of its customers. The need for access becomes
18 even more important when the company has large capital
19 requirements over a period of years, and financing must be

[44] Apart from the immediate impact that the fixed obligation of purchased power costs has on the utility's financial risk, higher fixed charges also reduce ongoing financial flexibility, and the utility may face other uncertainties, such as potential replacement power costs in the event of supply disruption.

1 continuously available, even during unfavorable capital
2 market conditions.
3 The recent decision of S&P and Fitch to downgrade
4 Central Vermont Public Service ("Central Vermont") from
5 triple-B to below investment grade highlights the importance
6 of maintaining sufficient common equity to preserve the
7 utility's creditworthiness, even during times of stress.
8 Despite a common equity ratio that exceeded 60%, S&P and
9 Fitch determined that Central Vermont's financial position
10 was inadequate to support an investment grade rating in the
11 face of an unfavorable regulatory order.[45]
12 As indicated earlier, the decline in the Company's
13 credit standing and the heightened uncertainty associated
14 with Idaho Power's reliance on hydroelectric generation
15 magnifies the importance of preserving financial
16 flexibility. Under these circumstances, it is essential
17 that Idaho Power's capital structure include adequate
18 borrowing capacity to maintain an ongoing ability to raise
19 capital sufficient to fund planned capital investments and
20 meet its service obligations. While financial flexibility
21 plays a crucial role in ensuring the wherewithal to meet the

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[45] "S&P Downgrades CVPS Corporate Credit Rating," *Business Wire* (June 14, 2005); "Fitch Ratings Downgrades CVPS," *Business Wire* (June 20, 2005).

needs of customers, utilities with higher leverage may be foreclosed from additional borrowing, especially during times of stress. In this regard, Idaho Power's equity ratio reflects the challenges posed by its resource mix, as well as the burden of significant capital spending requirements.

Idaho Power's proposed capital structure is just one reflection of the Company's ongoing efforts to enhance its credit standing and maintain access to capital on reasonable terms in order to ensure its ability to meet its obligations to customers. The reasonableness of Idaho Power's requested capital structure is reinforced by the ongoing uncertainties associated with the electric power industry, the Company's relative risks and circumstances, the need to support continued system investment, and the imperative of maintaining continuous access to capital, even during times of adverse industry and market conditions. As the experience of Central Vermont illustrates, even a healthy equity cushion may not be sufficient to support a utility's credit ratings when investors perceive a lack of regulatory support.

III. CAPITAL MARKET ESTIMATES

Q. What is the purpose of this section?

A. This section presents capital market estimates of the cost of equity for a benchmark group of utilities. The details of my quantitative analyses are contained in my Additional Direct testimony, with the results being summarized below.

A. Overview

Q. What role does the rate of return on common equity play in a utility's rates?

A. The return on common equity is the cost of inducing and retaining investment in the utility's physical plant and assets. This investment is necessary to finance the asset base needed to provide utility service. Investors will commit money to a particular investment only if they expect it to produce a return commensurate with those from other investments with comparable risks. Moreover, the return on common equity is integral in achieving the sound regulatory objectives of rates that are sufficient to: 1) fairly compensate capital investment in the utility, 2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and 3) maintain the utility's financial integrity. Meeting these objectives allows the utility to fulfill its obligation to provide reliable

1 service while meeting the needs of customers through
2 necessary system expansion.
3 Q. What fundamental economic principle underlies
4 any evaluation of investors' required return on equity?
5 A. Underlying the concept of the cost of equity
6 is the fundamental notion that investors are risk averse,
7 and will willingly bear additional risk only if they expect
8 compensation for doing so. As explained in greater detail
9 in my Additional Direct testimony, the required rate of
10 return for a particular asset at any point in time is a
11 function of: 1) the yield on risk-free assets, and 2) its
12 relative risk, with investors demanding correspondingly
13 larger risk premiums for assets bearing greater risk.
14 Because common shareholders have the lowest priority claim
15 on a firm's cash flows, they receive only the residual that
16 remains after all other claimants - employees, suppliers,
17 governments, lenders, have been paid. As a result, the rate
18 of return that investors require from a utility's common
19 stock, the most junior and riskiest of its securities, is
20 considerably higher than the yield on the utility's long-
21 term debt.
22 Q. Is the cost of equity observable in the
23 capital markets?

A. No. Unlike debt capital, there is no contractually guaranteed return on common equity capital since shareholders are the residual owners of the utility. Because it is unobservable, the cost of equity for a particular utility must be estimated by analyzing information about capital market conditions generally, assessing the relative risks of the company specifically, and employing various quantitative methods that focus on investors' current required rates of return. These various quantitative methods typically attempt to infer investors' required rates of return from stock prices, interest rates, or other capital market data.

Q. Did you rely on a single method to estimate the cost of equity for Idaho Power?

A. No. In my opinion, no single method or model should be used to estimate a utility's cost of equity because no single approach can be regarded as wholly reliable. As the Federal Communications Commission recognized:

> Equity prices are established in highly volatile and uncertain capital markets... Different forecasting methodologies compete with each other for eminence, only to be superceded by other methodologies as conditions change... In these circumstances, we should not restrict ourselves to one methodology, or even a series of methodologies, that would be applied mechanically.

1 Instead, we conclude that we should adopt a more
2 accommodating and flexible position.[46]

3 Therefore, I considered the results of both the DCF model
4 and risk premium methods to estimate the cost of equity. In
5 addition, I also evaluated a fair rate of return using a
6 comparable earnings approach based on investors' current
7 expectations in the capital markets. In my opinion,
8 comparing estimates produced by one method with those
9 produced by other approaches ensures that the estimates of
10 the cost of equity pass fundamental tests of reasonableness
11 and economic logic.

12 Q. Which companies did you reference in applying
13 the risk premium and DCF approaches to estimate the cost of
14 equity?

15 A. As explained in my Additional Direct
16 testimony, my quantitative analyses of investors' required
17 rate of return focused on a group of ten publicly traded
18 utilities included by Value Line in their Electric Utilities
19 (West) Industry group, all of which pay common dividends and
20 have investment grade credit ratings.

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[46] Federal Communications Commission, Report and Order 42-43, CC Docket No. 92-133 (1995).

1 Q. Based on the results of your analyses, what
2 was your conclusion regarding a fair rate of return on
3 equity for the companies in the proxy group?
4 A. After incorporating an adjustment for
5 flotation costs, I concluded that a fair rate of return on
6 equity for the proxy group of utilities is in the 11.0% to
7 12.0% range, with a midpoint of 11.5%.

8 **B. Results of Quantitative Analyses**

9 Q. Briefly describe your risk premium methods.
10 A. The details of my risk premium analyses are
11 presented in my Additional Direct testimony. As explained
12 there, the risk premium method involves determining the
13 additional return above the yield on bonds that investors
14 require for bearing the higher risks of common stock. This
15 equity risk premium is then added to the current yield on
16 bonds to estimate the cost of equity. My applications of
17 the risk premium method provide alternative approaches to
18 measure equity risk premiums that focused specifically on
19 data for electric utilities and employed alternative
20 estimates of investors' required rates of return.
21 My risk premium analyses were based on three widely
22 accepted and commonly applied approaches -- (1) surveys of
23 previously authorized rates of return on common equity, (2)

1 realized rates of return, and (3) alternative applications
2 of the Capital Asset Pricing Model ("CAPM").
3 Q. Is it appropriate to consider anticipated
4 capital market changes in applying risk premium methods?
5 A. Yes. As detailed in my Additional Direct
6 testimony, there is widespread consensus that interest rates
7 will increase materially as the economy continues to
8 strengthen, with the Federal Reserve's recent actions
9 indicative of tighter credit conditions and higher interest
10 rates in the years ahead. As a result, current bond yields
11 are likely to understate capital market requirements at the
12 time the outcome of this proceeding becomes effective.
13 Accordingly, in addition to the use of current bond
14 yields, I also applied the alternative risk premium methods
15 using forecasted bond yields for 2006 developed based on an
16 average of the projections published by GlobalInsight, the
17 Energy Information Administration, and Blue Chip Financial
18 Forecasts.[47]
19 Q. What were the results of your risk premium
20 analyses for the proxy group of utilities?

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[47] An analogous approach was adopted by the staff of the Florida Public Service Commission in a May 20, 2004 *Memorandum* in Docket No. 040006-WS and in the testimony of staff witness Andrew L. Maurey in Docket No. 000824-EI (Jan. 2002).

1 A. As detailed in my Additional Direct
2 testimony, my risk premium analyses implied the following
3 cost of equity estimates:

Risk Premium Approach	Cost of Equity Estimate
Authorized Returns	
Current Yield	10.7%
Projected Yield	11.4%
Realized Rates of Return	
Current Yield	9.8%
Projected Yield	11.0%
CAPM - Forward-looking	
Current Yield	12.5%
Projected Yield	12.6%
CAPM - Historical	
Current Yield	10.9%
Projected Yield	11.9%

4 Q. What cost of equity was indicated by your DCF
5 analyses for the proxy group of western utilities?
6 A. Dividend yields for the nine firms in the
7 utility proxy group ranged from 2.2% to 4.6%, and averaged
8 3.5%. Combining this dividend yield with the 5.5% growth
9 rate indicated for the proxy group implied a DCF cost of
10 equity of 9.0%.
11 Q. Do you believe this DCF result represents a
12 reasonable estimate of the cost of equity for the proxy
13 group or Idaho Power?
14 A. No. As I noted earlier, because the cost of
15 equity is unobservable, no single method should be viewed in

1 isolation. While the DCF model has been routinely relied on
2 in regulatory proceedings as one guide to investors'
3 required return, it is a blunt tool that should never be
4 used exclusively, and regulators have customarily considered
5 the results of alternative approaches in determining allowed
6 returns. The need to consider alternative methods is
7 especially important where the results of one approach
8 deviate significantly from cost of equity estimates produced
9 by other applications. Indeed, as discussed earlier, the
10 results of alternative risk premium methods suggest a cost
11 of equity far in excess of this single DCF value.
12 Moreover, as discussed in my Additional Direct
13 testimony, the short-term projected growth rates typically
14 used to apply the DCF model may be colored by lingering
15 uncertainties regarding the near-term direction of the
16 economy in general and the spate of challenges recently
17 faced in the electric power industry specifically. This
18 short-term "hangover" is exemplified by Value Line, which
19 has assigned its Utilities sector the lowest ranking of all
20 10 sectors it covers for year-ahead stock price
21 performance,[48] while noting that "[t]he electric utility
22 industry carries a below-average industry Timeliness

[48] The Value Line Investment Survey, *Selection & Opinion* (July 29, 2005) at 1606.

1 rank."[49] As a result of this cautious near-term outlook,
2 DCF growth rates do not necessarily capture investors' long-
3 term expectations for the industry, and the resulting cost
4 of equity estimates will be downward biased.
5 Accordingly, it would be unreasonable to establish
6 an ROE based on this single DCF result, especially
7 considering my earlier discussion of Idaho Power's
8 investment risks and the importance of maintaining the
9 Company's ability to attract capital.
10 Q. What other analyses did you conduct to
11 estimate the cost of equity?
12 A. As I noted earlier, I also evaluated the cost
13 of equity using the comparable earnings method. Reference
14 to rates of return available from alternative investments of
15 comparable risk can provide an important benchmark in
16 assessing the return necessary to assure confidence in the
17 financial integrity of a firm and its ability to attract
18 capital. This comparable earnings approach is consistent
19 with the economic underpinnings for a fair rate of return
20 established by the Supreme Court. Moreover, it avoids the
21 complexities and limitations of capital market methods and

[49] The Value Line Investment Survey (July 1, 2005) at 695.

1 instead focuses on the returns earned on book equity, which
2 are readily available to investors.
3 Q. What rates of return on equity are indicated
4 for utilities based on this approach?
5 A. With respect to expectations for electric
6 utilities specifically, the most recent edition of Value
7 Line reports that its analysts anticipate an average rate of
8 return on common equity for the electric utility industry of
9 10.5% in 2005 and 2006, increasing to 11.0% over its three-
10 to-five year forecast horizon.[50] Meanwhile, Value Line
11 expects that natural gas distribution utilities will earn an
12 average rate of return on common equity of 12.0% in 2005 and
13 2006, and 12.5% for 2008-2010.[51]
14 Q. Can the comparable earnings method be applied
15 to other firms of similar risk?
16 A. Yes. Under the regulatory standards
17 established by *Hope* and *Bluefield*, the salient criteria in
18 establishing a meaningful benchmark to evaluate a fair rate
19 of return is relative risk, not the particular business
20 activity or degree of regulation. Utilities must compete
21 for capital, not just against firms in their own industry,
22 but with other investment opportunities of comparable risk.

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[50] The Value Line Investment Survey (Sep. 2, 2005) at 156.
[51] The Value Line Investment Survey (Sep. 16, 2005) at 459.

1 Consistent with this accepted regulatory standard, I also
2 applied the comparable earnings approach based on a
3 reference group of companies in the unregulated sector of
4 the economy.
5 The average Value Line Safety Ranking for the firms
6 in the proxy group is "2", with beta values for the ten
7 electric utilities ranging from 0.70 to 1.05. Accordingly,
8 my reference group was composed of those U.S. companies
9 followed by Value Line that 1) pay common dividends, 2) have
10 a Safety Rank of "2", and 3) have beta values between 0.70
11 and 1.05. Value Line's projections indicate that its
12 analysts expect that rates of return on shareholders' equity
13 for the resulting group of 151 firms will average 15.7%,
14 with the median being 14.0%.[52]
15 Q. What return on equity is indicated by the
16 results of the comparable earnings approach?
17 A. Based on the results discussed above, I
18 concluded that the comparable earnings approach implies a
19 fair rate of return on equity in the range of 11.0% to
20 12.0%.

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[52] www.valueline.com (Retrieved Oct. 11, 2005).

1 **C. Proxy Group Cost of Equity**

2 Q. What did you conclude with respect to the
3 cost of equity for the proxy group of utilities?

4 A. In light of anticipated capital market trends
5 and the recent challenges experienced in the utility
6 industry, caution should be exercised in interpreting the
7 results of DCF and risk premium applications. As noted
8 earlier, the single DCF result is out of line with the
9 preponderance of estimates produced by the risk premium and
10 comparable earnings approaches and should not be viewed in
11 isolation, especially considering the potential for downward
12 bias when DCF growth rates do not capture investors' long-
13 term expectations. Moreover, in light of accelerating
14 economic growth and expectations for higher interest rates,
15 risk premium estimates based on projected capital market
16 conditions should receive more weight.

17 Accordingly, based on the results of my quantitative
18 analyses, and my assessment of the relative strengths and
19 weaknesses inherent in each method, I concluded that the
20 cost of equity for the utility proxy group is in the 10.8%
21 to 11.8% range.

22 Q. What other considerations are relevant in
23 setting the return on equity for a utility?

1 A. The common equity used to finance the
2 investment in utility assets is provided from either the
3 sale of stock in the capital markets or from retained
4 earnings not paid out as dividends. When equity is raised
5 through the sale of common stock, there are costs associated
6 with "floating" the new equity securities. These flotation
7 costs include services such as legal, accounting, and
8 printing, as well as the fees and discounts paid to
9 compensate brokers for selling the stock to the public.
10 Also, some argue that the "market pressure" from the
11 additional supply of common stock and other market factors
12 may further reduce the amount of funds a utility nets when
13 it issues common equity.
14 Q. Is there an established mechanism for a
15 utility to recognize equity issuance costs?
16 A. No. While debt flotation costs are recorded
17 on the books of the utility, amortized over the life of the
18 issue, and thus increase the effective cost of debt capital,
19 there is no similar accounting treatment to ensure that
20 equity flotation costs are recorded and ultimately
21 recognized. Alternatively, no rate of return is authorized
22 on flotation costs necessarily incurred to obtain a portion
23 of the equity capital used to finance plant. In other words,
24 equity flotation costs are not included in a utility's rate

base because neither that portion of the gross proceeds from the sale of common stock used to pay flotation costs is available to invest in plant and equipment, nor are flotation costs capitalized as an intangible asset. Unless some provision is made to recognize these issuance costs, a utility's revenue requirements will not fully reflect all of the costs incurred for the use of investors' funds. Because there is no accounting convention to accumulate the flotation costs associated with equity issues, they must be accounted for indirectly, with an upward adjustment to the cost of equity being the most logical mechanism.

Q. What is the magnitude of the adjustment to the "bare bones" cost of equity to account for issuance costs?

A. There are a number of ways in which a flotation cost adjustment can be calculated, and the adjustment can range from just a few basis points to more than a full percent. One of the most common methods used to account for flotation costs in regulatory proceedings is to apply an average flotation-cost percentage to a utility's dividend yield. Based on a review of the finance literature, *Regulatory Finance: Utilities' Cost of Capital* concluded:

> The flotation cost allowance requires an estimated adjustment to the return on equity of approximately 5% to 10%, depending on the size and risk of the issue.[53]

Alternatively, a study of recent data from Morgan Stanley regarding issuance costs associated with utility common stock issuances suggests an average flotation cost percentage of 3.6%.[54] Applying these expense percentages to a representative dividend yield for a utility of 3.5% implies a flotation cost adjustment on the order of 13 to 35 basis points.

Q. What then is your conclusion regarding a fair rate of return on equity for the companies in your proxy group of western utilities?

A. After incorporating an adjustment for flotation costs of 20 basis points to my "bare bones" cost of equity range, I concluded that a fair rate of return on equity for the proxy group of utilities is in the 11.0% to 12.0% range, with a midpoint of 11.5%.

IV. RETURN ON EQUITY FOR IDAHO POWER

Q. What is the purpose of this section?

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[53] Roger A. Morin, *Regulatory Finance: Utilities' Cost of Capital*, 1994, at 166.

[54] *Application of Yankee Gas Services Company for a Rate Increase*, DPUC Docket No. 04-06-01, Direct Testimony of George J. Eckenroth (Jul. 2, 2004) at Exhibit GJE-11.1. Updating the results presented by Mr. Eckenroth through April 2005 also resulted in an average flotation cost percentage of 3.6%.

A. In addition to presenting the conclusions of my evaluation of a fair rate of return on equity for Idaho Power, this section also discusses the relationship between ROE and preservation of a utility's financial integrity and the sustained ability to attract capital under reasonable terms.

A. Implications for Financial Integrity

Q. Why is it important to allow Idaho Power an adequate rate of return on equity?

A. Given the social and economic importance of the utility industry, it is essential to maintain reliable and economical service to all consumers. While Idaho Power remains committed to deliver reliable service, a utility's ability to fulfill its mandate can be compromised if it lacks the necessary financial wherewithal. As S&P noted, Idaho Power faces "significant exposure to hydrological variations in the Snake River and significant capital expenditure requirements for new generation and hydro relicensing."[55] Coupled with the ongoing potential for energy market volatility, this poses a number of potential challenges that might require the relatively swift

[55] Standard & Poor's Corporation, "IDACORP and Unit Ratings Lowered, Removed From CreditWatch Negative," *RatingsDirect* (Nov. 29, 2004).

1 commitment of significant capital resources in order to
2 maintain the high level of service that customers have come
3 to expect.
4 Events in the western U.S. provide a dramatic
5 illustration of just how swiftly unforeseen circumstances
6 can lead to deterioration in a utility's financial
7 condition, and stakeholders have discovered first hand how
8 difficult and complex it can be to remedy the situation
9 after the fact. For a utility with an obligation to provide
10 reliable service, investors' increased reticence to supply
11 additional capital during times of crisis highlights the
12 necessity of preserving the flexibility necessary to
13 overcome periods of adverse capital market conditions.
14 Q. What role does regulation play in ensuring
15 Idaho Power's access to capital?
16 A. Considering investors' heightened awareness
17 of the risks associated with the utility industry and the
18 damage that results when a utility's financial flexibility
19 is compromised, supportive regulation remains crucial to
20 Idaho Power's access to capital. Investors recognize that
21 constructive regulation is a key ingredient in supporting
22 utility credit ratings and financial integrity, particularly
23 during times of adverse conditions. S&P noted that:

> When examining the quality of regulation, Standard & Poor's factors in what level of support the utility might get in times of distress, when its needs are most acute.[56]

S&P went on to note the importance of financial flexibility, especially considering the capital markets' ability to constrict access to capital when investors' confidence is compromised. As S&P concluded, "[d]ecisions by public service commissions can profoundly affect utilities' credit quality."[57]

Investors recognize that regulation has its own risks. Considering the magnitude of the events that have transpired since the third quarter of 2000, investors' sensitivity to market and regulatory uncertainties has increased dramatically. The recent decision of S&P and Fitch to downgrade Central Vermont from triple-B to below investment grade highlights the importance of constructive regulation. In explaining its rationale, S&P and Fitch cited an unfavorable rate order by the Vermont Public Service Board. S&P concluded that:

> The rate order represents an adverse shift in the company's regulatory environment, which heightens its business risk for the foreseeable future. ... It also limits the company's ability to generate adequate and stable cash flows over the

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[56] Standard & Poor's Corporation, "Regulation and Credit Quality in the U.S. Utility Sector," *RatingsDirect* (Jan. 30, 2003).
[57] *Id.*

> foreseeable future. To be considered highly creditworthy, a utility with a marginal financial profile must operate in a regulatory environment that provides for financial stability.[58]

Business Wire reported to investors that Central Vermont "will now have to provide cash collateral for some power supply arrangements" and pay "increased financing costs for debt," with the end result being "higher customer costs."[59]

Q. Has the investment community also recognized that regulatory support is a crucial determinant of Idaho Power's credit standing?

A. Yes. All of the major bond rating agencies have specifically noted that constructive regulation will be a deciding factor in establishing the future course of Idaho Power's financial strength. For example, Moody's noted the need for "additional support" from the IPUC as Idaho Power adds new generation and transmission infrastructure to meet growth and ensure reliability.[60] Similarly, Fitch noted the need for over $600 million in capital expenditures for additional generating capacity and infrastructure upgrades, necessitated in part by continued growth and "incremental

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[58] "S&P Downgrades CVPS Corporate Credit Rating," *Business Wire* (Jun. 14, 2005).
[59] *Id.*
[60] Moody's Investors Service, "Ratings Action: IDACORP, Inc.," *Global Credit Research* (Dec. 3, 2004).

1 stress on thermal resources as a result of poor water
2 conditions," concluding that:

3 A lack of regulatory support, combined with
4 continuing poor hydro conditions, could lead to
5 further deterioration in [Idaho Power's]
6 creditworthiness.[61]

7 Q. What danger does an inadequate rate of return
8 pose to Idaho Power?

9 A. Given the recent decline in Idaho Power's
10 corporate credit rating, the perception of a lack of
11 regulatory support would almost certainly lead to further
12 downgrades. At the same time, Idaho Power's plans include
13 significant plant investment to ensure that the energy needs
14 of its service territory are met in a reliable and cost-
15 effective manner. While providing the infrastructure
16 necessary to meet the energy needs of customers is certainly
17 desirable, it imposes additional financial responsibilities
18 on Idaho Power. To continue to meet these challenges
19 successfully and economically, it is crucial that Idaho
20 Power receive adequate support to maintain its credit
21 standing.

22 Q. Do customers also benefit by enhancing the
23 utility's financial flexibility?

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[61] Fitch Ratings, Ltd., "Idaho Power Company," *Global Power/North America Credit Analysis* (Feb. 18, 2005) at 3.

A. Yes. While providing an ROE that is sufficient to maintain Idaho Power's ability to attract capital, even under duress, is consistent with the economic requirements embodied in the Supreme Court's *Hope* and *Bluefield* decisions, it is also in ratepayers' best interests. Ultimately, it is customers and the service area economy that enjoy the benefits that come from ensuring that the utility has the financial wherewithal to take whatever actions are required to ensure a reliable energy supply. By the same token, ratepayers also bear a significant burden when the ability of the utility to attract necessary capital is impaired and service quality is compromised.

B. Changes Since Case No. IPC-E-03-13

Q. Do circumstances since Case No. IPC-E-03-13 support an increase in Idaho Power's ROE?

A. Yes. In its order in Idaho Power's last rate proceeding, the IPUC clearly expressed its goal of supporting Idaho Power's efforts to maintain its financial strength:

> [T]his Commission acknowledges its desire to maintain Idaho Power as a financially viable utility with credit ratings at or above the current level.[62]

[62] IPUC Order No. 29505, Case No. IPC-E-03-13 (May 25, 2004) at 43.

1 Considering the perceptions of the investment community,
2 which are instrumental in any evaluation of Idaho Power's
3 creditworthiness, a higher ROE will be required if the
4 Company is to regain its former credit ratings, consistent
5 with the stated objectives in the IPUC's last rate order.
6 In fact, regulatory support, in the form of a higher allowed
7 return on equity, may be necessary just to stabilize ratings
8 at current levels. S&P noted that "supportive future rate
9 case rulings by the IPUC" would be required "to support the
10 rating at the current level."[63]
11 Apart from the need to meet the IPUC's objective of
12 stabilizing Idaho Power's credit standing, a higher ROE is
13 also warranted to compensate for greater investment risks.
14 The fact that Idaho Power's credit ratings have been lowered
15 by all of the major ratings agencies supports a finding that
16 its risks and required rate of return have moved higher
17 since the Company's last rate proceeding. At the same time,
18 the importance of enhancing Idaho Power's creditworthiness
19 has increased as planned system expansions and debt
20 refinancing will require greater access to capital markets
21 than at any time in the recent past.

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[63] Standard & Poor's Corporation, "IDACORP, Inc.," *RatingsDirect* (Sep. 20, 2005) at 2.

1 Meanwhile, anticipated capital market trends also
2 support a higher ROE for Idaho Power in this proceeding.
3 Since the time of the IPUC's decision in Case No. IPC-E-03-
4 13, utility bond yields have been relatively stable,
5 although spot yields have recently increased.[64] As
6 discussed earlier, however, long-term interest rates are
7 expected to increase during 2006 and into the foreseeable
8 future, with the projections of widely recognized sources
9 providing independent evidence of increasing capital costs.
10 Thus, capital market conditions over the period when rates
11 established in this proceeding will be in effect also
12 suggest that the ROE has increased since Case No. IPC-E-03-
13 13.
14 Uncertainties associated with Idaho Power's
15 operations - including the impact of prolonged drought on
16 hydroelectric generation, uncertainties and cash
17 requirements associated with relicensing, renewed focus on
18 regulatory uncertainties, exposure to potential energy
19 market volatility, and the need for significant capital
20 investment - have become increasingly apparent to investors.
21 Here again, the trends since the IPUC's decision in Case No.

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[64] Moody's Investors Service reported an average yields on triple-B public utility bonds of 5.88% and 5.80% for May and August 2005, respectively, with the yield on October 10, 2005 being 5.96%.

1 IPC-E-03-13 would argue for an increase to Idaho Power's
2 allowed return.

3 **C. Conclusions**

4 Q. What is your conclusion regarding a fair rate
5 of return on equity range for Idaho Power?
6 A. Based on the capital market research
7 presented earlier and the economic requirements discussed
8 above, it is my conclusion that a return on equity in the
9 range of 11.0% to 12.0% represents a reasonable estimate of
10 investors' required rate of return for Idaho Power in
11 today's capital markets.
12 In evaluating the rate of return for Idaho Power, it
13 is important to consider investors' continued focus on the
14 unsettled conditions in restructured wholesale energy
15 markets, the Company's ongoing reliance on these markets to
16 purchase a portion of its energy supply, as well as other
17 risks associated with the utility industry, such as
18 heightened exposure to regulatory uncertainties.
19 My recommended ROE range is further supported by the
20 fact that investors are likely to anticipate increases in
21 utility bond yields going forward. Moreover, an ROE in the
22 11.0% to 12.0% range is reasonable at this critical
23 juncture, given the importance of supporting the financial

1 capability of Idaho Power as it seeks to maintain its credit
2 standing while raising the capital necessary to develop and
3 enhance utility infrastructure. The cost of providing Idaho
4 Power an adequate return is small relative to the potential
5 benefits that a strong utility can have in providing
6 reliable service. Considering investors' heightened
7 awareness of the risks associated with the utility industry
8 and the damage that results when a utility's financial
9 flexibility is compromised, supportive regulation is perhaps
10 more crucial now than at any time in the past.
11 Q. Does this conclude your pre-filed direct
12 testimony?
13 A. Yes.
14 Q. Are you sponsoring additional testimony that
15 contains the details underlying your quantitative analyses
16 of the cost of equity?
17 A. Yes, I am.

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-05-28

IDAHO POWER COMPANY

ADDITIONAL DIRECT TESTIMONY

OF

WILLIAM E.AVERA

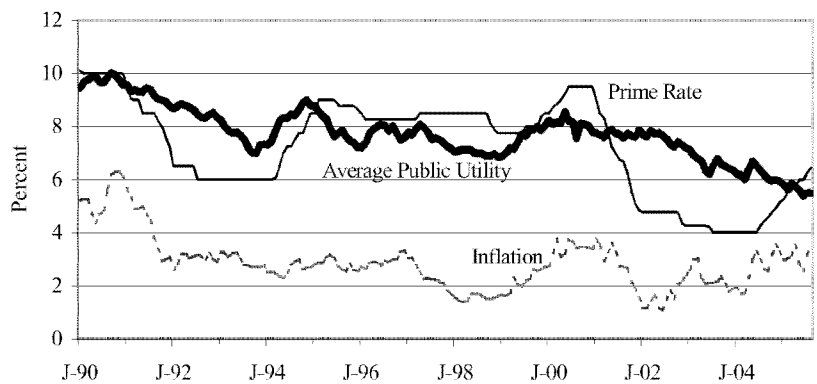
I. INTRODUCTION

1 Q. What is the purpose of your Additional
2 Direct testimony?
3 A. The purpose of this testimony is to present
4 the details underlying my quantitative analyses of the cost
5 of equity for the proxy group of electric utilities.
6 First, I review general conditions in the capital markets
7 and general economy. Next, I examine the concept of the
8 cost of equity, along with the risk-return tradeoff
9 principle fundamental to capital markets. Finally, I
10 describe risk premium and discounted cash flow ("DCF")
11 analyses conducted to estimate the cost of equity for the
12 reference group of electric utilities.

A. Capital Markets and Economy

13 Q. What has been the pattern of interest rates
14 over the last decade?
15 A. Average long-term public utility bond rates,
16 the monthly average prime rate, and inflation as measured
17 by the consumer price index since 1990 are plotted in the
18 graph below. After rising to approximately 10% in mid-
19 1990, the average yield on long-term public utility bonds

1 generally fell as economic conditions weakened in the
2 aftermath of the 1991 Gulf war, with rates dipping below 7%
3 in late 1993. Yields subsequently rose again in 1994,
4 before beginning a general decline, with investors
5 requiring approximately 5.5% from average public utility
6 bonds in August 2005:



7 Q. Are investors likely to anticipate any
8 substantial decline in interest rates going forward?
9 A. No. Since early 2001, a great deal of
10 attention has been focused on the actions of the Federal
11 Reserve Board ("Fed") as it has moved successively to lower
12 short-term interest rates in response to weakness in the
13 United States economy. But while interest rates are
14 currently at relatively low levels, investors are unlikely
15 to expect any further significant declines going forward.
16 Indeed, on September 20, 2005 the Fed raised interest rates

for the eleventh time since June 2004 and signaled to investors that higher rates were likely in the future. The latest quarter-point increase raised the discount rate to 3.75%, or over three times the 46-year low of 1.00% in effect when the Fed began its credit-tightening campaign in 2004. As Value Line noted,[1] the general expectation is that interest rates will continue to rise with strengthening economic growth. The Wall Street Journal reported that, with growing inflationary concerns, investors are concerned that the Fed will adopt a more aggressive stance:

> [S]igns have emerged that inflation may be working itself into the economy. That would be bad news for stocks, notably because it likely would prompt the Federal Reserve to try to cool the economy by pushing interest rates higher, raising borrowing costs for businesses and consumers alike. ... Particularly worrisome to investors was the sight this week of the presidents of three regional Federal Reserve banks publicly warning the Fed is concerned about inflation. The Fed can't "let the inflation virus infect the blood supply and poison the system," said Dallas Fed President Richard Fisher yesterday. Investors took that to mean the Fed, which has already boosted short-term interest rates 11 times in the past 15 months, could continue to do so for some time.[2]

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[1] The Value Line Investment Survey, *Selection & Opinion* (Jun. 24, 2005) at 1659.

[2] Browning, E.S., "Inflation Worries Send Shivers Through Markets - Investors See Warning Signs Despite Falling Oil Prices; Watching Earnings Season," The Wall Street Journal (Oct. 7, 2005) at A1.

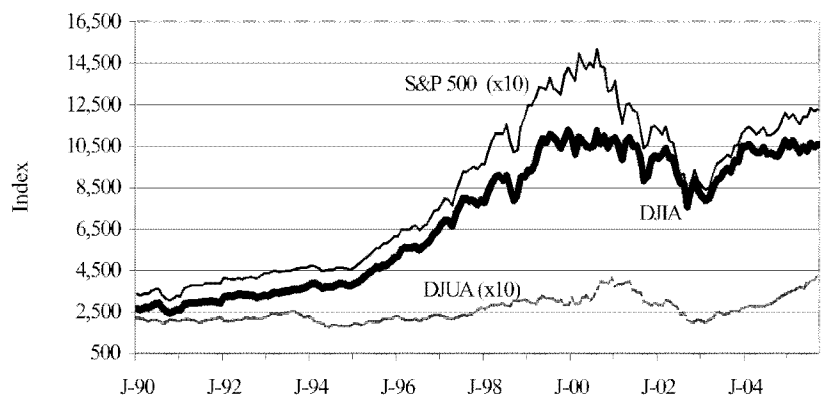
1 Consistent with the general expectations that these
2 actions will also translate into higher long-term bond
3 yields, the most recent forecast of GlobalInsight, a widely
4 referenced forecasting service, calls for double-A public
5 utility bond yields to reach 6.41% in 2006, averaging 6.99%
6 over the next five years.[3] Meanwhile, the Energy
7 Information Administration ("EIA"), a statistical agency of
8 the DOE, anticipates that the double-A public utility bond
9 yield will average 7.16% over the 2006-2010 period.[4] The
10 September 1, 2005 edition of Blue Chip Financial Forecasts
11 ("Blue Chip") also anticipates that bond yields will rise
12 significantly over the coming year.[5]

13 Q. How has the market for common equity capital
14 performed?

15 A. Between 1990 and early 2000 stock prices
16 pushed steadily higher as the longest bull market in United
17 States history continued unabated. While the S&P 500 had
18 increased over four times in value by August 2000, mounting
19 concerns regarding prospects for future growth,
20 particularly for firms in the high technology sector,

[3] GlobalInsight, "The U.S. Economy, The 25-Year Focus", Table 33 (First Quarter 2005).
[4] Energy Information Administration, "Annual Energy Outlook 2005", Table 19.
[5] Blue Chip Financial Forecasts (Sep. 1, 2005) at 2.

1 pushed equity prices lower, in some cases precipitously.
2 While common stock prices have recovered strongly from
3 their lows, the market remains volatile, with share values
4 routinely changing in full percentage points during a
5 single day's trading. The graph below plots the
6 performances of the Dow-Jones Industrial Average, the S&P
7 500, and the Dow Jones Utility Average since 1990 (the
8 latter two indices were scaled for comparability):



9 Q. What is the outlook for the United States
10 economy?
11 A. While the economic picture has brightened
12 significantly since the downturn that began in 2001, growth
13 in gross domestic product slowed to 3.2% in the second
14 quarter of 2005. Uncertainties over the durability and
15 pace of economic growth continue to be impacted by

1 overhanging government and trade deficits and higher energy
2 prices, which have been exacerbated by the fallout from the
3 natural disasters experienced in the Gulf Coast region.
4 Continued conflict and instability in Iraq and the ongoing
5 threat of terrorism also undermine consumer confidence and
6 contribute to global economic uncertainty. These factors
7 cause the outlook to remain tenuous, with persistent stock
8 and bond price volatility providing tangible evidence of
9 the uncertainties faced by the United States economy.
10 Q. How do these economic uncertainties affect
11 utilities?
12 A. Uncertainties over the extent and durability
13 of the economic recovery have combined to heighten the
14 risks faced by utilities. Stagnant economic growth would
15 undoubtedly mean flat sales, while the potential for higher
16 inflation and interest rates would place additional
17 pressure on the adequacy of existing service rates.
18 Meanwhile, the aftermath of hurricanes Katrina and Rita,
19 coupled with continued conflict and instability in the
20 Middle East, intensifies concerns over prolonged volatility
21 in oil and gas prices. While the economy may ultimately
22 return to a path of steady growth and the volatility in the

1 capital and energy markets may abate, the underlying
2 weaknesses now present cause considerable uncertainties to
3 persist, which increase the risks faced by the utility
4 industry.

B. Risk-Return Tradeoff Principle

5 Q. What fundamental economic principle under-
6 lies a determination of the cost of equity?
7 A. Unlike debt capital, there is no
8 contractually guaranteed return on common equity capital
9 since shareholders are the residual owners of the utility.
10 Nonetheless, common equity investors still require a return
11 on their investment, with the cost of equity being the
12 minimum "rent" that must be paid for the use of their
13 money. This cost of equity typically serves as the
14 starting point for determining a fair rate of return on
15 common equity.
16 The cost of equity concept is predicated on the
17 notion that investors are risk averse, and will willingly
18 bear additional risk only if they expect compensation for
19 doing so. In capital markets where relatively risk-free
20 assets are available (*e.g.*, U.S. Treasury securities)
21 investors can be induced to hold more risky assets only if

they are offered a premium, or additional return, above the rate of return on a risk-free asset. Since all assets compete with each other for investors' funds, more risky assets must yield a higher expected rate of return than less risky assets in order for investors to be willing to hold them.

Given this risk-return tradeoff, the required rate of return (k) from an asset (i) can be generally expressed as:

$$k_i = R_f + RP_i$$

where: R_f = Risk-free rate of return; and

RP_i = Risk premium required to hold risky asset i.

Thus, the required rate of return for a particular asset at any point in time is a function of: 1) the yield on risk-free assets, and 2) its relative risk, with investors demanding correspondingly larger risk premiums for assets bearing greater risk.

Q. Does the risk-return tradeoff principle actually operate in the capital markets?

A. Yes. The risk-return tradeoff is readily observable in certain segments of the capital markets where required rates of return can be directly inferred from

1 market data and generally accepted measures of risk exist.
2 Bond yields, for example, reflect investors' expected rates
3 of return, and bond ratings measure the risk of individual
4 bond issues. The observed yields on government securities,
5 which are considered free of default risk, and bonds of
6 various rating categories demonstrate that the risk-return
7 tradeoff does, in fact, exist in the capital markets.

8 Q. Does the risk-return tradeoff observed with
9 fixed income securities extend to common stocks and other
10 assets?

11 A. It is generally accepted that the risk-
12 return tradeoff evidenced with long-term debt extends to
13 all assets. Documenting the risk-return tradeoff for
14 assets other than fixed income securities, however, is
15 complicated by two factors. First, there is no standard
16 measure of risk applicable to all assets. Second, for most
17 assets - including common stock - required rates of return
18 cannot be directly observed. Nevertheless, it is a
19 fundamental tenet that investors exhibit risk aversion in
20 deciding whether or not to hold common stocks and other
21 assets, just as when choosing among fixed income
22 securities. This has been supported and demonstrated by

1 considerable empirical research in the field of finance and
2 is confirmed by reference to historical earned rates of
3 return, with realized rates of return on common stocks
4 exceeding those on government and corporate bonds over the
5 long-term.

6 Q. Is this risk-return tradeoff limited to
7 differences between firms?

8 A. No. The risk-return tradeoff principle
9 applies not only to investments in different firms, but
10 also to different securities issued by the same firm.
11 Debt, preferred stock, and common equity vary considerably
12 in risk because they have different characteristics and
13 priorities.

14 When investors loan money in the form of debt (*e.g.*,
15 long-term bonds), they enter into a contract whereby the
16 utility agrees to pay the bondholders a specified amount of
17 interest and to repay the principal of the loan in full.
18 The bondholders have a senior claim on available cash flow
19 for these payments, and if the utility fails to make them,
20 they may force it into bankruptcy and liquidation for
21 settlement of unpaid claims. Similarly, when a utility
22 sells investors preferred stock, the utility promises to

1 pay preferred stockholders specified dividends and,
2 typically, to retire the preferred stock on a predetermined
3 schedule. While the rights of preferred stockholders to
4 available cash flow for these payments are junior to
5 creditors, and preferred stockholders cannot compel
6 bankruptcy, their claims are senior to those of common
7 shareholders.
8 The last investors in line are common shareholders.
9 They only receive the cash flow, if any, that remains after
10 all other claimants – employees, suppliers, governments,
11 lenders, and preferred stockholders - have been paid. As a
12 result, the rate of return that investors require from a
13 utility's common stock, the most junior and riskiest of its
14 securities, is considerably higher than the yield on the
15 utility's long-term debt or preferred stock, which have
16 more certain, senior claims.
17 Q. What does the above discussion imply with
18 respect to estimating the cost of equity?
19 A. Although the cost of equity cannot be
20 observed directly, it is a function of the returns
21 available from other investment alternatives and the risks
22 to which the equity capital is exposed. Because it is

1 unobservable, the cost of equity for a particular utility
2 must be estimated by analyzing information about capital
3 market conditions generally, assessing the relative risks
4 of the company specifically, and employing various
5 quantitative methods that focus on investors' required
6 rates of return. These various quantitative methods
7 typically attempt to infer investors' required rates of
8 return from stock prices, interest rates, or other capital
9 market data.

10 Q. How did you implement these quantitative
11 methods to estimate the cost of equity for Idaho Power?
12 A. In estimating the cost of equity,
13 quantitative methods are typically applied to publicly
14 traded firms engaged in similar business activities. In
15 order to reflect the risks and prospects associated with
16 Idaho Power's jurisdictional utility operations, my
17 analyses focused on a reference group of other electric
18 utilities composed of those companies included by Value
19 Line in their Electric Utilities (West) Industry group.
20 Excluded from my analyses were five firms that either do
21 not pay common dividends or were rated below investment
22 grade by S&P.

1 Given that these ten utilities are all engaged in
2 utility operations in the western region of the U.S.,
3 investors are likely to regard this group as facing similar
4 market conditions and having comparable risks and
5 prospects. The Supreme Court recognized the relevance of
6 geographical location in *Bluefield,* noting that utilities
7 are entitled to earn a return equal to those being made by
8 firms of comparable risk "in the same general part of the
9 country."[6] Indeed, there are important factors
10 distinguishing western utilities from those located in
11 other regions, including customer density and the
12 complexities associated with greater reliance on
13 hydroelectric generation. As noted in my Direct testimony,
14 the ongoing uncertainties associated with hydroelectric
15 generation and western power markets are important
16 considerations in evaluating investors' required rate of
17 return for Idaho Power.

[6] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n,* 262 U.S. 679 (1923).

1 Q. What other considerations support the use of
2 a proxy group in estimating the cost of equity for Idaho
3 Power?
4 A. Apart from recognizing the inherent risks
5 and prospects for a utility operating in the west,
6 reference to a proxy group of utilities is essential to
7 insulate against vagaries that can result when the
8 stochastic process involved in estimating the cost of
9 equity is applied to a single company. The cost of equity
10 is inherently unobservable and can only be inferred
11 indirectly by reference to available capital market data.
12 To the extent that the data does not capture investors'
13 actual expectations, the resulting cost of equity estimates
14 will be biased and fail to reflect the required rate of
15 return. As the FERC noted in its July 3, 2003 *Order on*
16 *Initial Decision* in Docket No. RP00-107-000, even using a
17 limited group of companies increases the potential for
18 error:

19 Both Staff and Williston agreed that a proxy
20 group of only three companies presented
21 problems because "a single company will have a
22 magnified influence on the group results." It
23 was with those changing market dynamics in mind
24 that witnesses of both Staff and Williston

1 proposed to expand the group of proxy companies
2 to determine a zone of reasonableness.[7]

3 A proxy group composed of western utilities is consistent
4 not only with the shared circumstances of energy markets in
5 the west, but also with the need to ensure against the
6 potential that a single cost of equity estimate may not
7 reflect investors' required rate of return.

8 Q. Why did you exclude firms that do not pay
9 common dividends or have below investment grade bond
10 ratings?

11 A. As discussed subsequently, under the DCF
12 approach, observable stock prices are a function of the
13 cash flows that investors' expected to receive, discounted
14 at their required rate of return. Because dividend
15 payments are a key parameter required to apply the DCF
16 method, this hinders application of the DCF model to firms
17 that do not pay common dividends. Meanwhile, the financial
18 stress and lack of stability that accompanies below
19 investment grade bond ratings greatly complicates any
20 determination of investors' long-term expectations that
21 form the basis for DCF applications.
22

[7] *Williston Basin Interstate Pipeline Co.*, 104 FERC ¶ 61,036, at 14-15 (Jul. 3, 2003).

C. Risk Premium Analyses

1 Q. Briefly describe the risk premium method.

2 A. The risk premium method of estimating
3 investors' required rate of return extends the risk-return
4 tradeoff observed with bonds to common stocks. The cost of
5 equity is estimated by first determining the additional
6 return investors require to forgo the relative safety of
7 bonds and bear the greater risks associated with common
8 stock, and then adding this equity risk premium to the
9 current yield on bonds. Like the DCF model, the risk
10 premium method is capital market oriented. However, unlike
11 DCF models, which indirectly impute the cost of equity,
12 risk premium methods directly estimate investors' required
13 rate of return by adding an equity risk premium to
14 observable bond yields.

15 Q. How did you implement the risk premium
16 method?

17 A. I based my estimates of equity risk premiums
18 on (1) surveys of previously authorized rates of return on
19 common equity, (2) realized rates of return, and (3)
20 alternative applications of the Capital Asset Pricing Model
21 ("CAPM").

1 Authorized returns presumably reflect regulatory
2 commissions' best estimates of the cost of equity, however
3 determined, at the time they issued their final order.
4 Such returns should represent a balanced and impartial
5 outcome that considers the need to maintain a utility's
6 financial integrity and ability to attract capital.
7 Moreover, allowed returns are an important consideration
8 for investors and have the potential to influence other
9 observable investment parameters, including credit ratings
10 and borrowing costs. Thus, this data provides a logical
11 and frequently referenced basis for estimating equity risk
12 premiums.
13 Under the realized-rate-of-return approach, equity
14 risk premiums are calculated by measuring the rate of
15 return (including dividends, interest, and capital gains
16 and losses) actually realized on an investment in common
17 stocks and bonds over long historical periods. The
18 realized rate of return on bonds is then subtracted from
19 the return earned on common stocks to measure equity risk
20 premiums.
21 The CAPM approach measures the market-expected
22 return for a security as the sum of a risk-free rate and a
23 risk premium based on the portion of a security's risk that

1 cannot be eliminated by holding a well-diversified
2 portfolio. Under the CAPM, risk is represented by the beta
3 coefficient (β), which measures the volatility of a
4 security's price relative to the market as a whole. While
5 beta is not without controversy, the CAPM is routinely
6 referenced in the financial literature and in regulatory
7 proceedings.

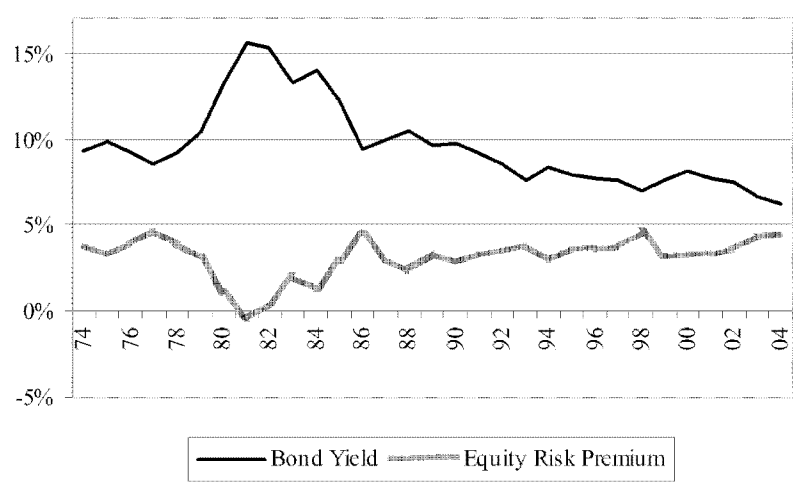
8 Q. How did you implement the risk premium
9 approach using surveys of allowed rates of return?

10 A. While the purest form of the survey approach
11 would involve querying investors directly, surveys of
12 previously authorized rates of return on common equity are
13 frequently referenced as the basis for estimating equity
14 risk premiums. The rates of return on common equity
15 authorized electric utilities by regulatory commissions
16 across the U.S. are compiled by Regulatory Research
17 Associates ("RRA") and published in its Regulatory Focus
18 report. In Exhibit WEA-3, the average yield on public
19 utility bonds is subtracted from the average allowed rate
20 of return on common equity for electric utilities to
21 calculate equity risk premiums for each year between 1974
22 and 2004. Over this 31-year period, these equity risk

1 premiums for electric utilities averaged 3.17%, and the
2 yield on public utility bonds averaged 9.59%.

3 Q. Is there any risk premium behavior that
4 needs to be considered when implementing the risk premium
5 method?

6 A. Yes. There is considerable evidence that
7 the magnitude of equity risk premiums is not constant and
8 that equity risk premiums tend to move inversely with
9 interest rates. In other words, when interest rate levels
10 are relatively high, equity risk premiums narrow, and when
11 interest rates are relatively low, equity risk premiums
12 widen. To illustrate, the graph below plots the yields on
13 public utility bonds (solid line) and equity risk premiums
14 (shaded line) shown on Exhibit WEA-3:



1 The graph clearly illustrates that the higher the level of
2 interest rates, the lower the equity risk premium, and vice
3 versa. The implication of this inverse relationship is
4 that the cost of equity does not move as much as, or in
5 lockstep with, interest rates. Accordingly, for a 1%
6 increase or decrease in interest rates, the cost of equity
7 may only rise or fall, say, 50 basis points. Therefore,
8 when implementing the risk premium method, adjustments may
9 be required to incorporate this inverse relationship if
10 current interest rate levels have changed since the equity
11 risk premiums were estimated.
12 Q. What cost of equity is implied by surveys of
13 allowed rates of return on equity?
14 A. As illustrated above, the inverse
15 relationship between interest rates and equity risk
16 premiums is evident. Based on the regression output
17 between the interest rates and equity risk premiums
18 displayed at the bottom of page 1 of Exhibit WEA-3, the
19 equity risk premium for electric utilities increased
20 approximately 43 basis points for each percentage point
21 drop in the yield on average public utility bonds. As
22 illustrated there, with the yield on average public utility

1 bonds in August 2005 being 5.51%, this implied a current
2 equity risk premium of 4.93% for electric utilities.
3 Adding this equity risk premium to the August 2005 yield on
4 triple-B public utility bonds of 5.80% produces a current
5 cost of equity for the utilities in the benchmark group of
6 approximately 10.7%.

7 Q. What else should be considered in applying
8 risk premium methods?

9 A. As noted earlier, because there is
10 widespread consensus that interest rates will increase
11 materially as the economy continues to strengthen, I also
12 applied the alternative risk premium methods based on a
13 forecasted bond yield for 2006.

14 Q. What cost of equity was produced by the
15 authorized rate of return approach after incorporating the
16 2006 bond yield forecast?

17 A. As shown on page 2 of Exhibit WEA-3,
18 incorporating a forecasted yield for 2006 and adjusting for
19 changes in interest rates since the study period implied an
20 equity risk premium of 4.37% for electric utilities.
21 Adding this equity risk premium to the implied yield on

1 triple-B public utility bonds for 2006 of 7.0% resulted in
2 an implied cost of equity of approximately 11.4%.
3 Q. How did you apply the realized-rate-of-
4 return approach?
5 A. Widely used in academia, the realized-rate-
6 of-return approach is based on the assumption that, given a
7 sufficiently large number of observations over long
8 historical periods, average realized market rates of return
9 will converge to investors' required rates of return. From
10 a more practical perspective, investors may base their
11 expectations of future earned returns on those realized in
12 the past, with average realized rates of return for
13 historical periods being widely reported in the financial
14 press and by investment advisory services as a guide to
15 future performance. By focusing on data for utilities
16 specifically, my realized rate of return approach avoided
17 the need to make assumptions regarding relative risk (*e.g.*,
18 beta) that are often embodied in applications of this
19 method.
20 Stock price and dividend data for the electric
21 utilities included in the S&P 500 Composite Index ("S&P
22 500") are available for the period 1946 through 2004. As

1 shown in Exhibit WEA-4, over this 59-year period realized
2 rates of return for these utilities have exceeded those on
3 public utility bonds by an average of 3.99%. In contrast
4 to other risk premium approaches, the realized-rate-of-
5 return method assumes that equity risk premiums are
6 stationary over time; therefore, no adjustment for the
7 inverse relationship between equity risk premiums and
8 interest rates was made. Adding this 3.99% equity risk
9 premium to the August 2005 yield of 5.80% on triple-B
10 public utility bonds produces a current cost of equity for
11 the electric utility proxy group of approximately 9.8%.
12 Once again, however, this does not consider the
13 anticipated increase in bond yields through 2006. Adding
14 this 3.99% equity risk premium to the 7.0% forecasted yield
15 on triple-B public utility bonds for 2006 implies cost of
16 equity of approximately 11.0%.
17 Q. Please describe your application of the
18 CAPM.
19 A. The CAPM is a theory of market equilibrium
20 that measures risk using the beta coefficient. Under the
21 CAPM, investors are assumed to be fully diversified, so the
22 relevant risk of an individual asset (*e.g.*, common stock)

is its volatility relative to the market as a whole. Beta reflects the tendency of a stocks' price to follow changes in the market. A stock that tends to respond less to market movements has a beta less than 1.00, while stocks that tend to move more than the market have betas greater than 1.00. The CAPM is mathematically expressed as:

$$R_j = R_f + \beta_j (R_m - R_f)$$

Where: R_j = required return for stock j;
R_f = risk-free rate;
R_m = expected return on the market portfolio; and,
β_j = beta, or systematic risk, for stock j.

I applied the CAPM to the ten companies in the utility proxy group using market risk premiums (R_m - R_f) based on (1) forward-looking estimates of investors' required rates of return and (2) historical realized rates of return.

Q. Please describe your forward-looking application of the CAPM.

A. Application of the CAPM to the utilities in the proxy group based on a forward-looking estimate for investors' required rate of return from common stocks is presented on Exhibit WEA-5. Rather than using historical data, the expected market rate of return was estimated by conducting a DCF analysis on the 356 dividend paying firms

1 in the S&P 500, with each firm's dividend yield and growth
2 rate being weighted by its proportionate share of total
3 market value.[8]
4 The dividend yield for each firm was obtained from
5 Value Line, with the growth rate being equal to the average
6 of the earnings growth projections for each firm published
7 by I/B/E/S International, Inc. ("IBES") and Value Line.
8 Based on the weighted average of the projections for the
9 356 individual firms, current estimates imply an average
10 growth rate over the next five years of 11.4%. Combining
11 this average growth rate with a dividend yield of 2.1%
12 results in a current cost of equity estimate for the market
13 as a whole of approximately 13.5%. Subtracting a 4.5%
14 risk-free rate based on the September 2005 average yield on
15 20-year Treasury bonds from the 13.5% forward-looking rate
16 of return produced a market equity risk premium of 9.0%.
17 Multiplying this risk premium by the average Value Line
18 beta of 0.89 for the utilities in the proxy group, and then
19 adding the resulting 8.0% risk premium to the September
20 2005 average long-term Treasury bond yield, resulted in a
21 current cost of equity of approximately 12.5%.

[8] This is analogous to the approach relied on by the Illinois Commerce Commission Staff in Docket No. 96-0486 (*Testimony of Joy Nicdao-Cuyygan*).

1 Q. What cost of equity is implied by this
2 forward-looking application of the CAPM after incorporating
3 2006 projected government bond yields?
4 A. As shown on page 2 of Exhibit WEA-5,
5 interest rate projections published by GlobalInsight, EIA,
6 and Blue Chip imply a projected yield on 20-year Treasury
7 bonds of 5.5% for 2006, which results in a market risk
8 premium of 8.0%. Once again multiplying the market risk
9 premium by the average Value Line beta of 0.89 for the
10 electric utilities in the proxy group, and then adding the
11 resulting 7.1% risk premium to the 5.5% long-term Treasury
12 bond yield for 2006, implied a cost of equity of
13 approximately 12.6%.
14 Q. What other CAPM analyses did you conduct to
15 estimate the cost of equity?
16 A. I also applied the CAPM using risk premiums
17 based on historical realized rates of return. This
18 approach to estimating investors' equity risk premiums is
19 premised on the assumption that, given a sufficiently large
20 number of observations over long, historical periods,
21 average realized market rates of return will converge to
22 investors' required rates of return.

1 Q. What CAPM cost of equity is produced based
2 on historical realized rates of return for stocks and long-
3 term government bonds?
4 A. I applied the CAPM using data published by
5 Ibbotson Associates, which is perhaps the most exhaustive
6 and widely referenced annual study of realized rates of
7 return. Application of the CAPM based on historical
8 realized rates of return is presented in Exhibit WEA-6. In
9 their *2005 Yearbook, Valuation Edition*, Ibbotson Associates
10 reported that, over the period 1926 through 2004, the
11 arithmetic mean realized rate of return on the S&P 500
12 exceeded that on long-term government bonds by 7.2%.[9]
13 Multiplying this historical market risk premium by the
14 average Value Line beta of 0.89 produced an equity risk
15 premium of 6.4% for the electric utility proxy group. As
16 shown on page 1 of Exhibit WEA-6, adding this equity risk
17 premium to the September 2005 average yield on 20-year

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[9] Ibbotson Associates computes the equity risk premium by subtracting the income return (not the total return) on long-term Treasury bonds from the return on common stocks. As Ibbotson Associates noted [*2005 Yearbook, Valuation Edition* at 75]:

> Price changes in bonds due to unanticipated changes in yields introduce price risk into the total return. Therefore, the total return on the bond series does not represent the riskless rate of return. The income return better represents the unbiased estimate of the purely riskless rate of return, since an investor can hold a bond to maturity and be entitled to the income return with no capital loss.

1 Treasury bonds of 4.5% resulted in an implied cost of
2 equity of 10.9%. As shown on page 2 of Exhibit WEA-6,
3 after incorporating a the 5.5% projected government bond
4 yield for 2006, application of the CAPM based on historical
5 realized rates of return implied a cost of equity of 11.9%.

6 Q. What else should be considered in evaluating
7 CAPM cost of equity estimates based on historical realized
8 rates of return?

9 A. The CAPM model, like the DCF approach, is an
10 *ex-ante*, or forward-looking model based on expectations of
11 the future. As a result, in order to accurately estimate
12 required returns the CAPM must be applied using data that
13 reflects the expectations of actual investors. While
14 reference to historical data represents one way to apply
15 the CAPM, these realized rates of return reflect, at best,
16 an indirect estimate of investors' current requirements.
17 Because my forward-looking applications of the CAPM look
18 directly at current expectations in the capital markets,
19 these results are apt to provide a more meaningful guide to
20 investors' required rate of return.

1 Q. Please summarize the results of your risk
2 premium analyses.
3 A. The cost of equity estimates implied by my
4 risk premium analyses are summarized in the following
5 table:

Risk Premium Approach	Cost of Equity Estimate
Authorized Returns	
Current Yield	10.7%
Projected Yield	11.4%
Realized Rates of Return	
Current Yield	9.8%
Projected Yield	11.0%
CAPM - Forward-looking	
Current Yield	12.5%
Projected Yield	12.6%
CAPM - Historical	
Current Yield	10.9%
Projected Yield	11.9%

D. Discounted Cash Flow Analyses

6 Q. How are DCF models used to estimate the cost
7 of equity?
8 A. The use of DCF models is essentially an
9 attempt to replicate the market valuation process that sets
10 the price investors are willing to pay for a share of a
11 company's stock. The model rests on the assumption that
12 investors evaluate the risks and expected rates of return
13 from all securities in the capital markets. Given these

1 expected rates of return, the price of each stock is
2 adjusted by the market until investors are adequately
3 compensated for the risks they bear. Therefore, we can
4 look to the market to determine what investors believe a
5 share of common stock is worth. By estimating the cash
6 flows investors expect to receive from the stock in the way
7 of future dividends and capital gains, we can calculate
8 their required rate of return. In other words, the cash
9 flows that investors expect from a stock are estimated, and
10 given its current market price, we can "back-into" the
11 discount rate, or cost of equity, that investors
12 presumptively used in bidding the stock to that price.
13 Q. What market valuation process underlies DCF
14 models?
15 A. DCF models are derived from a theory of
16 valuation which assumes that the price of a share of common
17 stock is equal to the present value of the expected cash
18 flows (i.e., future dividends and stock price) that will be
19 received while holding the stock, discounted at investors'
20 required rate of return, or the cost of equity.
21 Notationally, the general form of the DCF model is as
22 follows:

$$P_0 = \frac{D_1}{(1+k_e)^1} + \frac{D_2}{(1+k_e)^2} + \cdots + \frac{D_t}{(1+k_e)^t} + \frac{P_t}{(1+k_e)^t}$$

where: P_0 = Current price per share;
P_t = Expected future price per share in period t;
D_t = Expected dividend per share in period t;
k_e = Cost of equity.

That is, the cost of equity is the discount rate that will equate the current price of a share of stock with the present value of all expected cash flows from the stock.

Q. Has this general form of the DCF model customarily been used to estimate the cost of equity in rate cases?

A. No. In an effort to reduce the number of required estimates and computational difficulties, the general form of the DCF model has been simplified to a "constant growth" form. But converting the general form of the DCF model to the constant growth DCF model requires a number of strict assumptions. These include:

- A constant growth rate for both dividends and earnings;
- A stable dividend payout ratio;
- The discount rate exceeds the growth rate;
- A constant growth rate for book value and price;
- A constant earned rate of return on book value;

- No sales of stock at a price above or below book value;
- A constant price-earnings ratio;
- A constant discount rate (i.e., no changes in risk or interest rate levels and a flat yield curve); and,
- All of the above extend to infinity.

Given these assumptions, the general form of the DCF model can be reduced to the more manageable formula of:

$$P_0 = \frac{D_1}{k_e - g}$$

where: g = Investors' long-term growth expectations.

The cost of equity (K_e) can be isolated by rearranging terms:

$$k_e = \frac{D_1}{P_0} + g$$

This constant growth form of the DCF model recognizes that the rate of return to stockholders consists of two parts: 1) dividend yield (D_1/P_0), and 2) growth (g). In other words, investors expect to receive a portion of their total return in the form of current dividends and the remainder through price appreciation.

1 Q. Are the assumptions underlying the constant
2 growth form of the DCF model met in the real world?
3 A. In practice, none of the assumptions
4 required to convert the general form of the DCF model to
5 the constant growth form are ever strictly met.
6 Nevertheless, where earnings are derived from stable
7 activities, and earnings, dividends, and book value track
8 fairly closely, the constant growth form of the DCF model
9 offers a reasonable working approximation of stock
10 valuation that provides useful insight as to investors'
11 required rate of return.
12 Q. How is the constant growth form of the DCF
13 model typically used to estimate the cost of equity?
14 A. The first step in implementing the constant
15 growth DCF model is to determine the expected dividend
16 yield (D_1/P_0). This is usually calculated based on an
17 estimate of dividends to be paid in the coming year divided
18 by the current price of the stock. The second, and more
19 controversial, step is to estimate investors' long-term
20 growth expectations (g). Since book value, dividends,
21 earnings, and price are all assumed to move in lock-step in
22 the constant growth DCF model, estimates of expected growth

are sometimes derived from historical rates of growth in these variables under the presumption that investors expect these rates of growth to continue into the future.

Alternatively, a firm's internal growth can be estimated based on the product of its earnings retention ratio and earned rate of return on equity. This growth estimate may rely on either historical or projected data, or both. A third approach is to rely on security analysts' projections of growth as proxies for investors' expectations. The final step is to sum the dividend yield and estimated growth rate to arrive at an estimate of the cost of equity.

Q. How did you determine the dividend yield for the proxy group of utilities?

A. Estimates of dividends to be paid by each of these utilities over the next twelve months, obtained from Value Line, served as D_1. This annual dividend was then divided by the corresponding stock price for each utility to arrive at the expected dividend yield. The expected dividends, stock price, and resulting dividend yields for the firms in the reference group of western utilities are presented on Exhibit WEA-7. As shown there, dividend

1 yields for the ten firms in the electric utility proxy
2 group ranged from 2.2% to 4.6%, with the average being
3 3.5%.

4 Q. What are investors most likely to consider
5 in developing their long-term growth expectations?

6 A. In constant growth DCF theory, earnings,
7 dividends, book value, and market price are all assumed to
8 grow in lockstep and the growth horizon of the DCF model is
9 infinite. But implementation of the DCF model is more than
10 just a theoretical exercise; it is an attempt to replicate
11 the mechanism investors used to arrive at observable stock
12 prices. Thus, the only "g" that matters in applying the
13 DCF model is that which investors expect and have embodied
14 in current market prices. While the uncertainties inherent
15 with common stock make estimating investors' growth
16 expectations a difficult task for any company, in the case
17 of utilities, the problem is exacerbated due to the
18 unsettled conditions in the industry, which contrast with
19 the steady-state environment assumed by the constant growth
20 DCF model. This lack of stability is exemplified by
21 IDACORP, Inc.'s decision to preserve cash by cutting common
22 dividend payments significantly during 2003, in part due to

1 the pressures associated with shortfalls in hydro
2 generation.

3 Q. Are historical dividend growth rates likely
4 to provide a meaningful guide to investors' growth
5 expectations for electric utilities?

6 A. No. In response to more accentuated
7 business risks in the industry, utilities adopted dividend
8 policies that were much more conservative than in the past.
9 As a result, dividend growth in the utility industry has
10 remained largely stagnant in recent years as utilities
11 conserved financial resources to provide a hedge against
12 heightened uncertainties. Responding to this trend,
13 investors' focus increasingly shifted from dividends to
14 earnings as a measure of long-term growth, as payout ratios
15 for firms in the electric utility industry trended downward
16 from approximately 80% historically to on the order of
17 60%.[10]

18 Q. What about projected dividend growth rates?

19 A. As the industry recovers from the financial
20 challenges of the last several years, some electric
21 utilities have begun to reevaluate their dividend policies

[10] See, *e.g.*, The Value Line Investment Survey (Sep. 15, 1995 at 161, Aug. 12, 2005 at 1776).

1 and reinstate increases to their quarterly payout. While
2 investors have recently expressed renewed interest in
3 dividend payments, Value Line's most recent forecast
4 indicates negative projected dividend growth for one of the
5 proxy firms, while one is listed as "Nil" and another as
6 "NMF".[11] Negative or zero growth rates imply a cost of
7 equity equal to, or below, the utility's dividend yield.
8 Such nonsensical results provide little guidance as to
9 investors' expectations for the electric utility proxy
10 group.

11 Q. What other trends do investors consider in
12 developing growth expectations?

13 A. Trends in earnings, which ultimately support
14 future dividends and share prices, are likely to play a
15 pivotal role in determining investors' long-term growth
16 expectations. Indeed, the importance of earnings in
17 evaluating investors' expectations and requirements is well
18 accepted in the investment community. As noted in *Finding*
19 *Reality in Reported Earnings* published by the Association
20 for Investment Management and Research:

21 [E]arnings, presumably, are the basis for the
22 investment benefits that we all seek. "Healthy

[11] The Value Line Investment Survey (Aug. 12, 2005).

> earnings equal healthy investment benefits" seems a logical equation, but earnings are also a scorecard by which we compare companies, a filter through which we assess management, and a crystal ball in which we try to foretell the future.[12]

Value Line's near-term projections and its Timeliness Rank, which is the principal investment rating assigned to each individual stock, are also based primarily on various quantitative analyses of earnings. As Value Line explained:

> The future earnings rank accounts for 65% in the determination of relative price change in the future; the other two variables (current earnings rank and current price rank) explain 35%.[13]

The fact that investment advisory services, such as Value Line and IBES, focus on growth in earnings indicates that the investment community regards this as a superior indicator of future long-term growth. Indeed, *Financial Analysts Journal* reported the results of a survey conducted to determine what analytical techniques investment analysts actually use.[14] Respondents were asked to rank the relative importance of earnings, dividends, cash flow, and book value in analyzing securities. Of the 297 analysts that

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[12] Association for Investment Management and Research, "Finding Reality in Reported Earnings: An Overview", p. 1 (Dec. 4, 1996).
[13] The Value Line Investment Survey, *Subscriber's Guide*, p. 53.
[14] Block, Stanley B., "A Study of Financial Analysts: Practice and Theory", *Financial Analysts Journal* (July/August 1999).

1 responded, only 3 ranked dividends first while 276 ranked
2 it last. The article concluded:

3 Earnings and cash flow are considered far more
4 important than book value and dividends.[15]

5 Q. What are security analysts currently
6 projecting in the way of earnings growth for the firms in
7 the electric utility proxy group?

8 A. The consensus earnings growth projections
9 for each of the firms in the reference group of electric
10 utilities reported by IBES and published in S&P's *Earnings*
11 *Guide* are shown on Exhibit WEA-8. Also presented are the
12 earnings growth projections reported by Value Line, First
13 Call Corporation ("First Call"), Zack's Investment Research
14 ("Zacks"), and Reuters. As shown there, these security
15 analysts' projections suggested growth the order of 5.3% to
16 5.7% for the reference group of electric utilities:

Electric Utility Proxy Group

Service	Growth Rate
IBES	5.3%
Value Line	5.5%
First Call	5.5%
Zacks	5.7%
Reuters	5.7%

[15] *Id.* at 88.

1 Q. What considerations are relevant in
2 evaluating these near-term growth rates for electric
3 utilities?
4 A. Short-term projected growth rates may be
5 colored by lingering uncertainties regarding the near-term
6 direction of the economy in general and the spate of
7 challenges recently faced in the electric power industry
8 specifically. This short-term "hangover" is exemplified by
9 Value Line, which has assigned its Utilities sector the
10 lowest ranking of all 10 sectors it covers for year-ahead
11 stock price performance,[16] while noting that "[t]he electric
12 utility industry carries a below-average industry
13 Timeliness rank."[17] While this cautious outlook may be
14 indicative of relatively low near-term growth projections,
15 it does not necessarily reflect investors' long-term
16 expectations for the industry.
17 Q. How else are investors' expectations of
18 future long-term growth prospects often estimated for use
19 in the constant growth DCF model?
20 A. Based on the assumptions underlying constant
21 growth theory, conventional applications of the constant

[16] The Value Line Investment Survey, *Selection & Opinion* (July 29, 2005) at 1606.
[17] The Value Line Investment Survey (July 1, 2005) at 695.

growth DCF model often examine the relationships between retained earnings and earned rates of return as an indication of the sustainable growth investors might expect from the reinvestment of earnings within a firm. The sustainable growth rate is calculated by the formula, $g = br + sv$, where "b" is the expected retention ratio, "r" is the expected earned return on equity, "s" is percent of common equity expected to be issued annually as new common stock, and "v" is the equity accretion rate.

Q. What is the purpose of the "sv" term?

A. Under DCF theory, the "sv" factor is a component of the growth rate designed to capture the impact of issuing new common stock at a price above, or below, book value. When a company's stock price is greater than its book value per share, the per-share contribution in excess of book value associated with new stock issues will accrue to the current shareholders. The higher book value per share leads to higher expected earnings and dividends, with the "sv" factor incorporating this additional growth component.

1 Q. What growth rate does the earnings retention
2 method suggest for the proxy group?
3 A. The sustainable, "br + sv" growth rates for
4 each firm in the proxy group are shown on Exhibit WEA-9.
5 For each firm, the expected retention ratio (b) was
6 calculated based on Value Line's projected dividends and
7 earnings per share. Likewise, each firm's expected earned
8 rate of return (r) was computed by dividing projected
9 earnings per share by projected net book value. Because
10 Value Line reports end-of-year book values, an adjustment
11 was incorporated to compute an average rate of return over
12 the year, consistent with the theory underlying this
13 approach to estimating investors' growth expectations.
14 Meanwhile, the percent of common equity expected to be
15 issued annually as new common stock (s) was equal to the
16 product of the projected market-to-book ratio and growth in
17 common shares outstanding, while the equity accretion rate
18 (v) was computed as 1 minus the inverse of the projected
19 market-to-book ratio. As shown there, this method resulted
20 in an average expected growth rate for the group of ten
21 utilities of 4.6%.

1 Q. What did you conclude with respect to the
2 growth expectations implied for the reference group of
3 western utilities?
4 A. I concluded that the measures discussed
5 above indicated growth on the order of 5.5% for the average
6 firm in the utility proxy group.
7 Q. What cost of equity was implied for the
8 proxy group of utilities using the DCF model?
9 A. Combining the 3.5% average dividend yield
10 with the 5.5% growth rate implied a DCF cost of equity for
11 this group of electric utilities of 9.0%. As discussed in
12 my testimony, however, it would be unreasonable to
13 establish an ROE based on this single DCF result.
14 Q. Does this conclude your Additional Direct
15 testimony?
16 A. Yes, it does.