BEFORE THE

SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

DIRECT TESTIMONY OF

WILLIAM E. AVERA

On Behalf of Black Hills Power, Inc.

Docket No. EL06-________

June 30, 2006

DIRECT TESTIMONY OF WILLIAM E. AVERA

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ON BEHALF OF BLACK HILLS POWER, INC.

Docket No. ____________

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 Appendix A.

A. Overview

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present to the South Dakota Public Utilities Commission ("SDPUC" or the "Commission") my independent assessment of the fair rate of return on equity ("ROE") for the jurisdictional electric utility operations of Black Hills Power, Inc. ("Black Hills" or "the Company"). In addition, I also examined the reasonableness of Black Hills' requested capital structure, considering both the specific risks faced by Black Hills and other industry guidelines.

Q. Please summarize the basis of your knowledge and conclusions concerning the issues to which you are testifying in this case.

A. To prepare my testimony, I used information from a variety of sources that would normally be relied upon by a person in my capacity. In connection with the present filing, I considered and relied upon corporate disclosures and management discussions, publicly available financial reports and filings, and other published information relating to Black Hills and its parent company, Black Hills Corporation ("Black Hills Corp."). I also reviewed information relating generally to capital market conditions and specifically to investor perceptions, requirements, and expectations for electric utilities. These sources, coupled with my experience in the fields of finance and utility regulation, have given me a working knowledge of investors' requirements for Black Hills as it competes to attract capital, and they form the basis of my analyses and conclusions.

Q. What is the role of the return on equity in setting a utility's rates?

A. The ROE compensates equity investors for the use of their capital to finance the plant and equipment necessary to provide utility service. Investors commit capital only if they expect to earn a return on their investment commensurate with returns available from alternative investments with comparable risks. To be consistent with sound regulatory economics and the standards set forth by the United States Supreme Court in the *Bluefield*[1] and *Hope*[2] cases, a utility's allowed return on equity should be sufficient to (1) fairly compensate the utility's investors, (2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and (3) maintain the utility's financial integrity.

[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).

Q. How is your testimony organized?

A. I first reviewed the operations and finances of Black Hills and the general conditions in the electric utility industry and the economy. With this as a background, I developed the principles underlying the cost of equity concept and then conducted various quantitative analyses to estimate the cost of equity for a group of reference utilities. These included discounted cash flow ("DCF") analyses, risk premium methods encompassing alternative approaches and studies, and reference to comparable earned rates of return expected for utilities and industrial firms. From the cost of equity range indicated by my analyses, a fair rate of return on equity was selected taking into account the economic requirements and specific risks and potential challenges for Black Hills, as well as other factors (*e.g.*, flotation costs) that are properly considered in setting a fair rate of return on equity for the Company's jurisdictional electric utility operations in South Dakota.

B. Summary of Conclusions

Q. What are your findings regarding the fair rate of return on equity for Black Hills?

A. Based on the results of my analyses and the economic requirements necessary to support continuous access to capital, I recommend that Black Hills be authorized a fair rate of return on equity of 11.75%. The bases for my conclusion are summarized below:

- *Considering investors' expectations for capital markets and the need to support financial integrity and fund crucial capital investment even under adverse circumstances, it is my opinion that 11.75% is a reasonable ROE for Black Hills. Specifically, I concluded that:*
- *Applications of alternative quantitative methods to a proxy group of other electric utilities operating in the Western U.S. implied a cost of equity range of 11.0% to 12.0%, before considering an allowance for flotation costs;*
- *Expectations for higher long-term interest rates should be considered in establishing a fair rate of return for Black Hills;*
- *Incorporating a 25 basis-point allowance for equity flotation costs resulted*

in a fair rate of return range for the electric utility proxy group of 11.25% to 12.25%; and

- *Based on the midpoint of this range, 11.75% represents a reasonable rate of return on common equity for Black Hills.*

Q. What is your conclusion as to the reasonableness of the Company's capital structure?

A. Based on my evaluation, I concluded that a common equity ratio of approximately 54% represents a reasonable basis from which to calculate Black Hills' overall rate of return. This conclusion was based on the following findings:

- *Black Hills' proposed common equity ratio is consistent with capital structure ratios for the electric utilities in the proxy group used to estimate the cost of equity;*
- *The additional uncertainties associated with Black Hills' relatively small size warrant a more conservative financial posture; and,*
- *Black Hills' requested capitalization reflects the Company's need to support its credit standing and financial flexibility as it seeks to fund system investments and meet the requirements of customers.*

Q. What other evidence did you consider in evaluating your recommendation in this case?

A. My recommendation was reinforced by the following findings:

- *While investors would perceive the approval of Black Hills' proposed fuel and purchased power adjustment clause ("FPPA") as a positive step and supportive of its financial integrity, they understand that this would not completely shield the Company from uncertainties over power supply costs;*
- *Considering investors' heightened awareness of the risks associated with the electric power industry and the damage that results when a utility's financial flexibility is compromised, supportive regulation is crucial;*
- *Sensitivity to regulatory uncertainties has increased dramatically and investors recognize that constructive regulation is a key ingredient in supporting utility credit ratings and financial integrity;*
- *Black Hills must compete for investors' capital with other utilities and businesses of comparable risk. If Black Hills 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;*

- *This conclusion is reinforced by investors' continued focus on the unsettled conditions in restructured wholesale energy markets and the implications of Black Hills' relatively small size, which implies a level of investment risk and required return that exceeds that of the proxy group used to estimate the cost of equity; and,*
- *Ultimately, it is customers and the service area economy that benefit when the utility has the opportunity to maintain the financial wherewithal that is necessary, not just to ensure short-term liquidity, but to take actions to provide an efficient, reliable energy supply over the long-term.*

II. FUNDAMENTAL ANALYSES

Q. What is the purpose of this section?

A. As a predicate to subsequent quantitative analyses, this section briefly reviews the operations and finances of Black Hills. In addition, it examines the risks and prospects for the electric utility industry and conditions in the capital markets and the general economy. An understanding of the fundamental factors driving the risks and prospects of electric utilities is essential in developing an informed opinion of investors' expectations and requirements that are the basis of a fair rate of return.

A. Black Hills Power, Inc.

Q. Briefly describe Black Hills.

A. A wholly owned subsidiary of Black Hills Corp., the Company is primarily engaged in the generation, transmission, and distribution of electric power to approximately 63,500 customers within a 9,300 square mile area of western South Dakota, northeastern Wyoming, and Southeastern Montana. Approximately 90% of Black Hills' retail electric revenues in 2005 were generated in South Dakota. During the most recent fiscal year, Black Hills' energy deliveries totaled approximately 3.1 million megawatt hours ("mWh"). The Company's revenue mix was comprised of 21% residential, 26% commercial, and 11%

industrial sales revenue, with 12% from contract wholesale, 25% wholesale off-system, and 5% municipal and other. As of December 31, 2005, Black Hills had total assets of approximately $464 million, with operating revenues for the year totaling approximately $189 million.

Black Hills existing generating units, located in South Dakota and Wyoming, provide total generating capacity of approximately 435 megawatts ("MW"), with coal-fired capacity accounting for approximately 56% of company-owned facilities and natural gas and oil-fired plants making up 44%. In addition to its own generating capacity, Black Hills also relies on power purchased under two long-term contracts with PacifiCorp to meet approximately 11% of its total capacity requirements.

Black Hills' transmission and distribution facilities consist of approximately 447 pole miles of high voltage lines and 511 miles of lower voltage lines. In addition, Black Hills is 35% owner of an AC-DC-AC transmission tie that provides an interconnection between the Western and Eastern transmission grids with a total transfer capacity of 400 MW. In connection with certain wholesale sales, Black Hills also has firm transmission access to deliver power on specific segments of PacifiCorp's transmission system.

The Company's retail electric operations are subject to the jurisdiction of the SDPUC and the Wyoming Public Service Commission. A retail rate freeze for Black Hills' South Dakota jurisdiction, which had been in effect since 1995, expired on January 1, 2005. During the ten-year term of the rate freeze, Black Hills was prohibited, subject to certain limited exceptions, from filing for any increase in rates or invoking any fuel and purchased power adjustment tariff during the freeze period. While Black Hills' rates do not currently include an FPPA, as discussed in the testimony of Kyle White and Jacqueline Sargent, Black Hills is proposing to implement a modified FPPA as part of this proceeding.

Q. Does Black Hills anticipate the need for additional capital going forward?

A. Most definitely. Black Hills will require capital investment to meet customer growth, provide for necessary maintenance and replacements of its utility infrastructure, as well as fund new investment in electric generation, transmission and distribution facilities. Black Hills anticipates capital requirements of approximately $82.8 million over the three years 2006-2008, which is equivalent to approximately 21% of the Company's investment in net plant at December 31, 2005. Support for Black Hills' financial integrity and flexibility will be instrumental in attracting the capital necessary to fund these projects in an effective manner.

Q. What credit ratings have been assigned to Black Hills?

A. Black Hills has been assigned a corporate credit rating of "BBB-" by Standard & Poor's Corporation ("S&P") and an issuer credit rating of "Baa2" by Moody's Investor Services, Inc. ("Moody's"). Credit rating on Black Hills' first mortgage bonds are "BBB" and "Baa1" by S&P and Moody's, respectively. S&P maintains a "negative" outlook on Black Hills, indicating the potential for deterioration in the Company's credit standing going forward.

B. Electric Utility Industry

Q. What general conditions have recently characterized the electric utility industry?

A. Beginning in the 1990s, the industry experienced significant structural change resulting from market forces and decontrol initiatives. At least initially, this process was largely driven by regulatory reforms at the federal level. The national Energy Policy Act of 1992 greatly increased prospective competition for the production and sale of power at the wholesale level, with the Federal Energy Regulatory Commission ("FERC") being an aggressive proponent for actions designed to foster greater competition in markets for wholesale power supply.

Most market observers agree that, while "open access" to FERC-jurisdictional transmission facilities has resulted in more competition in wholesale energy markets, it has also introduced substantial risks – particularly for utilities that participate in wholesale electric markets.

Q. What impact did the Western power crisis have on investors' risk perceptions for firms involved in the electric power industry?

A. These events caused investors to rethink their assessment of the relative risks associated with the electric power industry. A well-publicized energy crisis throughout the West wreaked havoc on the customers, utilities, and policymakers. It also had dramatic repercussions for wholesale power markets and investors and utilities nationwide. In many states, regulators and legislators placed restructuring initiatives for the retail sector of the electric industry on hold as the financial implications of the Western energy crisis brought the uncertainties associated with today's power markets into sharp focus for the investment community and other stakeholders. While the case of California represents an extreme example, there is every indication that investors' risk perceptions for all electric utilities shifted sharply upward in response to these events.

Q. How were Western utilities impacted by conditions in the electric power industry?

A. The financial integrity of many utilities in the region was severely damaged by the maelstrom of the Western energy crisis. While a full description of the Western power crisis and its effects is beyond the scope of this testimony, the chaotic market conditions were felt directly and with full force. S&P cited the debilitating impact of these developments on investors' willingness to provide capital and recognized that the end result of investors' waning confidence in the industry was reduced access to capital.[3]

Utilities were forced to use cash flows from operations, various bank borrowings, and short- and long-term debt to fund unrecovered energy supply costs. This led to a sharp deterioration in financial condition, a severe liquidity crunch, and a dramatic increase in credit risk. As a result, commercial banks were highly reticent to extend financing for ongoing operations or new construction and counterparties involved in meeting the utilities' energy needs became unwilling to transact business absent special credit terms. To varying degrees, utilities throughout the Western U.S. were confronted with the difficult task of maintaining reliable service and financial integrity in a power market characterized by short supply and unprecedented price volatility. As a result, investors recognize that volatile markets and inopportune reliance on wholesale purchases to meet resource needs can constitute a dangerous combination, exposing the utility to the risk of reduced cash flows and unrecovered power supply costs.

Q. Was there a corresponding impact on the industry's credit standing?

A. Yes. The last several years witnessed steady erosion in credit quality throughout the utility industry, both as a result of revised perceptions of the risks in the industry and the weakened finances of the utilities themselves. For example, during 2002, S&P recorded 182 downgrades in the utility industry, versus only fifteen upgrades,[4] while Moody's

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[3] Standard & Poor's Corporation, "U.S. Power Industry Experiences Precipitous Credit Decline in 2002; Negative Slope Likely to Continue," *RatingsDirect* (Jan. 15, 2003).

[4] *Id.*

downgraded 109 utility issuers and upgraded three.[5] Credit quality continued to decline during 2003, with S&P reporting that downgrades outpaced upgrades by more than fifteen to one in the fourth quarter of 2003.[6] While the pace and scale of negative ratings actions has since diminished, S&P reported that the majority of the companies in the utility sector now fall in the triple-B rating category and noted a continued negative bias in the credit outlook.[7]

Q. Is the potential for energy market volatility an ongoing concern for investors?

A. Most definitely. Investors recognize that the prospect of further turmoil in power markets cannot be discounted, with S&P reporting continued spikes in wholesale market prices in the aftermath of the crisis.[8] S&P concluded that, while the severe distortions that characterized the energy crisis of 2000-2001 have faded, "[n]atural gas volatility, poor hydro conditions in the Northwest, the Southwest's sustained drought, and uncertainty over future generation development" are "daily reminders" of industry challenges.[9] Meanwhile, the FERC Staff has continued to recognize the ongoing potential for market disruption in the West, as a 2005 market assessment report concluded:

> Our review of supply and demand conditions in the west this summer indicates that there may be periods of market tightness most likely expressed as price spikes and possible interruptions.[10]

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[5] Moody's Investors Service, *Credit Perspectives* (Jul. 14, 2003) at 33.

[6] Standard & Poor's Corporation, "U.S. Utilities' Ratings Decline Continued in 2003, But Pace Slows," *RatingsDirect* (Feb. 2, 2004).

[7] Standard & Poor's Corporation, "Pace of U.S. Utility Rating Actions Picked Up In 2005; Downgrades Dominate," *RatingsDirect* (Feb. 1, 2006).

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

[9] Standard & Poor's Corporation, *Utilities & Perspectives* (Oct. 18, 2004).

[10] Federal Energy Regulatory Commission, Office of Market Oversight and Investigations, "Summer Energy Market Assessment 2005," (May 4, 2005) at 9.

In recent years utilities and their customers have also had to contend with dramatic fluctuations in gas costs due to ongoing price volatility in the spot markets.[11] S&P noted the danger posed by "high and volatile natural gas prices," which increase the uncertainties associated with power supply costs.[12] This sensitivity was magnified by fallout of the natural disaster in the Gulf Coast region.[13] Natural Gas Intelligence cited investor sentiment that natural gas markets have entered "a dangerous time,"[14] and concluded that:

> Despite natural gas storage levels sitting near record highs, natural gas futures prices remain lofty compared to past years, likely due to elevated petroleum prices and fear-based premiums attached to the upcoming hurricane season.[15]

In addition, while coal has historically been a relatively stable source of fuel, the potential for price volatility has raised investors' concerns. In an article entitled "Rising Coal Prices May Threaten U.S. Utility Credit Profiles," S&P noted that:

> More recently, several current and structural developments for the coal mining industry have resulted in a dramatic increase in spot coal prices.[16]

These concerns have been exacerbated by delays and uncertainties over transportation, which have forced some utilities to curtail production at coal-fired generating facilities in

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[11] For example, the Energy Information Administration ("EIA") reported 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,* Mar. 27, 2003 and Oct. 13, 2005).

[12] Standard & Poor's Corporation, "Prolonged High Natural Gas Prices May Increase Credit Risk for U.S. Gas Distributors," *RatingsDirect* (Jan. 19, 2005)

[13] See, *e.g.*, Economist Intelligence Unit, Ltd., "World Commodities – Natural gas market outlook," (Sep. 1, 2005) at 1.

[14] "Natural Gas Prices Buoyed by Petroleum Strength, Hurricane Concerns," *Natural Gas Intelligence* (Apr. 10, 2006).

[15] *Id.*

[16] Standard & Poor's Corporation, "Rising Coal Prices May Threaten U.S. Utility Credit Profiles," *RatingsDirect* (Aug. 12, 2004).

the face of declining fuel inventories.[17] Indeed, the SDPUC recently hosted a meeting of stakeholders to address the implications of coal transportation constraints on electricity generation and costs.[18]

Q. Would the modified FPPA proposed by Black Hills remove the risk associated with fluctuations in power supply costs?

A. No. While approval of the FPPA would be supportive of the Company's financial integrity, it does not apply to 100% of Black Hills' power costs. Moreover, even for utilities with permanent energy cost adjustment mechanisms in place, there can be a significant lag between the time the utility actually incurs the expenditure and when it is recovered from customers. Citing the example of a gas utility, S&P observed that:

> Slow recovery could impinge on the firm's liquidity as short-term funds are consumed to finance high-cost gas purchases. In turn, this may necessitate a large bank line that increases borrowing costs.[19]

In the case of Black Hills, the proposed FPPA calls for the Company to absorb a portion of any increase in the cost of gas and purchased power above base rates. In addition, the FPPA would not insulate Black Hills from the need to finance accrued power production and supply costs.

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[17] See, *e.g.*, Smith, Rebecca and Machalaba, Daniel, "Taking Lumps: As Utilities Seek More Coal, Railroads Struggle to Deliver --- Snags in Wyoming Ripple Through Taxed Network; Power Plants Run Short --- A 5,833-Hopper-Car Deficit," The Wall Street Journal (Mar. 15, 2006) at A1.

[18] See, *e.g.*, "Group discusses coal shipping, electricity costs," *Press Release*, South Dakota Public Utilities Commission (April 25, 2006).

[19] Standard & Poor's Corporation, "Prolonged High Natural Gas Prices May Increase Credit Risk for U.S. Gas Distributors," *RatingsDirect* (Jan. 19, 2005).

Q. Would the proposed FPPA protect Black Hills from the potential for regulatory disallowances?

A. No. Even with an energy cost adjustment mechanism, investors recognize the ongoing potential for regulatory disallowances. As S&P observed:

> … FPPAs vary substantially in their ability to protect utilities daily and under catastrophic market movement. Moreover, it is critical to note that FPPAs are not a substitute for supportive regulation; the regulator's ability to disallow costs through ex-post prudency review, regardless of the existence of a FPPA, is a fact of life for utilities.[20]

Similarly, Fitch noted that "because of the lag between when the excess costs are incurred and when they are recovered and the potential substantial disallowances of such costs," significant uncertainties remain even for utilities with fuel and purchased power cost adjustment mechanisms.[21] As Fitch recently concluded, implementation of any rate adjustment "is still subject to regulatory and political risk, particularly in a period of rising energy costs."[22]

Q. What other developments have contributed to investors' reassessment of the risks associated with the electric power industry?

A. Policy evolution in the electric transmission area has been wide-reaching and investors have increasingly focused on uncertainty over operating rules and market development. Virtually all industry stakeholders have recognized that regulatory uncertainties increase the risks associated with the utility industry. For example, the Department of Energy ("DOE") identified "reducing regulatory uncertainty" as critical in stimulating increased investment

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[20] Standard & Poor's Corporation, "Fuel and Power Adjusters Underpin Post-Crisis Credit Quality of Western U.S. Utilities," *Utilities & Perspectives* (Oct. 18, 2004).

[21] FitchRatings, "Outlook 2005: U.S. Power & Gas," *Global Power/North America Special Report* (Jan. 6, 2005) at 26.

in the power industry and noted that lack of clarity in the regulatory structure was inhibiting planning and investment.[23] The DOE also recognized the impact that this regulatory uncertainty has on investors' required rates of return for electric utilities:

> Because transmission assets are long lived, regulatory uncertainty increases the risks to investors and, therefore, increases the returns they need to justify transmission system investments.[24]

The Wall Street Journal cited the debilitating impact of an "unsteady regulatory situation" and the "chaotic combination of regulated and deregulated markets" in explaining inhibitions to increased investment in the electric utility system.[25] Similarly, S&P warned investors that the partial reforms presently characterizing wholesale power markets invite prolonged dysfunction and that elevated risks will discourage new capital, "or at least make it more expensive."[26]

Investors recognize the potential for ongoing market volatility and remain sensitive to the strain such events can imply for regulated utilities. Investors are mindful that, even when regulation is supportive and market conditions appear relatively stable, unexpected events can trigger rapid financial deterioration before regulatory authorities are able to react.

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[22] FitchRatings, "U.S. Electric Utilities: Credit Implications of Commodity Cost Recovery," *Global Power/North America Special Report* (Feb. 13, 2006).
[23] U.S. Department of Energy, *National Transmission Grid Study* (May 2002), at 24 and 31.
[24] *Id.* at 31.
[25] Smith, Rebecca, "Overloaded Circuits: Blackout Signals Major Weakness in U.S. Power Grid," The Wall Street Journal (Aug. 18, 2003).
[26] Standard & Poor's Corporation, "Electric Utility Blackouts Put Spotlight on Political and Regulatory Credit Risk," *RatingsDirect* (Aug. 21, 2003).

Q. Are investors likely to consider the impact of these market conditions in assessing their required rate of return for Black Hills?

A. Absolutely. While utility restructuring has not been actively pursued in South Dakota, Black Hills continues to face the prospect of FERC driven changes in the electric transmission function of their business, with other fundamental market trends and industry reforms continuing to impact Black Hills and its investors. Already, Western utilities have confronted the uncertainties associated with the establishment of regional transmission organizations through the numerous regulatory and legal proceedings. Moreover, potential exposure to wholesale energy markets magnifies the importance of maintaining the financial flexibility necessary to fund an adequate and reliable utility system, especially for utilities located in the West. These challenges posed by an increasingly complex marketplace heighten the uncertainties associated with Black Hills' utility operations while requiring the commitment of significant new capital investment to maintain and enhance service capabilities. Thus, while restructuring has not been implemented for Black Hills' service territory, investors undoubtedly consider these factors in assessing the required rate of return on long-term capital, such as common equity.

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

A. No. Apart from these factors, the industry continues to face the normal risks inherent in operating electric utility systems, including the potential adverse effects of inflation, interest rate changes, growth, the general economy, and regulatory uncertainty and lag. As a senior Fitch analyst recently noted:

> Capital expenditures are on the rise for network reliability, mandated environmental compliance, and resource adequacy. Utilities face rising non-fuel operating and maintenance expenses, particularly for pensions, employee medical expenses, and post-retirement benefits. A trend of

> declining interest expenses that benefited the sector over the past four years is likely to reverse in the next several years. … In Fitch's view, the sector's credit recovery is now fading, and investors should exercise greater caution regarding the power and gas sector.[27]

C. Risk and Firm Size

Q. Do investors consider Black Hills' relative size in their assessment of the Company's risks and prospects?

A. Yes. A firm's relative size has important implications for investors in their evaluation of alternative investments, and because Black Hills is a wholly owned subsidiary, the relevant benchmark for common shareholders is the Company's parent corporation, Black Hills Corp. With a market capitalization of approximately $1.1 billion, Black Hills Corp. is one of the smallest publicly traded electric utility holding companies followed by the Value Line Investment Survey ("Value Line"). Indeed, the average capitalization of the 60 electric utility holding companies followed by Value Line is approximately $6.8 billion, with Black Hills Corp.'s small-cap status placing it within the ninth decile of this industry group.[28]

Q. How does Black Hills' position as one of the smallest utilities followed by Value Line affect investors' risk perceptions?

A. The magnitude of the size disparity between Black Hills' parent and other firms in the electric utility industry has important practical implications with respect to the risks faced by investors. All else being equal, it is well accepted that smaller firms are more risky than their larger counterparts, due in part to their relative lack of diversification and lower financial resiliency. In the case of a smaller utility, its earnings are principally dependent on

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[27] Lapson, Ellen, "Rising Unit Costs & Credit Quality: Warning Signals," Public Utilities Fortnightly (Feb. 1, 2006).
[28] www.valueline.com (Retrieved May 29, 2006).

the economic, social, regulatory, and other factors affecting a more limited constituency. This can result in significant exposure, especially where key employers or industries dominate the economy.

Additionally, due to the lower density and other characteristics of its service territory, a smaller utility serving more sparsely populated rural areas generally incurs higher investment and expenses per customer than is typical for other electric providers. Meanwhile, larger electric utilities generally enjoy improved exposure to financial markets, which enhances their ability to raise additional capital relative to smaller utilities. As a result, they are better prepared to withstand adverse events and possess greater financial flexibility to respond or adapt to changing market conditions, such as those that currently confront the electric utility industry.

Q. Is there empirical evidence in the financial literature that a company's size affects its relative risks?

A. Yes. It is well established in the financial literature that smaller firms are more risky than larger firms. [29] For example, a classic University of Kansas study demonstrated that large firms are assigned higher bond ratings than small firms with similar characteristics,[30] and there is ample empirical evidence that investors in smaller firms realize higher rates of return than ~~in~~ larger firms.[31] Common sense and accepted financial doctrine hold that investors require higher returns from smaller companies, and unless that compensation is

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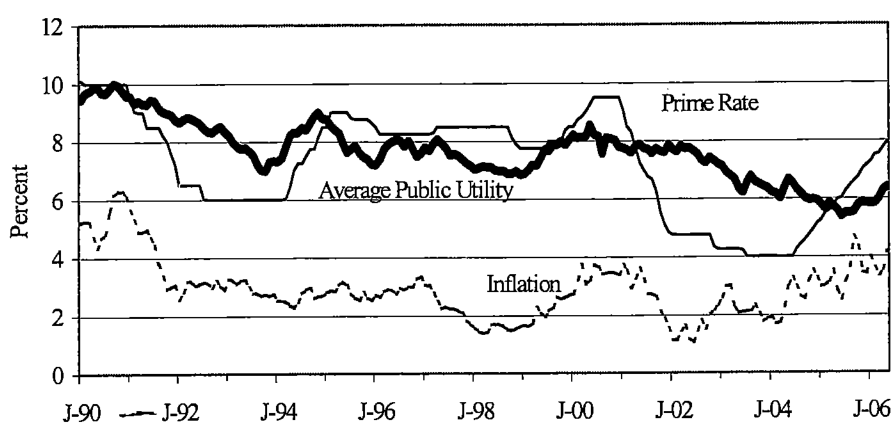
[29] See, *e.g.*, Eugene F. Fama and Kenneth R. French, "The Cross-Section of Expected Stock Returns", *The Journal of Finance* (June 1992).
[30] George E. Pinches, J. Clay Singleton, and Ali Jahankhani, "Fixed Coverage as a Determinant of Electric Utility Bond Ratings", *Financial Management* (Summer 1978).
[31] See for example Rolf W. Banz, "The Relationship Between Return and Market Value of Common Stocks", *Journal of Financial Economics* (September 1981) at 16.

provided in the rate of return allowed for a utility, the legal tests embodied in the *Hope* and *Bluefield* cases cannot be met.

D. Economy and Capital Markets

Q. Please describe recent historical trends in bond yields.

A. Average long-term public utility bond rates, the monthly average prime rate, and inflation as measured by the consumer price index since 1990 are plotted in the graph below. After rising to approximately 10% in mid-1990, the average yield on long-term public utility bonds generally fell as economic conditions weakened in the aftermath of the 1991 Gulf war, with rates dipping below 7% in late 1993. Yields subsequently rose again in 1994, before beginning a general decline. More recently, interest rates have trended upward, with investors requiring approximately 6.4% from average public utility bonds in May 2006:



Q. Are investors likely to anticipate any substantial decline in interest rates going forward?

A. No. On May 10, 2006 the Federal Reserve Board ("Fed") raised interest rates for the sixteenth time since June 2004. The latest quarter-point increase raised the target discount rate to 5.00%, or five times the 46-year low of 1.00% in effect when the Fed began its credit-tightening campaign in 2004. As Value Line noted, the investment community's general expectation is that interest rates will continue to rise in the short-run as the Fed nears the end of its tightening cycle.[32] With growing inflationary worries, investors are concerned that the Fed will continue its aggressive stance:

> Since late last year, investors have been increasingly uncertain about the Federal Reserve's plan to prevent the economy from overheating and fight inflation by gently nudging short-term rates higher. But while economic growth recently has shown signs of moderating, soaring commodity prices still pose a threat to prices elsewhere in the economy. … Fed Chairman Ben Bernanke has made it clear the Fed will keep lifting rates even at the risk of stunting growth. That's prompted the market to worry that the central bank could overshoot its target and trigger an economic slide.[33]

Consistent with the general expectations that the Fed's actions will also translate into higher long-term bond yields, the most recent forecast of GlobalInsight, a widely referenced forecasting service, calls for double-A public utility bond yields to reach 6.27% in 2007 and average 6.92% over the next five years.[34] Meanwhile, the Energy Information Administration ("EIA"), a statistical agency of the U.S. Department of Energy, anticipates that the double-A public utility bond yield will reach 6.65% in 2007, or an average of 7.18% for the period 2007-2011.[35] The projections published by Blue Chip Financial Forecasts ("Blue Chip") also anticipate that corporate bond yields will rise approximately 60 basis points through the third quarter of 2007.[36]

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[32] The Value Line Investment Survey, *Selection & Opinion* (Apr. 7, 2006) at 1191.

[33] Wang, Christopher, "Wall Street's Eyes Are on the Fed," Associated Press (Jun. 25, 2006).

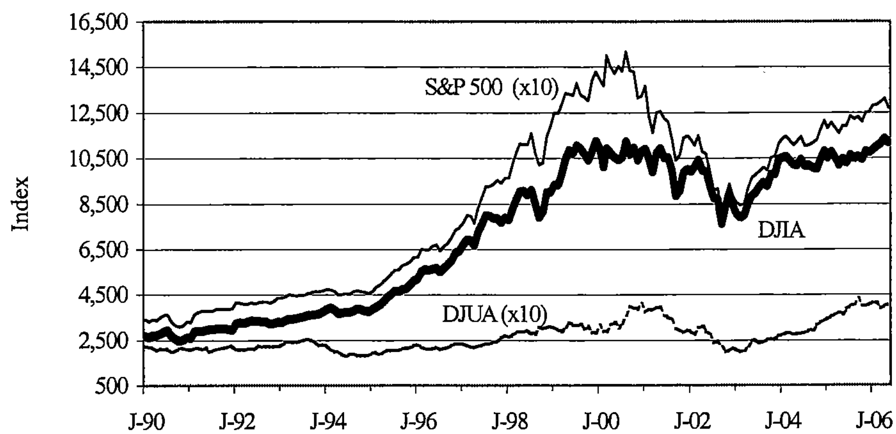
[34] GlobalInsight, "The U.S. Economy: The 30-Year Focus" (First-Quarter 2006) at Table 34. This is the only series of projections for public utility bond yields reported by GlobalInsight.

[35] Energy Information Administration, "Annual Energy Outlook 2006" (Jan. 2006) at Table 19. This is the only series of projections for public utility bond yields reported by EIA.

[36] Blue Chip Financial Forecasts (Apr. 1, 2006) at 2.

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

A. With respect to trends in the market for common equity, between 1990 and early 2000 stock prices pushed steadily higher as the longest bull market in United States history continued unabated. While the S&P 500 had increased over four times in value by August 2000, mounting concerns regarding prospects for future growth, particularly for firms in the high technology sector, pushed equity prices lower, in some cases precipitously. Common stock prices have since recovered strongly from their lows; but the market remains volatile, with share values routinely changing in full percentage points during a single day's trading. The graph below plots the performances of the Dow-Jones Industrial Average, the S&P 500, and the Dow Jones Utility Average since 1990 (the latter two indices were scaled for comparability):



Q. What is the outlook for the United States economy?

A. The economic picture has brightened significantly since the downturn that began in 2001. Real gross domestic product ("GDP") expanded at a rate of 5.3% in the first quarter of

2006, after increasing 1.7% in the fourth quarter of 2005.[37] Nevertheless, uncertainties over the durability and pace of economic growth continue to be impacted by overhanging government and trade deficits and higher energy prices. Continued conflict and instability in Iraq and the ongoing threat of terrorism also undermine consumer confidence and contribute to global economic uncertainty. These factors cause the outlook to remain tenuous, with persistent stock and bond price volatility providing tangible evidence of the uncertainties faced by the United States economy.

Q. How do these economic uncertainties affect electric utilities?

A. Uncertainties over the durability of the economic recovery have combined to heighten the risks faced by utilities. Stagnant economic growth would undoubtedly mean flat sales, while the potential for higher inflation and interest rates would place additional pressure on the adequacy of existing service rates. Meanwhile, continued conflict and instability in the Middle East, coupled with the aftermath of hurricanes Katrina and Rita, intensifies concerns over prolonged volatility in oil and gas prices. While the economy may ultimately return to a path of steady growth and the volatility in the capital and energy markets may abate, the underlying weaknesses now present cause considerable uncertainties to persist, which increase the risks faced by the utility industry.

III. CAPITAL MARKET ESTIMATES

Q. What is the purpose of this section?

A. In this section, capital market estimates of the cost of equity are developed for a benchmark group of electric utilities. First, I examine the concept of the cost of equity, along with the

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[37] Bureau of Economic Analysis, "GDP Growth Revised Up in First Quarter," *News Release* (May. 25, 2006).

risk-return tradeoff principle fundamental to capital markets. Next, I describe DCF, risk premium, and comparable earnings analyses conducted to estimate the cost of equity for the reference group of electric utilities. Finally, I examine other factors (*i.e.*, flotation costs) properly considered in evaluating a fair rate of return on equity.

A. Economic Standards

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. Competition for investor funds is intense and investors are free to invest their funds wherever they choose. They 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 service while meeting the needs of customers through necessary system expansion.

Q. What fundamental economic principle underlies this cost of equity concept?

A. Unlike debt capital, there is no contractually guaranteed return on common equity capital since shareholders are the residual owners of the utility. Nonetheless, common equity investors still require a return on their investment, with the cost of equity being the minimum "rent" that must be paid for the use of their money. This cost of equity typically serves as the starting point for determining a fair rate of return on common equity.

The cost of equity concept is predicated on the notion that investors are risk averse, and will willingly bear additional risk only if they expect compensation for doing so. In capital markets where relatively risk-free assets are available (*e.g.*, U.S. Treasury securities) 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 market data and generally accepted measures of risk exist. Bond yields, for example, reflect investors' expected rates of return, and bond ratings measure the risk of individual bond issues. The observed yields on federal government securities, which are considered free of default risk, and bonds of various rating categories demonstrate that the risk-return tradeoff does, in fact, exist in the capital markets.

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

A. It is generally accepted that the risk-return tradeoff evidenced with long-term debt extends to all assets. However, documenting the risk-return tradeoff for assets other than fixed income securities is complicated by two factors. First, there is no standard measure of risk applicable to all assets. Second, for most assets – including common stock – required rates of return cannot be directly observed. Nevertheless, it is a fundamental tenet that investors exhibit risk aversion in deciding whether or not to hold common stocks and other assets, just as when choosing among fixed income securities. This has been supported and demonstrated by considerable empirical research in the field of finance and is confirmed by reference to historical earned rates of return, with realized rates of return on common stocks exceeding those on government and corporate bonds over the long-term.

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

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

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

While the rights of preferred stockholders to available cash flow for these payments are junior to creditors, and preferred stockholders cannot compel bankruptcy, their claims are senior to those of common shareholders.

The last investors in line are common shareholders. They receive only the cash flow, if any, that remains after all other claimants – employees, suppliers, governments, lenders, and preferred stockholders – have been paid. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, is considerably higher than the yield on the utility's long-term debt or preferred stock, which have more certain, senior claims.

Q. What does the above discussion imply with respect to estimating the cost of equity?

A. Although the cost of equity cannot be observed directly, it is a function of the returns available from other investment alternatives and the risks to which the equity capital is exposed. 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' required rates of return. These various quantitative methods typically attempt to infer investors' required rates of return from stock prices, interest rates, and other capital market data.

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

A. No. In my opinion, no single method or model should be relied upon to determine 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. Instead, we conclude that we should adopt a more accommodating and flexible position.[38]

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

B. Discounted Cash Flow Analyses

Q. How are DCF models used to estimate the cost of equity?

A. The use of DCF models is essentially an attempt to replicate the market valuation process that sets the price investors are willing to pay for a share of a company's stock. The model rests on the assumption that investors evaluate the risks and expected rates of return from all securities in the capital markets. Given these expected rates of return, the price of each stock is adjusted by the market until investors are adequately compensated for the risks they bear. Therefore, we can look to the market to determine what investors believe a share of common stock is worth. By estimating the cash flows investors expect to receive from the stock in the way of future dividends and capital gains, we can calculate their required rate of return. In other words, the cash flows that investors expect from a stock are estimated,

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

and given its current market price, we can "back-into" the discount rate, or cost of equity, that investors implicity used in bidding the stock to that price.

Q. What market valuation process underlies DCF models?

A. DCF models are derived from a theory of valuation which assumes that the price of a share of common stock is equal to the present value of the expected cash flows (i.e., future dividends and stock price) that will be received while holding the stock, discounted at investors' required rate of return, or the cost of equity. Notationally, the general form of the DCF model is as 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;
- A discount rate exceeding 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.

Q. Are the assumptions underlying the constant growth form of the DCF model met in the real world?

A. In practice, none of the assumptions required to convert the general form of the DCF model to the constant growth form are ever strictly met. Nevertheless, where earnings are derived from stable activities, and earnings, dividends, and book value track fairly closely, the constant growth form of the DCF model offers a reasonable working approximation of stock valuation that provides useful insight as to investors' required rate of return.

Q. How did you implement the DCF model to estimate the cost of equity for Black Hills?

A. In estimating the cost of equity, the DCF model is typically applied to publicly traded firms engaged in similar business activities. In order to reflect the risks and prospects associated with Black Hills' jurisdictional utility operations, my DCF analyses focused on a reference group of other electric utilities composed of those companies included by Value Line in their Electric Utilities (West) Industry group. Excluded from my analyses were four firms that either do not pay common dividends or were rated below investment grade by S&P.

The consolidated corporate credit ratings published by S&P for the individual firms in the electric utility proxy group ranged from "BBB-" to "BBB+", with the average being "BBB". As noted earlier, Black Hills is currently assigned a corporate rating of "BBB-", which corresponds to the very bottom end of the proxy group range and represents the lowest investment grade rating. Given that these eleven utilities are all engaged in utility operations in the Western region of the U.S., investors are likely to regard this group as facing similar market conditions and having comparable risks and prospects. The Supreme Court recognized the relevance of geographical location in *Bluefield,* noting that utilities are entitled to earn a return equal to those being made by firms of comparable risk "in the same general part of the country."[39] Indeed, there are important factors distinguishing Western utilities from ~~those~~ located in other regions, such as the ongoing uncertainties associated with Western energy markets, that are important considerations in evaluating investors' required rate of return for Black Hills.

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[39] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n,* 262 U.S. 679, 692 (1923).

Q. Why did you exclude firms that do not pay common dividends or have below investment grade bond ratings from your proxy group?

A. As discussed earlier, under the DCF approach, observable stock prices are a function of the cash flows that investors expect to receive, discounted at their required rate of return. Because dividend payments are a key parameter required to apply the DCF method, this hinders application of the DCF model to firms that do not pay common dividends. Meanwhile, the financial stress and lack of stability that accompanies below investment grade bond ratings violates the comparable-risk standard and greatly complicates any determination of investors' long-term expectations that form the basis for DCF applications.

Q. What other considerations support the use of a proxy group in estimating the cost of equity for Black Hills?

A. Apart from recognizing the inherent risks and prospects for comparable risk utilities, reference to a proxy group of utilities is essential to insulate against vagaries that can result when the stochastic process involved in estimating the cost of equity is applied to a single company. The cost of equity is inherently unobservable and can only be inferred indirectly by reference to available capital market data. If the data used to apply the DCF model does not capture the expectations that investors have incorporated into a company's current stock price, the resulting cost of equity estimate will be biased and fail to reflect investors' required rate of return.

As the FERC has noted even using a limited group of companies does not remove the potential for error:

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

expand the group of proxy companies to determine a zone of reasonableness.[40]

The 11-company proxy group composed of utilities operating in the Western U.S. is consistent not only with shared investment risks, but also with the need to ensure against the potential that a single cost of equity estimate may not reflect investors' required rate of return.

Q. How is the constant growth form of the DCF model typically used to estimate the cost of equity?

A. The first step in implementing the constant growth DCF model is to determine the expected dividend yield (D_1/P_0) for the firm in question. This is usually calculated based on an estimate of dividends to be paid in the coming year divided by the current price of the stock. The second, and more controversial, step is to estimate investors' long-term growth expectations (*g*) for the firm. The final step is to sum the firm's dividend yield and estimated growth rate to arrive at an estimate of its cost of equity.

Q. How was the dividend yield for the proxy group of electric utilities determined?

A. Estimates of dividends to be paid by each of these electric 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 prices, and resulting dividend yields for the firms in the electric utility proxy group are presented on Exhibit WEA-1. As shown there, dividend yields for the eleven firms in the electric utility proxy group ranged from 2.2% to 5.1%, with the average being 3.7%.

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[40] Federal Energy Regulatory Commission, *Order on Initial Decision* , Docket No. RP00-107-000 (July 3, 2003).

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

A. In constant growth DCF theory, earnings, dividends, book value, and market price are all assumed to grow in lockstep, and the growth horizon of the DCF model is infinite. But implementation of the DCF model is more than just a theoretical exercise; it is an attempt to replicate the mechanism investors used to arrive at observable stock prices. Thus, the only "g" that matters in applying the DCF model is the value that investors expect and have embodied in current market prices.

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

A. No. In response to more accentuated business risks in the industry, electric utilities adopted dividend policies that were much more conservative than in the past. As a result, dividend growth in the electric utility industry has remained largely stagnant in recent years as utilities conserved financial resources to provide a hedge against heightened uncertainties. Responding to this trend, investors' focus increasingly shifted from dividends to earnings as a measure of long-term growth, as payout ratios for firms in the electric utility industry trended downward from approximately 80% historically to on the order of 60%.[41]

Q. What are investors likely expecting in the way of dividend growth for the electric utility proxy group?

A. As the industry recovers from the financial challenges of the last several years, some electric utilities have begun to reevaluate their dividend policies and reinstate increases to their quarterly payout. While investors have recently expressed renewed interest in dividend payments, Value Line's most recent forecast indicates negative projected dividend growth for one of the proxy firms, while one is listed as "Nil" and two others as "NMF".[42] Negative or zero growth rates imply a cost of equity equal to, or below, the utility's dividend yield. Such nonsensical results provide little guidance as to investors' expectations for the electric utility proxy group.

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

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

> [E]arnings, presumably, are the basis for the investment benefits that we all seek. "Healthy 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 future performance.[43]

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%.[44]

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[41] See, *e.g.*, The Value Line Investment Survey (Sep. 15, 1995 at 161, May 12, 2006 at 1774).

[42] The Value Line Investment Survey (May 12, 2006).

[43] Association for Investment Management and Research, "Finding Reality in Reported Earnings: An Overview", p. 1 (Dec. 4, 1996).

[44] The Value Line Investment Survey, *Subscriber's Guide*, p. 53.

The fact that investment advisory services, such as Value Line and I/B/E/S International, Inc. ("IBES"), focus on growth in earnings indicates that the investment community regards this as a superior indicator of future long-term growth. Indeed, "A Study of Financial Analysts: Practice and Theory," published in the *Financial Analysts Journal*, reported the results of a survey conducted to determine what analytical techniques investment analysts actually use.[45] Respondents were asked to rank the relative importance of earnings, dividends, cash flow, and book value in analyzing securities. Of the 297 analysts that responded, only 3 ranked dividends first while 276 ranked it last. The article concluded:

> Earnings and cash flow are considered far more important than book value and dividends.[46]

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

A. The earnings growth projections for each of the firms in the electric utility proxy group reported by IBES and published in S&P's *Earnings Guide* are displayed on Exhibit WEA-2. Also presented are the earnings per share ("EPS") growth projections reported by Value Line, First Call Corporation ("First Call"), Zacks Investment Research ("Zacks"), and Reuters, Inc. ("Reuters"). As shown there, these security analysts' projections suggested growth on the order of 5.7% to 6.5% for the reference group of electric utilities:

[45] Block, Stanley B., "A Study of Financial Analysts: Practice and Theory", *Financial Analysts Journal* (July/August 1999).
[46] *Id.* at 88.

<u>Electric Utility Proxy Group</u>

Service	Growth Rate
IBES	6.3%
Value Line	5.7%
First Call	5.9%
Zacks	6.5%
Reuters	6.2%

In addition, First Call reported average growth expectations for its Electric Utilities industry group of 6.69%,[47] while Zacks indicated an overall expected growth rate for the Electric Power industry of 8.40%.[48]

Q. What considerations are relevant in evaluating these near-term growth rates for electric utilities?

A. Short-term projected growth rates may be colored by lingering uncertainties regarding the near-term direction of the economy in general and the numerous challenges recently faced in the electric power industry specifically. This short-term "hangover" is exemplified by Value Line, which has assigned its Utilities sector the lowest ranking of all 10 sectors it covers for year-ahead stock price performance,[49] while noting that "[t]he electric utility industry carries a Below-Average industry Timeliness rank."[50] While this cautious outlook may be indicative of relatively low near-term growth projections, it does not necessarily reflect investors' long-term expectations for the industry.

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[47] http://finance.yahoo.com (Retrieved May 22, 2006).
[48] Zacks Investment Research, http://www.zacks.com/ (Retrieved May 22, 2006).
[49] The Value Line Investment Survey, *Selection & Opinion* (Feb. 3, 2006) at 1303.
[50] The Value Line Investment Survey (March 31, 2006) at 695.

Q. How else are investors' expectations of future long-term growth prospects often estimated for use in the constant growth DCF model?

A. Based on the assumptions underlying constant growth theory, conventional applications of the constant growth DCF model often examine the relationship 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 the 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. This increase to the book value of existing shareholders leads to higher expected earnings and dividends, with the "sv" factor incorporating this additional growth component.

Q. What growth ~~rate~~ does the earnings retention method suggest for the proxy group of electric utilities?

A. The sustainable, "br+sv" growth rates for each firm in the proxy group are shown on Exhibit WEA-3. For each firm, the expected retention ratio (b) was calculated based on Value Line's projected dividends and earnings per share. Likewise, each firm's expected earned rate of return (r) was computed by dividing projected earnings per share by projected net book value. Because Value Line reports end-of-year book values, an adjustment was incorporated to compute an average rate of return over the year, consistent with the theory underlying this approach to estimating investors' growth expectations. Meanwhile, the percent of common equity expected to be issued annually as new common stock (s) was equal to the product of the projected market-to-book ratio and growth in common shares outstanding, while the equity accretion rate (v) was computed as 1 minus the inverse of the projected market-to-book ratio. As shown there, incorporating this method resulted in an average expected growth rate for the group of electric utilities of 5.2%.

Q. What did you conclude with respect to the growth expectations implied for the proxy group of Western electric utilities?

A. Considering expectations for the industry in general and the relatively cautious nature of short-term projections for the proxy firms, I concluded that the measures discussed above suggested a long-term DCF growth rate on the order of 6.5% for the Western electric utility group.

Q. What cost of equity was implied for the proxy group of utilities using the DCF model?

A. Combining the 3.7% average dividend yield with a growth rate of 6.5% implied a DCF cost of equity of 10.2%.

Q. Do you believe this single DCF result should be relied on exclusively to evaluate a reasonable ROE for the proxy group of electric utilities or Black Hills?

A. No. Because the cost of equity is unobservable, no single method should be viewed in isolation. While the DCF model has been routinely relied on in regulatory proceedings as one guide to investors' required return, it is a blunt tool that should never be used exclusively, and regulators have customarily considered the results of alternative approaches in determining allowed returns. The need to consider alternative methods is especially important where the results of one approach deviate significantly from cost of equity estimates produced by other applications. Indeed, as discussed subsequently, the results of alternative risk premium methods and the comparable earnings approach suggest a cost of equity far in excess of this single DCF value.

Moreover, as noted earlier, the short-term projected growth rates typically used to apply the DCF model may be colored by lingering economic and industry uncertainties, as exemplified by Value Line's pessimistic near-term rankings for the utility sector generally, and electric utilities specifically. As a result of this cautious near-term outlook, DCF growth rates do not necessarily capture investors' long-term expectations for the industry, and the resulting cost of equity estimates will be downward-biased. Accordingly, it would be unreasonable to establish an ROE based only on this single DCF result.

C. Risk Premium Analyses

Q. What other analyses did you conduct to estimate the cost of equity?

A. As I mentioned previously, because the cost of equity is inherently unobservable, no single method should be considered a reliable guide to investors' required rate of return. Accordingly, I also evaluated the cost of equity for Black Hills using the risk premium method. My applications of the risk premium method provide alternative approaches to measure equity risk premiums that focus specifically on data for electric utilities and employ alternative estimates of investors' required rates of return.

Q. Briefly describe the risk premium method.

A. The risk premium method of estimating investors' required rate of return extends the risk-return tradeoff observed with bonds to common stocks. The cost of equity is estimated by first determining the additional return investors require to forego the relative safety of bonds and to bear the greater risks associated with common stock, and then adding this equity risk premium to the current yield on bonds. Like the DCF model, the risk premium method is capital market oriented. However, unlike DCF models, which indirectly impute the cost of equity, the risk premium method directly estimates investors' required rate of return by adding an equity risk premium to observable bond yields.

Q. How did you implement the risk premium method?

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

Authorized returns presumably reflect regulatory commissions' best estimates of the cost of equity, however determined, at the time they issued their final order. Moreover, allowed returns are an important consideration for investors and have the potential to influence other observable investment parameters, including credit ratings and borrowing costs. Thus, this data provides a logical and frequently referenced basis for estimating equity risk premiums.

Under the realized-rate-of-return approach, equity risk premiums are calculated by measuring the rate of return (including dividends, interest, and capital gains and losses) actually realized on an investment in common stocks and bonds over historical periods.

The realized rate of return on bonds is then subtracted from the return earned on common stocks to measure equity risk premiums.

The CAPM approach, which is routinely referenced in the financial literature and in regulatory proceedings, measures the market-expected return for a security as the sum of a risk-free rate and a risk premium based on the portion of a security's risk that cannot be eliminated by holding a well-diversified portfolio. Under the CAPM, risk is represented by the beta coefficient (β), which measures the volatility of a security's price relative to the market as a whole.

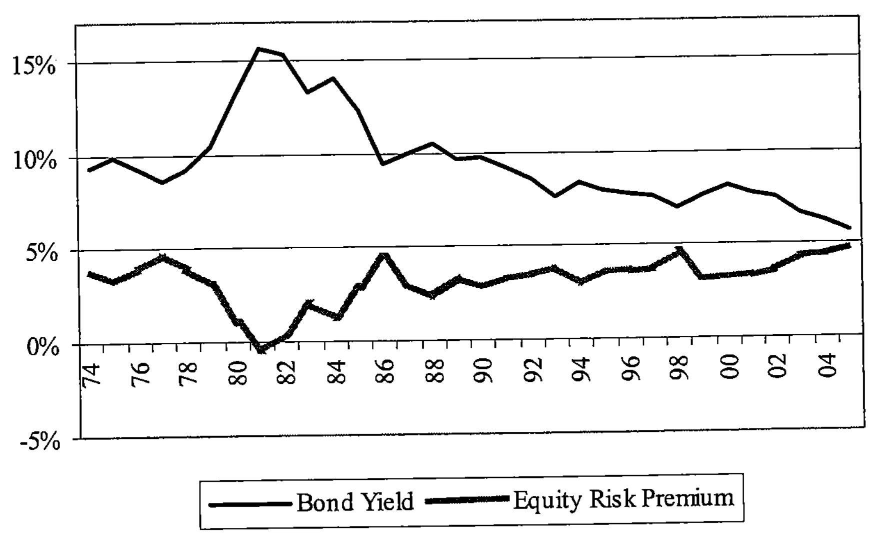
While these methods are premised on different assumptions, each having their own strengths and weaknesses, they are widely accepted approaches that have been routinely referenced in estimating the cost of equity for regulated utilities.

Q. **How did you implement the risk premium method using surveys of allowed rates of return?**

A. Surveys of previously authorized rates of return on common equity are frequently referenced as the basis for estimating equity risk premiums. The rates of return on common equity authorized utilities by regulatory commissions across the U.S. are compiled by Regulatory Research Associates ("RRA") and published in its Regulatory Focus report. In Exhibit WEA-4, the average yield on public utility bonds is subtracted from the average allowed rate of return on common equity for electric utilities to calculate equity risk premiums for each year between 1974 and 2005. Over this period, these equity risk premiums for electric utilities averaged 3.22%, and the yield on public utility bonds averaged 9.46%.

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

A. Yes. There is considerable evidence that the magnitude of equity risk premiums is not constant and that equity risk premiums tend to move inversely with interest rates. In other words, when interest rate levels are relatively high, equity risk premiums narrow, and when interest rates are relatively low, equity risk premiums widen. To illustrate, the graph below plots the yields on public utility bonds (solid line) and equity risk premiums (shaded line) shown on Exhibit WEA-4:



The graph clearly illustrates that the higher the level of interest rates, the lower the equity risk premium, and vice versa. The implication of this inverse relationship is that the cost of equity does not move as much as, or in lockstep with, interest rates. Accordingly, for a 1% increase or decrease in interest rates, the cost of equity may only rise or fall, say, 50 basis points. Therefore, when implementing the risk premium method, adjustments may be required to incorporate this inverse relationship if current interest rate levels have changed since the equity risk premiums were estimated.

Q. What cost of equity is implied by surveys of allowed rates of return on equity?

A. Based on a regression analysis between the interest rates and equity risk premiums presented on Exhibit WEA-4, the equity risk premium for electric utilities increased approximately 43 basis points for each percentage point drop in the yield on average public utility bonds.[51] As illustrated there, with the average yield on public utility bonds in May 2006 being 6.39%, this implied a current equity risk premium of 4.54% for electric utilities. Adding this equity risk premium to the May 2006 average yield on triple-B public utility bonds of 6.59% produces a current cost of equity for the utilities in the benchmark group of approximately 11.1%.

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

A. As discussed earlier, there is widespread consensus that interest rates will continue to increase, with the Fed's recent actions indicative of tighter credit conditions and higher long-term interest rates in the years ahead. As a result, current public utility bond yields are likely to understate capital market requirements at the time the outcome of this proceeding becomes effective. Accordingly, in addition to the use of current bond yields, I also applied the alternative risk premium methods using forecasted bond yields for 2007, based on an average of the projections published by GlobalInsight, EIA, and Blue Chip.[52]

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[51] The average public utility bond yield reflects the average of the yields for bonds rated "Aa", "A", and "Baa" by Moody's.

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

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

A. As shown on page 2 of Exhibit WEA-4, incorporating a forecasted yield for 2007 and adjusting for changes in interest rates since the study period implied an equity risk premium of 4.45% for electric utilities. Adding this equity risk premium to the implied yield on triple-B public utility bonds for 2007 of 6.9% resulted in an implied cost of equity of approximately 11.4%.

Q. How did you apply the realized-rate-of-return approach?

A. Widely used in academia, the realized-rate-of-return approach is based on the assumption that, given a sufficiently large number of observations over long historical periods, average realized market rates of return will converge to investors' required rates of return. From a more practical perspective, investors may base their expectations for the future on, or may have come to expect that they will earn, rates of return corresponding to those realized in the past. Indeed, average realized rates of return for historical periods are widely reported to investors in the financial press and by investment advisory services as a guide to future performance. By focusing on data for utilities specifically, my realized rate of return approach avoided the need to make assumptions regarding relative risk (*e.g.*, beta) that are often embodie~~d-~~in applications of this method.

Stock price and dividend data for the electric utilities included in the S&P 500 Composite Index ("S&P 500") are available for the period 1946 through 2005. As shown in Exhibit WEA-5, over this period realized rates of return for these utilities have exceeded those on average public utility bonds by an average of 4.14%. In contrast to other risk premium approaches, the realized-rate-of-return method assumes that equity risk premiums are stationary over time; therefore, no adjustment for the inverse relationship between equity risk premiums and interest rates was made. Adding this 4.14% equity risk premium to the May 2006 yield of 6.59% on triple-B public utility bonds produces a current cost of equity for the electric utility proxy group of approximately 10.7%.

Once again, however, this does not consider the anticipated increase in bond yields through 2007. Adding this 4.14% equity risk premium to the 6.9% forecasted yield on triple-B public utility bonds for 2007 implies a cost of equity of approximately 11.0%.

Q. Please describe your application of the CAPM.

A. The CAPM is a theory of market equilibrium that measures risk using the beta coefficient. Under the CAPM, investors are assumed to be fully diversified, so the 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 stock's price to follow changes in the market. A stock that tends to respond relatively 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 rate of 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 eleven companies in the electric 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-6. Rather than using historical data, the expected market rate of return was estimated by conducting a DCF analysis on the dividend paying firms in the S&P 500. As discussed in greater detail subsequently, it is well accepted that smaller firms are more risky than their larger counterparts. Accordingly, I included only those companies with total market capital exceeding $1.7 billion, which corresponds to the top five size deciles for publicly traded firms.[53]

The dividend yield for each firm was obtained from Value Line, with the growth rate being equal to the average of the earnings growth projections for each company published by IBES and Value Line, with each firm's dividend yield and growth rate being weighted by its proportionate share of total market value.[54] Based on the weighted average of the projections for the 358 individual firms, current estimates imply an average growth rate over the next five years of 11.8%. Combining this average growth rate with a dividend yield of 1.8% results in a current cost of equity estimate for the market as a whole of approximately 13.6%. Subtracting a 5.3% risk-free rate based on the May 2006 average yield on 20-year Treasury bonds from the 13.6% forward-looking rate of return produced a market equity risk premium of 8.3%. Multiplying this risk premium by the average Value Line beta of 0.95 for the utilities in the proxy group, and then adding the resulting 7.9% risk

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[53] Ibbotson Associates, *2006 Yearbook* at 131.

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

premium to the May 2006 average long-term Treasury bond yield, resulted in a current cost of equity of approximately 13.2%.[55]

Q. What other CAPM analyses did you conduct to estimate the cost of equity?

A. I also applied the CAPM using risk premiums based on historical realized rates of return. This approach to estimating investors' equity risk premiums is premised on the assumption that, given a sufficiently large number of observations over long, historical periods, average realized market rates of return will converge to investors' required rates of return.

Q. What CAPM cost of equity is produced based on historical realized rates of return for stocks and long-term government bonds?

A. I applied the CAPM using data published by Ibbotson Associates, which is perhaps the most exhaustive and widely referenced annual study of realized rates of return. Application of the CAPM based on historical realized rates of return is presented in Exhibit WEA-7. In their *2006 Yearbook, Valuation Edition*, Ibbotson Associates reported that, over the period from 1926 through 2005, the arithmetic mean realized rate of return on the S&P 500 exceeded that on long-term government bonds by 7.1%.[56] Multiplying this historical market risk premium by the average Value Line beta of 0.95 produced an equity risk premium of 6.7% for the electric utility proxy group. As shown on page 1 of Exhibit WEA-

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[55] In response to the Fed's credit tightening campaign, long-term Treasury bond yields have increased significantly in recent months. Because present yields are now largely consistent with year-ahead forecasts, no separate CAPM analysis was conducted using projected bond yields.

[56] 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 [*2006 Yearbook, Valuation Edition* at 77]:

> 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.

7, adding this equity risk premium to the May 2006 average yield on 20-year Treasury bonds of 5.3% resulted in an implied cost of equity of 12.0%.

Q. What else should be considered in evaluating the results of the CAPM using historical realized rates of return?

A. The CAPM model, like the DCF approach, is an *ex-ante,* or forward-looking model based on expectations of the future. As a result, in order to accurately estimate required returns the CAPM must be applied using data that reflects the expectations of actual investors. While reference to historical data represents one way to apply the CAPM, these realized rates of return reflect, at best, an indirect estimate of investors' current requirements. As a result, forward-looking applications of the CAPM that look directly at investors' expectations in the capital markets are apt to provide a more meaningful guide to investors' required rate of return. Accordingly, because the historical approach does not incorporate forward-looking estimates, it was given less weight in arriving at my recommended return on equity.

D. Comparable Earnings Method

Q. What other analyses did you conduct to estimate the cost of equity?

A. As I noted earlier, I also evaluated the cost of equity using the comparable earnings method. Reference to rates of return available from alternative investments of comparable risk can provide an important benchmark in assessing the return necessary to assure confidence in the financial integrity of a firm and its ability to attract capital. This comparable earnings approach is consistent with the economic underpinnings for a fair rate of return established by the Supreme Court. Moreover, it avoids the complexities and limitations of capital market methods and instead focuses on the returns earned on book equity, which are readily available to investors.

Q. What rates of return on equity are indicated for utilities based on this approach?

A. With respect to expectations for electric utilities specifically, the most recent edition of Value Line reports that its analysts anticipate an average rate of return on common equity for the electric utility industry of 13.0% in 2006 and 2007, and 12.5% over its three-to-five year forecast horizon.[57] Meanwhile, Value Line expects that natural gas distribution utilities will earn an average rate of return on common equity of 11.0 in 2006, 11.5% in 2007, and 12.0% over the years 2009 through 2011.[58]

Q. Can the comparable earnings method be applied to other firms of similar risk?

A. Yes. Under the regulatory standards established by *Hope* and *Bluefield*, the salient criteria in establishing a meaningful benchmark to evaluate a fair rate of return is relative risk, not the particular business activity or degree of regulation. Utilities must compete for capital, not just against firms in their own industry, but with other investment opportunities of comparable risk. Consistent with this accepted regulatory standard, I also applied the comparable earnings approach based on a reference group of companies in the unregulated sector of the economy.

My assessment of comparable risk relied on two objective benchmarks for the risks associated with common stocks -- Value Line's Safety Rank and beta. The Safety Rank, which ranges from "1" (Safest) to "5" (Riskiest), is intended to capture the total risk of a stock, and incorporates elements of stock price stability and financial strength. As

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[57] The Value Line Investment Survey (Jun. 2, 2006) at 156.
[58] The Value Line Investment Survey (Jun. 16, 2006) at 458.

discussed earlier, Value Line's beta values provide a measure of stock price variability as compared with the firms in the New York Stock Exchange Composite Index, with a beta less than 1.0 indicating that a stock tends to fluctuate less than the market as a whole (lower risk) while a beta greater than 1.0 indicates that the stock tends to fluctuate more than the market (greater risk).

The Value Line Safety Rankings for the firms in the proxy group range from "1" to "3", with beta values for the eleven electric utilities averaging 0.95. Accordingly, my reference group was composed of those U.S. companies followed by Value Line that 1) pay common dividends, 2) have a Safety Rank of "3" or above, and 3) have beta values between 0.90 and 1.00. Consistent with the criteria used to apply the forward-looking CAPM, I included only those firms with a market capitalization greater than $1.7 billion. Value Line's projections indicate that its analysts expect that rates of return on shareholders' equity for the resulting group of 178 firms will average 17.4%, with the median being 15.5%.[59]

Q. What return on equity is indicated by the results of the comparable earnings approach?

A. Based on the results discussed above, I concluded that the comparable earnings approach implies a fair rate of return on equity of at least 11.5% to 12.5%.

E. Proxy Group Cost of Equity Estimates

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

A. The cost of equity estimates implied by my quantitative analyses are summarized below:

Method	Cost of Equity Estimate
DCF	10.2%
Risk Premium	
Authorized Returns	
Current Estimate	11.1%
2007 Estimate	11.4%
Realized Rates of Return	
Current Estimate	10.7%
2007 Estimate	11.0%
CAPM - Forward-looking	13.2%
CAPM – Historical	12.0%
Comparable Earnings	11.5% - 12.5%

In light of anticipated capital market trends and the recent challenges experienced in the electric utility industry, caution should be exercised in interpreting the results of the DCF model and historical risk premium applications. As noted earlier, the single constant growth DCF result is out of line with the preponderance of estimates produced by the risk premium and comparable earnings approaches and should not be viewed in isolation, especially considering the potential for downward bias when DCF growth rates do not capture investors' long-term expectations. Moreover, it is important to recognize that the historical focus of the risk premium studies almost certainly ensures that they fail to fully capture the significantly greater risks that investors now associate with providing electric utility service. As a result, they are likely to understate the cost of equity for a firm operating in today's electric power industry. Finally, expectations for higher public utility bond yields suggest that 2007 estimates should receive more weight. Accordingly, based on the results of my quantitative analyses, and my assessment of the relative strengths and

[59] www.valueline.com (Retrieved May 26, 2006).

weaknesses inherent in each method, I concluded that the cost of equity for the electric utility proxy group is in the 11.0% to 12.0% range.

F. Flotation Costs

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

A. The common equity used to finance the investment in utility assets is provided from either the sale of stock in the capital markets or from retained earnings not paid out as dividends. When equity is raised through the sale of common stock, there are costs associated with "floating" the new equity securities. These flotation costs include services such as legal, accounting, and printing, as well as the fees and discounts paid to compensate brokers for selling the stock to the public. Also, some argue that the "market pressure" from the additional supply of common stock and other market factors may further reduce the amount of funds a utility nets when it issues common equity.

Q. Is there an established mechanism for a utility to recognize equity issuance costs?

A. No. While debt flotation costs are recorded on the books of the utility, amortized over the life of the issue, and thus increase the effective cost of debt capital, there is no similar accounting treatment to ensure that equity flotation costs are recorded and ultimately recognized. Alternatively, no rate of return is authorized on flotation costs necessarily incurred to obtain a portion of the equity capital used to finance plant. In other words, 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. 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.[60]

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%.[61]

Applying these expense percentages to a representative dividend yield for a utility of 3.7% implies a flotation cost adjustment on the order of 13 to 37 basis points.

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[60] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," Public Utility Reports (1994) at 166.

[61] *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%.

Q. Is the need for a flotation cost adjustment to compensate for past equity issues recognized in the financial literature?

A. Yes. In a *Public Utilities Fortnightly* article, Brigham, Aberwald, and Gapenski demonstrated that even if no further stock issues are contemplated, a flotation cost adjustment in all future years is required to keep shareholders whole, and that the flotation cost adjustment must consider total equity, including retained earnings.[62] Similarly, *Regulatory Finance: Utilities' Cost of Capital* contains the following discussion:

> Another controversy is whether the underpricing allowance should still be applied when the utility is not contemplating an imminent common stock issue. Some argue that flotation costs are real and should be recognized in calculating the fair rate of return on equity, but only at the time when the expenses are incurred. In other words, the flotation cost allowance should not continue indefinitely, but should be made in the year in which the sale of securities occurs, with no need for continuing compensation in future years. This argument implies that the company has already been compensated for these costs and/or the initial contributed capital was obtained freely, devoid of any flotation costs, which is an unlikely assumption, and certainly not applicable to most utilities. ... The flotation cost adjustment cannot be strictly forward-looking unless all past flotation costs associated with past issues have been recovered.[63]

Q. Can you provide a simple numerical example illustrating why a flotation cost adjustment is necessary to account for past flotation costs?

A. Yes. The following example demonstrates that investors will not have the opportunity to earn their required rate of return (*i.e.*, dividend yield plus expected growth) unless an allowance for past flotation costs is included in the allowed rate of return on equity. Assume a utility sells $10 worth of common stock at the beginning of year 1. If the utility incurs flotation costs of $0.48 (5% of the net proceeds), then only $9.52 is available to

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[62] Brigham, E.F., Aberwald, D.A., and Gapenski, L.C., "Common Equity Flotation Costs and Rate Making," *Public Utilities Fortnightly* (May, 2, 1985).

invest in rate base. Assume that common shareholders' required rate of return is 11.5%, the expected dividend in year 1 is $0.50 (*i.e.*, a dividend yield of 5%), and that growth is expected to be 6.5% annually. As developed below, if the allowed rate of return on common equity is only equal to the utility's 11.5% "bare bones" cost of equity, common stockholders will not earn their required rate of return on their $10 investment, since growth will really only be 6.25%, instead of 6.5%:

Year	Common Stock	Retained Earnings	Total Equity	Market Price	M/B Ratio	Allowed ROE	Earnings Per Share	Dividends Per Share	Payout Ratio
1	$ 9.52	$ -	$ 9.52	$10.00	1.050	11.50%	$ 1.09	$ 0.50	45.7%
2	$ 9.52	$ 0.59	$10.11	$10.62	1.050	11.50%	$ 1.16	$ 0.53	45.7%
3	$ 9.52	$ 0.63	$10.75	$11.29	1.050	11.50%	$ 1.24	$ 0.56	45.7%
Growth			**6.25%**	**6.25%**			**6.25%**	**6.25%**	

The reason that investors never really earn 11.5% on their investment in the above example is that the $0.48 in flotation costs initially incurred to raise the common stock is not treated like debt issuance costs (*i.e.*, amortized into interest expense and therefore increasing the embedded cost of debt), nor is it included as an asset in rate base.

Q. Can you illustrate how the flotation cost adjustment allows investors to be fully compensated for the impact of past issuance costs?

A. Yes. As discussed earlier, one method for calculating the flotation cost adjustment is to multiply the dividend yield by a flotation cost percentage. Thus, with a 5% dividend yield and a 5% flotation cost percentage, the flotation cost adjustment in the above example would be approximately 25 basis points. As shown below, by allowing a rate of return on common equity of 11.75% (an 11.5% cost of equity plus a 25 basis point flotation cost

[63] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," Public Utilities Reports (1994) at 175.

adjustment), investors earn their 11.5% required rate of return, since actual growth is now equal to 6.5%:

Year	Common Stock	Retained Earnings	Total Equity	Market Price	M/B Ratio	Allowed ROE	Earnings Per Share	Dividends Per Share	Payout Ratio
1	$ 9.52	$ -	$ 9.52	$10.00	1.050	11.75%	$ 1.12	$ 0.50	44.7%
2	$ 9.52	$ 0.62	$10.14	$10.65	1.050	11.75%	$ 1.19	$ 0.53	44.7%
3	$ 9.52	$ 0.66	$10.80	$11.34	1.050	11.75%	$ 1.27	$ 0.57	44.7%
Growth			**6.50%**	**6.50%**			**6.50%**	**6.50%**	

The only way for investors to be fully compensated for issuance costs is to include an ongoing adjustment to account for past flotation costs when setting the return on common equity. This is the case regardless of whether or not the utility is expected to issue additional shares of common stock in the future.

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

A. In order to account for the impact of past issuance costs, I recommend a flotation cost adjustment of 25 basis points, which corresponds with the midpoint of the range discussed earlier. After incorporating an adjustment for flotation costs of 25 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 currently in the 11.25% to 12.25% range, with a midpoint of 11.75%.

IV. RETURN ON EQUITY FOR BLACK HILLS

Q. What is the purpose of this section?

A. In addition to presenting the conclusions of my evaluation of a fair rate of return on equity for Black Hills, this section also discusses the relationship between ROE and preservation of a utility's financial integrity and the ability to attract capital, and evaluates the reasonableness of Black Hills' capital structure.

A. Implications for Financial Integrity

Q. Why is it important to allow Black Hills an adequate return on equity?

A. Given the social and economic importance of the electric utility industry, it is essential to maintain reliable and economical service to all consumers. While Black Hills remains committed to provide reliable electric service, a utility's ability to fulfill its mandate can be compromised if it lacks the necessary financial wherewithal.

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

A. Yes. While providing an ROE that is sufficient to maintain Black Hills' ability to attract capital, even in times of financial and market stress, is consistent with the economic requirements embodied in the Supreme Court's *Hope* and *Bluefield* decisions, it is also in customers' 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, customers also bear a significant burden when the ability of the utility to attract necessary capital is impaired and service quality is compromised. To continue to meet potential challenges successfully and economically, it is crucial that Black Hills receive adequate support for its credit standing.

Q. What dangers does an inadequate rate of return pose to Black Hills?

A. In light of Black Hills' present credit ratings, an inadequate rate of return imposed in this proceeding would further pressure the Company's financial flexibility and credit standing. In order to meet rising demand for electricity, Black Hills has sought to acquire additional power resources to ensure its ability to maintain adequate reserve margins and provide reliable service. As noted earlier, the Company's long-term plans include significant plant investment to ensure that the energy needs of its service territory are met, with Moody's noting the "[l]ikely need for additional generation capacity over the intermediate to longer term."[64] While providing the infrastructure necessary to meet the energy needs of customers is certainly desirable, it imposes additional financial responsibilities on Black Hills.

Q. Do the potential exposures faced by Black Hills highlight the need for ongoing support of the Company's financial strength and ability to attract capital?

A. Most definitely. A number of potential challenges might require the relatively swift commitment of capital resources in order to maintain the high level of service to which its customers have become accustomed. Given the potential for significant volatility in wholesale fuel and energy markets and Black Hills' lack of control over the timing of such events, the Company must have the wherewithal to meet these challenges even when capital and energy market conditions are unfavorable.

Experience demonstrates that, while investor confidence can evaporate almost overnight, it is difficult to recover and the damage is not quickly or easily reversed. Events in the Western U.S. provide a dramatic illustration of just how swiftly unforeseen circumstances can lead to deterioration in a utility's financial condition, and stakeholders have discovered first hand how difficult and complex it can be to remedy the situation after the fact. For a utility with an obligation to provide reliable service, investors' increased reticence to supply additional capital during times of crisis highlights the necessity of

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[64] Moody's Investors Service, "Black Hills Power, Inc.," *Credit Opinion* (Jun. 2, 2005) at 2.

preserving the flexibility necessary to overcome periods of adverse capital market conditions.

Q. What role does regulation play in ensuring a utility's access to capital?

A. Considering investors' heightened awareness of the risks associated with the electric power industry and the damage that results when a utility's financial flexibility is compromised, supportive regulation remains crucial in preserving access to capital. Investors recognize that constructive regulation is a key ingredient in supporting utility credit ratings and financial integrity, particularly during times of adverse conditions. S&P noted that:

> Regulatory rulings have returned to center stage as a dominant factor in assessing companies' credit quality. These decisions will be critical for an industry that in many jurisdictions is nearing the end of extended transition periods and will be making significant capital investment in infrastructure during the next several years.[65]

Investors recognize the importance of financial flexibility, especially considering the capital markets' ability to constrict access to capital when investors' confidence is compromised. As S&P observed:

> 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.[66]

Q. Are these concerns germane to Black Hills and its investors?

A. Yes. While acknowledging that South Dakota's regulatory environment has generally been supportive, the investment community recognizes that regulation has its own risks. With respect to Black Hills specifically, Moody's noted that its existing credit ratings "assume

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[65] Standard & Poor's Corporation, "Industry Report Card: U.S. Electric/Gas/Water," *RatingsDirect* (May 3, 2005) at 1.

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

that it will receive supportive regulatory treatment,"[67] and concluded that "signs of less supportive regulation in any of its jurisdictions could cause us to revisit the outlook or the existing ratings."[68]

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. Investors have many alternatives and competition for capital is intense. Lingering uncertainties from a prior era, as well as new challenges in the electric power industry, breed reluctance to make the long-term commitment of capital that is required to ensure the reliable and economic supply of electricity that customers both demand and deserve. Thus, while customers might realize short-term "savings" through a downward-biased ROE, these will prove illusory when the utility is precluded from making investments that are consistent with providing sustained, high quality service at the lowest possible price in the long run.

B. Impact of Proposed Fuel and Purchase Power Adjustment Clause

Q. Is it uncommon for regulators to allow energy cost adjustments for electric utilities?

A. No. Since the 1970's, when sharp spikes in energy prices led to significant unrecovered electric supply costs, adjustment mechanisms that enable utilities to implement rate changes to recover fluctuations in fuel costs have been widely prevalent. As electric utilities' reliance on purchased power grew, adjustment mechanisms were also generally expanded to include purchased power costs. A 2005 report by Fitch identified only 19 vertically

[67] Moody's Investors Service, "Black Hills Corporation," *Analysis* (June 2005) at 4.
[68] *Id.*

integrated utilities without some form of energy cost pass-through mechanisms in place.[69] Indeed, of the eleven utilities included in the proxy group used to estimate the cost of equity, nine are at least partially insulated from exposure to fluctuations in the cost of fuel and purchased power through an energy cost adjustment or have the ability to seek cost recovery outside the framework of a traditional rate case.[70] Accordingly, while cost of equity estimates for the proxy group presumably include a risk premium commensurate with normal operating and business risks, they clearly do not compensate investors for bearing the much greater uncertainties associated with exposure to price volatility in energy markets.

Q. Do investors recognize that exposure to changes in fuel and purchased power costs implies greater investment risk?

A. Yes. As fluctuations in the wholesale energy markets have become more pronounced in recent years, exposure to swings in fuel and power costs have become of increasing concern to investors. RRA noted that:

> Volatility in wholesale electricity markets has raised investors' level of awareness and concern with regard to the ability of electric utilities to recover wholesale power costs and fuel expenses from customers.[71]

Similarly, Fitch concluded that "[v]olatile and rising energy commodity costs represent a challenge to investor-owned electric utility companies."[72] Investors understand that, without an FPPA, Black Hills is forced to bear the risks of potential volatility in energy and

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[69] Fitch Ratings, Ltd., "Outlook 2005: U.S. Power & Gas," *Global Power/North America Special Report* (Jan. 6, 2005) at 27-29. In addition to FPPAs, certain utilities benefited from riders or temporary recovery mechanisms designed to address energy cost recovery. Black Hills was not included in the survey.

[70] Aside from Black Hills Corp., PNM Resources is currently operating under a retail rate freeze.

[71] Company 2005 Form 10-K Reports; Regulatory Research Associates, "Special Report: Fuel and Wholesale Power Cost Recovery," *Regulatory Focus* (Oct. 3, 2005).

wholesale power markets while being obligated to provide reliable service irrespective of the associated costs to its shareholders. Unlike competitive firms that may choose to increase prices or withdraw from the market altogether, a utility operating under traditional regulation without the benefit of an energy adjustment mechanism has little flexibility to accommodate fluctuations in power supply costs. Exposing Black Hills to these uncertainties while setting fixed retail prices that may fail to recover necessary costs would represent the worst of both the competitive and regulated paradigms.

Q. If the SDPUC were to reject an FPPA for Black Hills, would that have an impact on the cost of equity?

A. Most definitely. Considering the magnitude of the events that have transpired since the third quarter of 2000, investors' sensitivity to the uncertainties imposed by power market volatility has increased dramatically. S&P noted early on that without a mechanism to regularly adjust rates, escalating commodity prices can create significant financial damage for retail service providers. S&P regards the lack of an FPPA as one of the greatest impediments to financial stability:

> One of the most significant threats today to utilities' credit quality is uncertainty about the timely ability to pass power costs on to consumers. The issue for Standard & Poor's is this: To what lengths are regulators prepared to go to shelter ratepayers from the vagaries of the market and thereby threaten the financial strength of the utilities? … To preserve credit quality, these companies must be able to adjust rates not just to cover the cost of procuring power, but also to deliver the appropriate price signals to consumers.[73]

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[72] FitchRatings, "U.S. Electric Utilities: Credit Implications of Commodity Cost Recovery," *Global Power/North America Special Report* (Feb. 13, 2006).

[73] Standard & Poor's, "California Aside, Regulatory Support for Utility Credit Quality Remains Intact", *RatingsDirect*, p. 2 (Jul. 13, 2001).

Investors' required rates of return for utilities are premised on the regulatory compact that allows the utility an opportunity to recover reasonable and necessary costs. By sheltering utilities from exposure to extraordinary power cost volatility through an FPPA, customers benefit from lower capital costs than they would otherwise bear. Of course, the corollary implies that shifting the burden of extraordinary risks to shareholders would have the effect of considerably increasing the cost of equity to Black Hills, with the end-result being a greater cost of utility service to customers.

Q. Would approval of an FPPA remove all risks associated with the costs of fuel and purchased power?

A. No. As discussed earlier, while approval of a modified FPPA would be supportive of Black Hill's financial integrity, even for electric utilities with permanent fuel and purchased power adjustment mechanisms in place, significant risks remain. For example, investors recognize that an FPPA would not insulate Black Hills from the ongoing potential for regulatory disallowances. As S&P observed:

> FPPAs vary substantially in their ability to protect utilities daily and under catastrophic market movements. Moreover, it is critical to note that FPPAs are not a substitute for supportive regulation; the regulator's ability to disallow costs through ex-post prudency review, regardless of the existence of a FPPA, is a fact of life for utilities.[74]

Similarly, Fitch noted that "because of the … potential for substantial disallowances of such costs," significant uncertainties remain even for utilities with fuel and purchased power cost adjustment mechanisms.[75]

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[74] Standard & Poor's Corporation, "Fuel and Power Adjusters Underpin Post-Crisis Credit Quality of Western U.S. Utilities," *Utilities & Perspectives* (Oct. 18, 2004).

[75] FitchRatings, "Outlook 2005: U.S. Power & Gas," *Global Power/North America Special Report* (Jan. 6, 2005) at 26.

C. Impact of Firm Size

Q. Are capital market estimates for the proxy group of electric utilities directly applicable to Black Hills?

A. No. The market capitalization for the firms in the proxy group of electric utilities averaged approximately $5.6 billion. This compares with a market capitalization for Black Hills Corp. of approximately $1.1 billion. As noted earlier, for a variety of reasons, investors regard larger firms as less risky than smaller firms. Large, diversified companies can more easily weather unpleasant surprises while smaller companies lack equivalent resources.

Q. What is the magnitude of the adjustment required to account for this size premium?

A. One estimate of the size premium is available from Ibbotson Associates, which reports data for "Mid-Cap" and "Low-Cap" stocks in addition to its better-known reports on the S&P 500. Mid-Cap companies comprise the 3rd through 5th size-deciles of those stocks listed on the New York Stock Exchange, American Stock Exchange, and NASDAQ, while Low-Cap stocks represent the 6th through 8th size-deciles.

The individual firms in the Mid-Cap group have market capitalizations at or below about $7.2 billion but greater than $1.7 billion, with the market capitalization of Low-Cap stocks falling between approximately $1.7 billion and $586 million.[76] These smaller companies have historically earned higher rates of return than the large companies comprising the S&P 500. For the 1926 to 2005 period, Ibbotson Associates reported a size premium in excess of the return implied by the CAPM of 102 basis points for the mid-cap sector, or 181 basis points for low-cap companies.[77]

[76] Ibbotson Associates, *2006 Yearbook, Valuation Edition* at 130.
[77] *Id.* at Table 7-7, p. 139.

Q. Is there any other evidence that quantifies the difference in the cost of equity between large and small utilities?

A. Yes. A study reported in *Public Utilities Fortnightly* noted that the betas of small companies do not fully account for the higher realized rates of return associated with small company stocks:

> The smaller deciles show returns not fully explainable by the CAPM. The difference in risk premium (realized versus CAPM) grows larger as one moves from the largest companies in decile 1 to the smallest in decile 10. The difference is especially pronounced for deciles 9 and 10, which contain the smallest companies.[78]

The study went on to conclude that a publicly traded utility with a market capitalization of $1.0 billion would require a small company premium of approximately 130 basis points above the rate of return for larger firms.

Q. What does this evidence imply with respect to the cost of equity for a relatively small utility, such as Black Hills?

A. Considering Black Hills Corp.'s market capitalization of approximately $1.1 billion, this data implies that investors require a rate of return significantly in excess of the cost of equity estimates discussed above.

D. Capital Structure

Q. Is an evaluation of the capital structure maintained by a utility relevant in assessing its return on equity?

A. Yes. Other things equal, a higher debt ratio, or lower common equity ratio, translates into increased financial risk for all investors. A greater amount of debt means more investors

[78] Annin, Michael, "Equity and the Small-Stock Effect", Public Utilities Fortnightly (Oct. 15, 1995), at 43.

have a senior claim on available cash flow, thereby reducing the certainty that each will receive their contractual payments. This increases the risks to which lenders are exposed, and they require correspondingly higher rates of interest. From common shareholders' standpoint, a higher debt ratio means that there are proportionately more investors ahead of them, thereby increasing the uncertainty as to the amount of cash flow, if any, that will remain.

Q. What common equity ratio is implicit in Black Hills' requested capital structure?

A. Black Hills' capital structure is presented in the testimony of Garner Anderson. As summarized in his testimony, the common equity ratio used to compute Black Hills' overall rate of return was approximately 54% in this filing.

Q. What was the average capitalization maintained by the reference group of utilities?

A. As shown on Exhibit WEA-8, for the eleven firms in the proxy group, common equity ratios at December 31, 2005 ranged from 40.2% to 60.6% and averaged 49.2%.

Q. What implication does the increasing risk of the utility industry have for the capital structures maintained by utilities?

A. The decline in credit quality in the electric industry is indicative of the need for utilities to strengthen their balance sheets to deal with an increasingly uncertain and competitive market. S&P cited higher debt leverage and the inadequacy of financial profiles in the electric industry as one of the key factors explaining this deterioration.[79] A more conservative financial profile is consistent with increasing uncertainties and the need to maintain the continuous access to capital that is required to fund operations and necessary system investment, even during times of adverse capital market conditions.

As shown on Exhibit WEA-8, Value Line expects that the average common equity ratio for the proxy group of Western utility holding companies will increase to 53.0% over the next three to five years, with the individual common equity ratios ranging from 47.5% to 66.0%.

Q. How does Black Hills' common equity ratio compare with those maintained by the reference group of utilities?

A. Black Hills' requested common equity ratio of approximately 54% is entirely consistent with the range of capitalizations maintained by the proxy group at year-end 2005 and falls slightly above the 53.0% average equity ratio based on Value Line's expectations for these utilities over the near-term.

Q. What other factors do investors consider in their assessment of a company's capital structure?

A. Depending on their specific attributes, contractual agreements that obligate the utility to make specified payments may be treated as debt in evaluating Black Hills' financial risk. For example, as discussed earlier, a portion of Black Hills' power requirements are obtained through long-term purchased power contracts. Because power purchase agreements ("PPAs") typically obligate the utility to make specified minimum contractual payments akin to those associated with traditional debt financing, investors consider a portion of these commitments as debt in evaluating total financial risks. Because bond ratings agencies and investors consider the debt impact of such fixed obligations in assessing a utility's financial position, they imply greater risk and reduced financial flexibility.

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[79] See *e.g.*, Standard & Poor's Corporation, "Credit Quality For U.S. Utilities Continues Negative Trend", *RatingsDirect* (Jul. 24, 2003).

Q. How do PPAs impact a utility's financial position?

A. When a utility enters into a PPA, the fixed charges associated with the contract increase the utility's financial risk in the same way that long-term debt and other financial obligations increase financial leverage. Under current accounting rules, the accounting for a PPA is not discretionary if the transaction meets specified tests for accounting for capital leases, which require that the obligation be explicitly recorded as a debt obligation on the utility's balance sheet. As a result, the utility must rebalance its capital structure by increasing its common equity in order to restore its capitalization ratios to previous levels. Since the cost of equity exceeds the cost of debt, this rebalancing imposes additional costs, which are properly considered by regulators.

Q. Do PPAs that do not meet the accounting definition for capital lease treatment still impact investors' assessment of a utility's financial risks?

A. Yes. The accounting standards simply reflect the longstanding perception of investors that the fixed obligations associated with PPAs diminish a utility's creditworthiness and financial flexibility. The implications of purchased power commitments have been repeatedly cited by major bond rating agencies in connection with assessments of utility financial risks.

For example, in reviewing its evaluation of the credit implications of PPAs, S&P affirmed its position that such agreements are "debt-like in nature" and that the increased financial risk must be considered in evaluating a utility's credit risks.[80] As the rating agency explained:

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

> [P]urchased power agreements typically result in the assumption of fixed costs representing the portion of the purchase price that is linked to the capacity component of the total payment. These fixed capacity payments are similar to debt service payments incurred by a utility that constructs debt-financed power generation facilities. Therefore, whether a utility builds its own generating plants, or enters into a long-term power purchase agreement with a fixed-cost component, that utility is taking on a financial risk.[81]

When evaluating Black Hills' financial risks, investors likewise recognize that the Company's contractual payment obligations under PPAs are fixed commitments with debt-like characteristics. Unless Black Hills takes action to offset this additional financial risk by maintaining a higher equity ratio, the resulting leverage will weaken the Company's creditworthiness and place downward pressure on its ratings, implying a higher required rate of return for Black Hills' debt and equity securities.[82]

Q. What does this evidence suggest with respect to Black Hills' proposed capital structure?

A. Based on my evaluation, I concluded that Black Hills' requested capital structure represents a reasonable mix of capital sources from which to calculate the Company's overall rate of return. While industry averages provide one benchmark for comparison, each firm must select its capitalization based on the risks and prospects it faces, as well its specific needs to access the capital markets. A public utility with an obligation to serve must maintain ready access to capital so that it can meet the service requirements of its customers. The need for access becomes even more important when the company has large capital requirements

[81] Standard & Poor's Corporation, "Prepurchased Power and Its Implications for Public Power Ratings," *RatingsDirect* (Nov. 6, 2003).

[82] 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.

over a period of years, and financing must be continuously available, even during unfavorable capital market conditions.

Black Hills' proposed capital structure is consistent with industry benchmarks and reflects the Company's ongoing efforts to maintain its credit standing and support access to capital on reasonable terms. Indeed, Moody's specifically cited the Company's financial policies as support for Black Hill's current ratings, concluding that:

> The rating also reflects recent steps to moderate the debt level and reduce interest expense through redemption of a high cost first mortgage bond issue with cash on hand and internal borrowing from the parent, Black Hills Corp. (BHC).[83]

The reasonableness of Black Hills' requested capital structure is reinforced by the ongoing uncertainties associated with the electric power industry, the need to accommodate the additional risks associated the Company's relatively small size, and the importance of supporting continued system investment, even during times of adverse industry or market conditions.

E. Return on Equity Recommendation

Q. What then is your conclusion as to a fair rate of return on equity for Black Hills?

A. As explained earlier, based on the various capital market oriented analyses described in my testimony, and after incorporating an adjustment for flotation costs, I concluded that the fair rate of return on equity range for the electric utility proxy group was 11.25% to 12.25%. Considering capital market expectations, the potential exposures faced by Black Hills, and the economic requirements necessary to maintain financial integrity and support additional

[83] Moody's Investors Service, "Black Hills Power, Inc.," *Credit Opinion* (Jun. 2, 2005) at 2.

capital investment even under adverse circumstances, it is my opinion that the middle of this range, or 11.75%, represents a fair and reasonable ROE for Black Hills.

In evaluating the rate of return for Black Hills, it is important to consider investors' continued focus on the unsettled conditions in restructured energy markets, as well as other risks associated with the utility industry, such as heightened exposure to regulatory uncertainties. Combined with Black Hills' relatively small size, these factors imply a level of investment risk and required return that exceeds that of the proxy group used to estimate the cost of equity. Indeed, after considering evidence regarding the premium associated with a small-cap company, even the low-end result of my quantitative analyses for the proxy group would imply a rate of return roughly equivalent to my recommendation in this case.

Q. Does this conclude your pre-filed direct testimony?

A. Yes.