EXHIBIT 24

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

In the matter of the Application of Northern States Power Company, a Minnesota Corporation For Authority to Increase Rates for Electric Service In North Dakota	)))))	Case No. PU - 10-657 Case No. PU - 11-55

AFFIDAVIT OF
S. Keith Berry

I, the undersigned, being duly sworn, depose and say that the foregoing is the Direct Testimony of the undersigned, and that such Direct Testimony and the exhibits or schedules sponsored by me to the best of my knowledge, information and belief, are true, correct, accurate and complete, and I hereby adopt said testimony as if given by me in formal hearing, under oath.

S. Keith Berry

Subscribed and sworn to before me, this 15TH day of August, 2011

Notary Public

OFFICIAL SEAL
MARY L. EAGLES
NOTARY PUBLIC - ARKANSAS
PULASKI COUNTY
MY COMMISSION EXPIRES 07-13-2012

Before the North Dakota Public Service Commission

In the Matter of the Application of Northern States Power Company,
a Minnesota corporation
For Authority to Increase Rates for Electric Utility Service in North Dakota

Case Nos. PU-10-657 and PU-11-55
Exhibit__(SKB-1)

TESTIMONY OF DR. S. KEITH BERRY
ON BEHALF OF
THE ADVOCACY STAFF

August 18, 2011

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is S. Keith Berry and my business address is 1600 Washington Avenue, Hendrix College, Conway, AR 72032.

Q. WHERE ARE YOU EMPLOYED?

A. My academic affiliation is Professor of Economics and Business at Hendrix College in Conway, Arkansas. I am also a principal in the firm of Economic and Financial Consulting Group, Inc.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I received my B.A. in mathematics from Hendrix College, and my Ph.D. in economics from Vanderbilt University. I was an instructor in statistics at Vanderbilt in 1976-77 and was an instructor/assistant professor at Hendrix College from 1977-79. In July 1979, I joined the Staff of the Arkansas Public Service Commission as Manager of the Finance Section. The primary responsibility of that Section was the preparation and presentation of testimony concerning the cost of capital in utility rate cases. I assumed the duties of Manager of both the Finance and Rate Sections in July 1980. I was promoted to Director of Research and Policy Development in September 1986. Beginning in September 1989, I returned to teaching at Hendrix College.

I have submitted testimony in more than seventy different proceedings before public service commissions or other regulatory agencies, including testimony in the area of cost of capital. My publications include articles in the *American Economic Review*, *Journal of Regulatory Economics*, *Land Economics*, the *Energy Journal* (coauthor), the *Journal of Economics and Business*, *The Quarterly Review of Economics and Business*, *The Financial Review*, the *Eastern Economic Journal*, *Managerial and Decision Economics*, *Public Choice*, and the *Review of Industrial Organization*. I have made presentations concerning utility regulation and the cost of capital at the National Association of Regulatory Utility Commissioners ("NARUC") Advanced Studies Program, the Eastern NARUC Utility Rate Seminar, the Western NARUC Utility Rate Seminar, the National Conference of Regulatory Utility Commission Engineers, and the Annual Conference of the Institute of Public Utilities. While on the Staff of the Arkansas Public Service Commission, I served on the NARUC Subcommittee on Electricity and the Research Advisory Committee of the National Regulatory Research Institute (Deputy Chairman, 1988-89). I am currently a member of the American Economic Association and the Southern Economic Association. A copy of my *Curriculum Vita* is provided in Exhibit__ (SKB-2).

Q. ON WHOSE BEHALF ARE YOU APPEARING?

A. I am appearing on behalf of the Advocacy Staff of the North Dakota Public Service Commission.

II. SUMMARY OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. I will make recommendations concerning the cost of capital, including cost of equity, of Northern States Power-Minnesota ("NSPM") operating in North Dakota. I will also rebut the Direct Testimony of NSPM cost of capital witness Ann E. Bulkley.

Q. WHAT HAVE YOU REVIEWED IN THE PREPARATION OF YOUR DIRECT TESTIMONY?

A. I have reviewed the Company's filing in this Docket, including testimony, exhibits, and workpapers, responses to data requests, relevant issues of *Value Line Investment Survey*, NSP's recent SEC Form 10-Qs and 10-K, and other documents and data.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. I recommend a capital structure with 52.564 percent common equity, 46.293 per cent long-term debt, and 1.143 per cent short-term debt. This is the same capital structure proportions that the Company is proposing, which I find to be reasonable. The Company is requesting a cost of equity of 11.25% and a weighted cost of capital of 8.74%. My analysis indicates that reasonable estimate of the cost of equity is in the range of 9.3% - 10.3%. Based on my point recommendation of 9.55%, which reflects an adjustment for lower risk, my recommended weighted average cost of capital is 7.85%. This is shown in my Exhibit__(SKB-3).

III. CAPITAL STRUCTURE FOR NSPM

Q. HOW DID YOU CALCULATE THE OVERALL RATE OF RETURN, OR WEIGHTED AVERAGE COST OF CAPITAL?

A. I utilized the weighted average cost of capital approach wherein the various components' capital costs are weighted by their proportions in the capital structure and then summed.

Q. WHAT CAPITAL COMPONENTS DID YOU EMPLOY?

A. Common equity, long-term debt, and short-term debt, as shown in Exhibit ___(SKB-3).

Q. PLEASE EXPLAIN THE DETERMINATION OF THE RELATIVE PROPORTIONS OF THESE CAPITAL COMPONENTS.

A. I used the same capital structure as the Company proposed, which I found to be reasonable.

IV. COST OF DEBT FOR NSPM

Q. HOW DID YOU DETERMINE THE COST OF LONG-TERM DEBT FOR NSPM?

A. I used a 6.07% cost rate, which is the same as the Company's.

Q. HOW DID YOU DETERMINE THE COST OF SHORT-TERM DEBT FOR NSPM?

A. I used a 2.06% cost rate, which is the same as the Company's.

V. COST OF EQUITY FOR NSPM

Q. PLEASE DISCUSS THE FINANCIAL AND ECONOMIC TENETS THAT GUIDED YOU IN ESTIMATING NSPM'S COST OF EQUITY.

A. The cost of, or required return on, equity is a valid cost just as other more explicit expenses incurred by the utility in the provision of utility service to ratepayers. The difficulty with estimating the cost of equity is that it is nowhere explicitly stated in a utility's accounts, and must be inferred from market data.

If the return allowed by the regulatory authority is set higher than the required return on equity, then monopoly profits will inure to the benefit of the shareholders, at the expense of customers. If the return is set too low, then the financial position of the shareholders will be eroded and the utility will be unable to adequately attract necessary capital. When the allowed return on equity is set equal to the cost of equity, stockholders will be given the opportunity to earn a fair return on equity, which will also afford the utility the opportunity to viably attract capital. Thus, from the perspective of balancing the interests of ratepayers and shareholders, and simulating the competitive market model, a cost-based allowed return on equity is a desirable goal. Note that in the case of the cost of equity that is estimated with current data, the cost of equity is also the marginal cost of equity. The decisions that consumers make will be based on those price signals, which reflect the economic costs, including the marginal cost of equity, to society of providing

utility service. In that sense, an allowed return based on the cost of equity is economically efficient.

In my analysis of the cost of equity for NSPM, I relied solely upon the Discounted Cash Flow Method, since other methods for estimating the cost of equity are unreliable as I discuss in my Rebuttal of Ms. Bulkley.

Q. PLEASE DISCUSS YOUR RISK-COMPARABLE SAMPLE.

A. In order to develop a market-based cost of equity and have sufficient data in the analysis it is appropriate to use a sample of companies comparable in risk to NSPM. A s a starting point I utilized the same Risk Comparable sample as did Ms. Bulkley except that I: (1) Included Xcel Energy ("Xcel"), the parent company of NSPM, in the sample (2) Excluded DPL and Progress Energy from the Risk Comparable sample since both of those companies are parties to merger transactions; and (3) Excluded Hawaiian Electric because of its significant holdings of American Savings Bank.

For cost of capital purposes it is reasonable to include NSPM's parent company as a part of the risk-comparable sample. There is no circularity involved because Xcel's common equity is used to supply NSPM's common equity. That is the only source of common stock for NSPM. Surely an analysis of NSPM's cost of equity should include an analysis of the cost of equity of the sole supplier of NSPM's common equity. Further, note that NSPM accounted for approximately 42% of Xcel's revenues in calendar year 2010. This

indicates that NSPM accounts for a significant part of Xcel's operations, and implicitly, Xcel's cost of equity.

VI. DISCOUNTED CASH FLOW METHODOLOGY

Q. PLEASE DISCUSS YOUR APPLICATION OF THE DISCOUNTED CASH FLOW METHOD ("DCF") TO ESTIMATE NSPM'S COST OF EQUITY.

A, The concept of a return to capital is closely associated with time: a reward to the suppliers of capital for deferring consumption. Calculations of the embedded costs of debt are relatively straightforward since those costs are fixed and contractual in nature. The cost of equity, in contrast, is not spelled out in a contractual manner and is more difficult to calculate. However, it can be inferred through an appropriate examination of current stock market data and widely disseminated financial information.

Rational investors in common stock are primarily concerned with the cash flows that they expect to receive from ownership of the stock. For the individual investor those cash flows consist of expected future dividends as well as capital gains or losses expected from selling the stock at some future point in time. However, for investors in aggregate (across ownership changes) expected cash flows are comprised of future dividends only. There is no conceptual difference between these two interpretations of cash flow.

The market price of the common stock embodies investors' expectations about that stream of future dividends. However, a dividend expected to be received in the future is not valued as highly by investors as that same dividend received today. The investor implicitly imputes a discount to future dividends. Also, the further in the future the dividend is expected to be received, the greater is the discount.

This value, or market price, that investors impute to that share of common stock is the present value of the stream of dividends expected to be received by them. These future dividends are discounted by an amount determined by the discount rate, or cost of equity. This relationship is characterized in Equation (1) below where P_0 represents the current share price, D_i represents the dividend expected to be received at the end of period "i", and "k" is the discount rate, or cost of equity:

$$(1) \qquad P_0 = D_1/(1+k) + D_2/(1+k)^2 + D_3/(1+k)^3 + \ldots$$

In this form, without further simplifying and reasonable assumptions, Equation (1) is mathematically intractable. However, if we assume that investors expect future dividends to increase at a constant rate of growth, g, then Equation (1) can be expressed as:

$$(2) \quad P_0 = D_1/(1+k) + D_1(1+g)/(1+k)^2 + D_1(1+g)^2/(1+k)^3 + \ldots$$

Equation (2) can then be solved for P_0 as:

(3) $P_0 = D_1/(k-g)$, for $k > g$.

Equation (3) demonstrates that this constant growth DCF method is a market-based approach. Any changes in investors' discount rate, expected growth rate in dividends, or dividends expected one period hence are actually captured by changes in the market price of the stock. For example, other things being equal, if the cost of equity decreases, then investors will bid the market price up.

The constant growth DCF model shown in Equation (3) can be re-expressed as:

(4) $k = D_1/P_0 + g$,

which implies that the cost of equity is simply the sum of the expected dividend yield and the anticipated growth rate. Because of the quarterly nature of dividend payments, I have defined $D_1 = D_0(1 + g/4)$, where D_0 is the current annualized dividend. Thus, the final form of the DCF equation is:

(5) $K = D_0(1 + g/4)/P_0 + g$.

Q. HOW DID YOU DETERMINE THE GROWTH RATE IN YOUR DCF MODEL?

A. It is important for the analyst to ascertain investors' expectations about future sustainable long-term growth in dividends per share in order to properly implement the DCF method. Keep in mind that it is not what the analyst believes future growth will be, but what

investors believe about future long-term sustainable growth. It is those expectations that influence the stock price. Further, if sustainable, growth in book value per share ("BVPS"), earnings per share ("EPS"), and dividends per share ("DPS") will be equivalent.

I utilized recent editions of *Value Line Investment Survey*, a well-respected and widely disseminated source of information about companies, to develop my array of data for inferring investors' growth expectations. I also used the growth estimates of Ms. Bulkley, shown in Exhibit__(AEB-1), Schedule 3, page 3 of 3.

I used seven different estimates of investor-expected growth:

(1) g1 – Expected 10 year EPS annual growth for the years 2005 to 2015 as reported in *Value Line*;[1]

(2) g2 – Expected 10 year BVPS annual growth for the years 2005 to 2015 as reported in *Value Line*;[2]

(3) g3 – Expected annual EPS growth for the years 2007-09 to 2014-16 as reported in *Value Line*;

(4) g4 – Zack's projected EPS annual growth as shown in Bulkley Exhibit_(AEB-1), Schedule 3, page 1 of 3;

(5) g5 – First Call's projected EPS annual growth as shown in Bulkley Exhibit_(AEB-1), Schedule 3, page 1 of 3;[3]

[1] For some Companies the ten year period was 2004-2014 given the data presented by *Value Line*. Portland General's was calculated over a nine-year period because of data limitations.
[2] For some Companies the ten year period was 2004-2014 given the data presented by *Value Line*. Portland General's was calculated over a nine-year period because of data limitations.

(6) g6 – "br + vs" using data reported in *Value Line* for the years 2014-16;[4] and

(7) g7 –"br + vs" using data reported in *Value Line* for the years 2010-11.

It is my opinion that taken together these seven growth rates provide a reasonable basis upon which to infer the investor-expected growth rate in the DCF method.

Note that the expression "br + vs" is a measure of long-term sustainable expected growth in BVPS, based on two fundamental sources of BVPS growth: earnings retention ("br") and accretion (or dilution) of BVPS due to the issuance of new common stock ("vs"). Since the DCF formula relies on investor-expected growth in DPS, and since long-term growth is ultimately derived from, and equal to, long-term growth in BVPS, this approach is useful in gauging investors' dividend growth expectations.

The "br" component implicitly considers factors that cause sustainable growth in DPS, EPS, and BVPS due to earnings retention, where "b", the expected retention ratio, is multiplied times "r", the expected return on equity. A simple example, assuming no stock issuance, should clarify the working of this component. Assume that a company has an initial BVPS of $20, "r" is equal to 10%, and "b" is equal to 40%. Investors expect this hypothetical utility to earn 10% X $20 = $2.00 per share. Of this amount 40%, or $.80 per share is retained, and 60%, or $1.20 per share, will be paid out in dividends. The BVPS will grow to $20.80 in the next period because of earnings retention. This represents a growth in BVPS of ($20.80-$20)/$20 = 4%. EPS in the next

[3] For Xcel, g4 and g5 were not used since they were not presented in Ms. Bulkley's Testimony.
[4] For some Companies the period was 201302015 because of the data presented in *Value Line*.

period will be 10% X $20.80, which represents growth in EPS of 4%. DPS in the next period are 60% X $2.08 = $1.248, which also represents growth of 4%. DPS, EPS, and BVPS all grow at the long-term sustainable growth rate of 4%.

At this juncture, it is important to point out that "r", the *expected* return on equity is not necessarily equal to "k", the *required* return on equity. That investor-expected return on equity, "r" may be greater or less than "k", the investor-expected required return on equity. In particular, if "r" is greater (less) than "k", then the stock-market price-to-book value ratio is greater (less) than one. It is only when r = k that the price-to-book ratio is equal to one.

Another fundamental factor that determines sustainable growth in BVPS, EPS, and DPS is represented by the "vs" term. This second determinant of growth in BVPS is caused by the issuance of new common stock. If new stock is issued at a price below BVPS, dilution decreases the BVPS, and the investor-expected growth rate is thereby decreased. Conversely, if new stock is issued at a price above BVPS, accretion occurs and the growth rate is correspondingly increased. This factor is significant to investor expectations if the price-to-book value is significantly greater than one and if the firm is expected to issue common stock in the future (as reflected in *Value Line*). In this case those two conditions are met with regard to the Risk Comparable sample. This factor is discussed extensively in *Cost of Capital to a Public Utility* by Myron Gordon, who provided a major impetus for the use of the DCF method in utility rate proceedings.

For each firm, "vs" was calculated as n*(P/B – 1) where n* is the expected annual rate of growth in common shares outstanding, P is the arithmetic average of the monthly high and low stock prices for the period December 2010 – May, 2011 (obtained from corresponding editions of *Standard and Poor's Stock Guide*), and B is the BVPS at the end of calendar year 2010 (as reported in *Value Line*).

These different growth rate estimates are shown in Exhibit__(SKB-4).

Q. PLEASE DISCUSS YOUR CALCULATIONS OF THE OTHER COMPONENTS IN THE DCF METHOD.

A. In the DCF procedure, it is important to utilize a price term that is fairly current since a current price embodies all of the information currently available to investors, and will implicitly embody a current estimate of investors' required return on equity. However, that price should be averaged in an appropriate manner so as to eliminate the influence of random fluctuations in price. In order to minimize the possibility of an aberrant price I utilized an average price over a recent time period, December, 2010 - May, 2011. This method employed the high and low stock prices for each month. Those results are shown in Exhibit__(SKB-5).

The appropriate dividend yield for each firm was calculated using the annualized dividend as reported in *Standard's and Poor's Stock Guide, June, 2011*, and the arithmetic average of the high and low stock prices for the months of December, 2010 -

May, 2011 , as reported in *Standard's and Poor's Stock Guide.* Those results are shown in Exhibit__(SKB-5).

Q. WHAT ARE YOUR COST OF EQUITY DCF RESULTS USING THESE SEVEN DIFFERENT GROWTH RATE ESTIMATES AND THE ADJUSTED DIVIDEND YIELDS FOR EACH COMPANY IN THE RISK COMPARABLE SAMPLE?

A. Those results are shown in Exhibit__(SKB-6) for k1 through k7, which correspond to growth rates g1 through g7, respectively. As shown there the average DCF cost of equity is approximately 9.8%

Q. DID YOU MAKE A FLOTATION COST ADJUSTMENT?

A. No, I did not. In response to a data request, the Company stated that Ms. Bulkley's testimony was not intended to indicate that there are specific projected stock issuances by Xcel during that period. Further, the Company stated that it was changing the testimony of Ms. Bulkley on p. 21, lines 26-28 to state: "The Company may need to access the equity market in the next several years on a more regular basis than in the past in order to finance its capital investment plan." (Response to Data Request No. AS-COC-9 attached as Exhibit__(SKB-7)). Note that Xcel is the parent company of NSPM.

Because of the uncertainty associated with projected common stock issuances, and the corresponding uncertainty of incurrence of flotation expenses, in this case, it is inappropriate to include a flotation cost adjustment for purposes of NSPM's allowed return on equity.

Q. WHAT IS YOUR DCF-BASED RECOMMENDATION FOR THE ALLOWED RETURN ON EQUITY IN THIS CASE?

A. Based on the prior analysis discussed above my recommendation is a cost of equity range of 9.3% - 10.3%, with a point recommendation of 9.8%, unadjusted for lower risk.

Q. DID YOU PLACE ANY RELIANCE OR WEIGHT ON OTHER COST OF EQUITY METHODS SUCH AS THE CAPITAL ASSET PRICING MODEL OR THE RISK PREMIUM METHODS?

A. No, I did not. Those methods are generally unreliable for reasons that I will discuss later in my Direct Testimony.

Q. DID YOU MAKE ANY ADJUSTMENTS TO YOUR COST OF EQUITY ESTIMATES?

A. Yes, I did. It is my understanding that NSPM is proposing a Projected Test Year. If, indeed, a Projected Test Year is used for purposes of calculating NSPM-North Dakota's revenue requirement in this case, then much, if not all of the Company's risk of regulatory lag will be eliminated.

Q. WHAT IS REGULATORY LAG?

A. Regulatory lag is the lag between the time a utility incurs higher and prudent expenses and the time that it recovers those higher expenses from ratepayers. That lag tends to

increase a utility's risk and cost of equity. Of course, that increased risk is implicitly reflected in a market-based cost of equity method such as the DCF method. In particular, the price is lower and the estimated cost of equity is correspondingly higher. In this case, the use of a Projected Test Year diminishes that risk associated with regulatory lag.

Also, it is my understanding that North Dakota Law 49-05-16 provides that advance determination of prudence potentially gives investors protection from investment failure. That law provides a more favorable regulatory atmosphere in North Dakota, which reduces the risk of NSPM's operations in North Dakota.

Consequently, for consistency it is appropriate to adjust downward the cost of equity and allowed return on equity to reflect that lower risk. In this case I adjusted the point estimate of 9.8% downward by 25 basis points to 9.55% to reflect that diminishing of regulatory risk.

Q. WHAT IS YOUR OVERALL COST OF CAPITAL RECOMMENDATION FOR NSPM IN THIS CASE?

A. My overall recommendation is 7.85% as shown in Table 1 below.

TABLE 1

Capital Component	Proportion	Cost	Weighted Cost
Long-Term Debt	46.293%	6.07%	2.81%
Short-Term Debt	1.143%	2.06%	0.02%
Common Equity	52.564%	9.55%	5.02%

OVERALL WEIGHTED COST OF CAPITAL = 7.85%

VII. REBUTTAL OF NSPM WITNESS BULKLEY

Q. DR. BERRY, HAVE YOU READ AND ANALYZED THE COST OF CAPITAL TESTIMONY, EXHIBITS AND WORKPAPERS OF NSPM WITNESS MS. ANN E. BULKLEY?

A. Yes, I have.

Q. DO YOU DISAGREE WITH PARTS OF HER ANALYSIS AND CONCLUSIONS?

A. Yes, I do.

Q. WHICH PARTS OF HER ANALYSIS DO YOU DISAGREE WITH?

A. I disagree with her analysis and conclusions in the following areas:

(1) The Risk Comparable sample;

(2) The dividend yield Ms. Bulkley uses in her DCF analysis;

(3) The growth rate estimates she used in her DCF analysis;

(4) The growth adjustment made to the dividend yield in her DCF analysis;

(5) The weight given the risk premium method and her calculation of the risk premium estimate of the cost of equity;

(6) The flotation adjustment applied to her recommended allowed return on equity; and

(7) Her evaluation of the Company's risk compared with the risk-comparable sample using the ratio of capital expenditures to net plant.

Q. PLEASE DISCUSS YOUR MODIFICATIONS TO MS. BULKLEY'S RISK-COMPARABLE SAMPLE.

A. As I discussed earlier, I deleted DPL and Progress Energy from the Risk Comparable sample because they are each engaged in merger discussions, which can have a skewed impact on stock prices. I included Xcel in the in the Risk Comparable Sample since Xcel is the parent company of NSPM, and NSPM constitutes a significant portion of Xcel's earnings per share (approximately 37% in 2010). I excluded Hawaiian Electric because of its significant holdings of American Savings Bank.

Q. PLEASE DISCUSS YOUR DIFFERENCES WITH MS. BULKLEY'S DIVIDEND YIELD.

A. I utilized more recent prices than did Ms. Bulkley, which were higher. This resulted in lower dividend yields for DCF purposes than Ms. Bulkley's. This does not reflect an error on the part of Ms. Bulkley, but simply reflects the fact that since Ms. Bulkley filed testimony in December, 2010, her DCF prices were based on prices from 2010, which

were lower than the prices I used. Nevertheless, it is appropriate to use my price terms since they are more recent.

Q. PLEASE DISCUSS THE GROWTH RATE ESTIMATES USED BY MS. BULKLEY IN HER DCF ANALYSIS.

A. As discussed in her Direct Testimony (p. 17, line 8 through p. 18, line 13) she solely relied on EPS growth rate projections to estimate the investor-expected sustainable long-run growth rate in DPS. There are three general problems with relying exclusively on her approach.

First, in the DCF method it is important to estimate sustainable long-run growth rates in DPS. No doubt, earnings growth rates are a factor in dividend growth rates, but they are not the sole factor that investors would look to in formulating their dividend growth rate expectations. As I discussed earlier, investors also look to expected dividend growth rates, expected book value growth rates, and expected earnings retention. Ms. Bulkley places entirely too much weight on short-term earnings growth rate expectations.

Second, the earnings growth rates that she exclusively utilizes are simply not sustainable. As shown in Exhibit AEB-1, Schedule 3, page 3 of 3, the average growth rate in earning per share she uses is 6.37%. However, as I discussed earlier, a key long-term component of dividend growth is derived from growth in book value per share. Most of that growth is derived from earnings retention, or the "br" factor that I discussed earlier. As shown in my Exhibit__(SKB-8), the "b" factor for the risk-comparable group is approximately

40%. Given that g" is approximately equal to "br", this implies that, in the context of Ms. Bulkley's analysis, 6.37% = 40% X r, or that r, the investor-expected return on equity, is r = 6.37%/40% = 15.925%, or approximately 16%. There is absolutely no evidence that investors expect the utilities in the Risk Comparable sample to earn approximately 16% on a long-term sustainable basis. For example, as shown in my Exhibit__(SKB-8), both historical and expected returns on equity are in the range of 9-10%, significantly less than 16%. Consequently, Ms. Bulkley's 6.37% growth rate factor, relying exclusively on short-term EPD growth rate, is simply not sustainable, and is inappropriate for usage in the DCF method.

Third, while Ms. Bulkley characterizes her earnings growth estimates as long-term, they are not. The *Value Line* earnings growth rate estimates are for approximately seven years, and the Zach's and First Call estimates are for approximately five years. Utility EPS are more volatile than DPS and BVPS. Consequently, EPS *growth* rates are a lot more volatile than DPS and BVPS growth rates. As I have pointed out earlier, the growth rates appropriate for usage in the DCF method are long-term in nature. In the determination of the price in the DCF method, only about 20% to 30% of the market price is determined by the dividends in the first 5 to 7 years. Ms. Bulkley neglects the remaining 70% to 80% of future dividends that determine the market price and fails to consider investor's long-term growth rate expectations. To base long-term investor growth rate expectations exclusively on short term growth rates, as Ms. Bulkley did, is inappropriate.

Q. PLEASE DISCUSS YOUR DISAGREEMENT WITH MS. BULKLEY'S GROWTH RATE ADJUSTMENT TO THE DIVIDEND YIELD.

A. Ms. Bulkley adjusted the dividend yield by a factor of "1 + g/2". To better reflect the fact that dividends are paid quarterly, I prefer that an adjustment factor of "1 + g/4" be applied. In my opinion, Ms. Bulkley's adjustment leads to a small over-estimate of the DCF cost of equity.

Q. PLEASE DISCUSS MS. BULKLEY'S RISK PREMIUM ANALYSIS.

A. I have two problems with her risk premium analysis. First, the level of the risk premium is not only dependent upon the level of interest rates, but other factors as well. As I show in my article in *Managerial and Decision Economics*, attached as Exhibit—(SKB-9), interest rate variability correlates negatively with risk premia, and there is a general trending down in risk premia over time. Consequently, it is my opinion that the risk premium method is at best difficult to properly apply, and is just not reliable because of the instability of risk premia. Ms. Bulkley's risk premium conclusions should be accorded no weight by this Commission.

Second, even if the Commission were to accord some weight to the risk premium method, Ms. Bulkley has utilized speculative interest rate inputs into her risk premium analysis. Part of her analysis uses 2012-2021 projections of 30-year Treasury bond yields of 5.80 per cent. That interest rate assumption is entirely speculative, and does not reflect current market conditions. For example, the average of the 30-year Treasury bond yields for the period January, 2011 through June, 2011 is 4.45%. If we apply that Treasury

Bond yield to my risk premium equation in the article mentioned, the resultant risk-premium based cost of equity is approximately 10.25%. If we apply that Treasury Bond yield to her revised risk premium equation, the risk-premium based cost of equity is approximately 10.6%. Both of these are toward the top end on my cost of equity range. Note that I make these calculations for the benefit of the Commission, if it accords some weight to the risk premium method.

Q. PLEASE DISCUSS MS. BULKLEY'S ANALYSIS OF THE RATIO OF PROJECTED CAPITAL EXPENDITURES TO NET PLANT?

A. On pp. 28-32 of her Direct Testimony she makes the claim that NSPM's ratio of projected capital expenditures to net plant is significantly greater than the corresponding ratios for the Risk Comparable sample, and that because of that an allowed return on equity toward the upper end of the range of results is appropriate.

However, she is focusing on just one risk factor that investors are aware of in evaluating their risk expectations of NSPM. In fact, there is a myriad of risk factors that investors will consider. For example, investors consider:

(1) Macroeconomic conditions, both national and regional such as inflation rates, unemployment rates, Gross Domestic Product growth rates, and interest rates;

(2) Financial or regulatory accounting principles or policies imposed by the Financial Accounting Standards Board, the SEC, the Federal Energy Regulatory Commission, and similar entities with regulatory oversight;

(3) Changes in tax laws;

(4) Unusual, severe, or catastrophic weather conditions, which may simply be weather-induced decreases in usage, or storm-induced repairs to utility infrastructure;

(5) Unscheduled generation or transmission outages, maintenance, or repair;

(6) Unanticipated changes to fossil fuel, nuclear fuel, or natural gas supply costs, or unavailability due to higher demand, shortages, transportation problems or other developments;

(7) Nuclear or environmental incidents;

(8) Costs associated with the storage of spent nuclear fuel;

(9) Adequate funding of nuclear decommissioning trust funds;

(10) Electric transmission or natural gas pipeline constraints;

(11) Employee workforce factors, such as collective bargaining agreements with unions;

(12) Changes in environmental laws and regulations, including regulations related to carbon charges;

(13) Customer business conditions, including the percentage of load accounted for by business cycle sensitive industrial load;

(14) Conservation by customers;

(15) Nuclear regulatory policies and procedures;

(16) Credit risk associated with customers that do not pay their bills and counterparties that owe money or product and breach their obligations;

(17) Risks associated with funding of defined benefit pensions and post-retirement plans for employees;

(18) Increasing costs associated with health care plans; and

(19) Regulatory risk and regulatory lag.

Q. DOES THIS ARRAY OF RISK FACTORS IMPLY THAT ADJUSTMENTS SHOULD BE MADE TO YOUR DCF BASED COST OF EQUITY?

A. No, it does not. The common stock market price terms in the Risk Comparable sample implicitly reflect investor-evaluations of these risk factors. To the extent investors are concerned with these risk factors, the stock market price terms will be correspondingly lower and reflected in a greater dividend yield.

Consequently, Ms. Bulkley's implicit argument that investors focus disproportionately on the ratio of capital expenditures to net plant is fallacious, and should be accorded no weight by this Commission.

However, I should point out that regulatory lag looms large for investors and has an indirect bearing on most of the factors listed above. For example, if health care costs increase, regulatory lag associated with recovering those increases in health care costs will, other things being equal, increase a Company's risk and cost of equity. Consequently, any diminishing of regulatory lag will, other things being equal, decrease a Company's risk and cost of equity.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

S. KEITH BERRY

Department of Economics and Business, Hendrix College, 1600 Washington Avenue, Conway, AR 72032, Office Tel # (501) 450-1233, Fax # (501) 450-1233,Home Tel # (501) 217-4048, E-mail: berry@hendrix.edu

CURRENT POSITIONS

Professor, Department of Economics and Business
Hendrix College, 2002-Present

Vice President
Economic & Financial Consulting Group, Inc., 1990-Present
Conway, AR 72032

EDUCATION

Ph.D., Economics
Vanderbilt University, 1979

B.A., Mathematics
Hendrix College, 1973

PREVIOUS POSITIONS

Director, Center for Entrepreneurial Studies
Hendrix College, 2001-2007

Chair, Department of Economics and Business –Supervisor of five faculty
Hendrix College, 2003-05

Associate Professor of Economics and Business
Hendrix College, 1994-2002

Assistant Professor of Economics and Business
Hendrix College, 1989-1994

Director of Research and Policy Development-Supervisor of six policy analysts
Arkansas Public Service Commission, Little Rock, AR, 1986-1989

Manager of Rates and Finance Sections-Supervisor of six rate and financial analysts
Arkansas Public Service Commission, Little Rock, AR, 1979-1986

Instructor/Assistant Professor of Economics and Business
Hendrix College, Conway, AR, 1977-1979

Instructor
Vanderbilt University, 1976-77

COURSES TAUGHT

Principles of Micro
Principles of Macro
Industrial Organization
Environmental Economics
Money, Banking and Credit
Intermediate Micro
Intermediate Macro
International Economics
Principles of Statistics
Intermediate Statistics
Western Intellectual Traditions

CURRENT AND PAST CONSULTING ACTIVITIES WITH THE ARKANSAS PUBLIC SERVICE COMMISSION

I have been retained as a consultant and expert witness by the Arkansas Public Service Commission continuously since 1990. In that capacity, I have advised the Arkansas Commission, and filed testimony on behalf of the Arkansas Commission, on the following subjects:

(1) Regional Transmission Organizations;
(2) Independent Coordinator of Transmission;
(3) Locational marginal pricing;
(4) Resource Planning;
(5) Mergers;
(6) National Interest Electric Transmission Corridors;
(7) Transmission Planning
(8) Standard Market Design;
(9) Demand Side Resources;
(10) System Pooling Agreements;
(11) Stranded Costs;
(11) FERC Rulemaking on Transmission Issues;

(13) Fuel Adjustment Clauses;
(14) Interruptible Rates;
(15) Avoided Cost Pricing;
(16) Nuclear decommissioning rates;
(17) Retail electric utility rate cases;
(18) Gas Distribution utility rate cases.

TESTIMONY OR REPORTS PRESENTED TO COMMISSIONS OR AGENCIES

Federal Energy Regulatory Commission, Docket No. ER10-2001. Testimony concerning depreciation expense used in bandwidth calculations. April, 2011.

Federal Energy Regulatory Commission, Docket No. ER10-1350. Testimony concerning bandwidth calculations. December, 2010-January, 2011.

Federal Energy Regulatory Commission, Docket No. EL10-55-000. Testimony concerning depreciation expense used in bandwidth calculations. October, 2010.

Federal Energy Regulatory Commission, Docket No. EL09-1224-000. Testimony concerning 2009 bandwidth calculations for Entergy Operating Companies. January and February, 2010.

Connecticut Department of Public Utility Control. Participation in task force that performed a Management Audit of the Connecticut Light & Power Company, May, 2009.

Federal Energy Regulatory Commission, Docket No. ER09-636-000. Affidavit concerning Entergy Arkansas notice of intent to withdraw from the Entergy System Agreement, April, 2009.

Federal Energy Regulatory Commission, Docket No. EL08-51-000. Testimony concerning recovery of Spindletop regulatory asset in 2008 bandwidth remedy. February, 2009.

Federal Energy Regulatory Commission, Docket No. ER08-1056-000. Testimony concerning inclusion of certain Evangeline gas costs in 2008 bandwidth calculations for Entergy, January, 2009.

Federal Energy Regulatory Commission, Docket No. ER08-1056-000. Affidavit on 2008 bandwidth remedy on Entergy System. July 2008.

Federal Energy Regulatory Commission, Docket No. ER07-956-000. Testimony concerning Entergy System Agreement 2007 bandwidth effects of imprudence and depreciation, February-March, 2008.

Federal Energy Regulatory Commission, Docket No. EC07-70-000. Affidavit concerning Entergy acquisition of Calcasieu Power, LLC.

Maryland Public Service Commission, Case No. 9062. Testimony concerning the cost of capital of Chesapeake Utilities Corporation, August, 2006.

Federal Energy Regulatory Commission, Docket No. EL06-76-000. Affidavit in Complaint by APSC concerning production costs on the Entergy System, April, 2006.

Federal Energy Regulatory Commission, Docket No. ER03-583-000, et al. Testimony concerning purchased power agreements on Entergy System, November, 2003.

Federal Energy Regulatory Commission, Docket No. ER03-753-000. Testimony concerning unit power rate schedule on Entergy System, November, 2003.

Federal Energy Regulatory Commission, Docket No. EL01-88-000.
Testimony opposing production cost equalization on the Entergy System, March, 2003, April, 2003, and July, 2003.

Securities and Exchange Commission, File No. 70-9785, Affidavit concerning issues associated with exempt wholesale generators for American Electric Power, September, 2002.

Federal Energy Regulatory Commission, Docket No. EL01-88-000.
Affidavit opposing production cost equalization on the Entergy System, July, 2001.

Federal Energy Regulatory Commission, Docket Nos. EL00-66-000 et al.
Affidavit concerning production cost equalization on the Entergy System, May, 2001.

State of Arkansas General Assembly, Testimony concerning HB 1411 regarding funding of the White River Navigation Project, January, 2001.

Federal Energy Regulatory Commission, Docket Nos. EL00-66-000 et al.
Testimony concerning modification of Entergy System Agreement to accommodate deregulation and interruptible rates, December, 2000, January, 2001, and February, 2001.

Federal Energy Regulatory Commission, Docket Nos. EL98-40-000 et al.
Testimony concerning the merger of American Electric Power and Central and South West, May, 1999 and June, 1999.

Federal Energy Regulatory Commission, Docket No. EC99-18-000
Affidavit concerning the proposed acquisition of Pilgrim Nuclear Unit by Entergy Corporation, January, 1999.

Securities and Exchange Commission, File No. 70-9049
Affidavit concerning financial risk of diversification of Entergy Corporation, October, 1998.

Arkansas Public Service Commission, Docket No. 98-081-TF
Testimony concerning off-peak rates, March, 1998.

"Report on the Cost of Equity of New York Power Authority," December, 1997.

State of Arkansas General Assembly
Economic Policy Analysis of Telecommunications Reform Act of 1997, January, 1997.

Securities and Exchange Commission, File No. 70-8725
Affidavit concerning financial risk of diversification of Southern Company, October, 1996 and January, 1997.

Federal Energy Regulatory Commission, Docket No. ER95-53-000
Testimony concerning the equalization of nuclear decommissioning costs of Entergy, October, 1996.

Securities and Exchange Commission, File No. 70-8809
Affidavit concerning financial risk of diversification of Central and Southwest. May, 1996.

"Report on the Cost of Equity of New York Power Authority," January, 1996.

Federal Energy Regulatory Commission, Docket No. ER95-1042-000
Testimony concerning the cost of capital and nuclear decommissioning of System Energy Resources, October, 1995.

Federal Energy Regulatory Commission, Docket No. ER95-53-000
Affidavit concerning nuclear decommissioning cost equalization on the Entergy System. June, 1995.

"Report on the Development of Electric Utility and Railroad Comparable Samples for the Tax Division of the Arkansas Public Service Commission," February, 1995.

Federal Energy Regulatory Commission, Docket No. EL94-13-000
Testimony concerning the merger of Entergy and Gulf States Utilities. October, 1994.

Arkansas Public Service Commission, Docket No. 94-355-U
Testimony concerning the cost of capital of Louisiana-Nevada Transit. October, 1994.

Oklahoma Corporation Commission, PUD 940000354
Testimony concerning the cost of capital of Arkansas Louisiana Gas Co. July, 1994.

Arkansas Public Service Commission, Docket No. 94-175-U
Testimony concerning the cost of capital of Arkansas Louisiana Gas Co. June, 1994.

Securities and Exchange Commission, File No. 70-8339
Affidavit concerning the merger of Central and Southwest and El Paso Electric. April, 1994.

Federal Energy Regulatory Commission, Docket Nos. EC94-7-000 and ER94-898-000
Testimony concerning the merger of Central and Southwest and El Paso Electric. February, 1994.

Arkansas Public Service Commission, Docket No. 93-081-U
Testimony concerning the cost of debt of Arkansas Louisiana Gas Co. October, 1993.

Federal Energy Regulatory Commission, Docket Nos. EC92-21-000 and ER92-806-00
Testimony concerning the merger of Entergy and Gulf States Utilities. March, 1993.

Federal Energy Regulatory Commission, Docket Nos. ER92-341-000, EL92-35-000, and EL92-36-000
Testimony concerning the cost of capital of System Energy Resources. December, 1992.

Securities and Exchange Commission, File No. 70-8059
Affidavit concerning the merger of Entergy and Gulf States Utilities. November, 1992.

Oklahoma Corporation Commission, PUD 0001317
Testimony concerning the cost of capital and a weather normalization adjustment clause for Arkansas Louisiana Gas Co. May, 1992.

Kansas Corporation Commission, Docket No. 181,200-U
Testimony concerning the cost of capital and a weather normalization adjustment clause for Arkansas Louisiana Gas Co. May, 1992.

Arkansas Public Service Commission, Docket No. 92-032-U
Testimony concerning a weather normalization adjustment clause for Arkansas Louisiana Gas Co. February, 1992.

Arkansas Public Service Commission, Docket No. 89-143-C
Testimony concerning franchise fee or tax on AT&T in the City of Little Rock. January, 1992.

Federal Energy Regulatory Commission, Docket No. EL90-48-000
Testimony concerning the spin-off of a coal unit on the Entergy System. January, 1992.

Arkansas State Banking Commission
Economic and Financial Report on the Feasibility of the Proposed First Community Bank,

Conway, Arkansas (prepared by Economic & Financial Consulting Group, Inc.), May, 1991

Arkansas Public Service Commission, Docket No. 90-133-U
Testimony concerning non-traffic sensitive costs on telephone systems. November, 1990.

Federal Energy Regulatory Commission, Docket Nos. ER89-678-000 and EL90-16-000
Testimony concerning the cost of capital and nuclear decommissioning of System Energy Resources. November, 1990

Arkansas Public Service Commission, Docket No. 90-004-U
Testimony concerning the capital structure of Arkansas Western Gas Co. October, 1990.

Arkansas Public Service Commission, Docket No. 88-115-TF
Testimony concerning phase-in plan for Arkansas Power and Light Co. September, 1988.

Arkansas Public Service Commission, Docket No. 87-201-U
Testimony concerning the cost of capital of GTE Southwest, Inc. August, 1988.

Arkansas Public Service Commission, Docket No. 87-166-TF
Testimony concerning nuclear decommissioning trust fund of Arkansas Power and Light Co. January, 1988.

Arkansas Public Service Commission, Docket No. 87-070-U
Testimony concerning the cost of capital of Arkansas Louisiana Gas Co. September, 1987.

Arkansas Public Service Commission, Docket No. 87-071-U
Testimony concerning the cost of capital of Arkansas Energy Resources. August, 1987.

Federal Energy Regulatory Commission, Docket Nos. EL86-58-000 and EL86-59-000
Testimony concerning the cost of capital of System Energy Resources, Inc. and Middle South Services. March, 1987

Arkansas Public Service Commission, Docket No. 87-028-U
Testimony concerning a preferred stock issuance by Arkla. March, 1987.

Arkansas Public Service Commission, Docket No. 84-165-U
Testimony concerning the cost of capital of Southwestern Bell. February, 1987.

Arkansas Public Service Commission, Docket No. 86-243-TF
Testimony concerning incentive rates for Arkansas Power and Light Co. January, 1987.

Securities and Exchange Commission, File No. 70-7299
Affidavit concerning a preferred stock issuance by System Energy Resources. December,

1986.

Arkansas Public Service Commission, Docket No. 86-175-TF
Testimony concerning incentive rates for Arkansas Power and Light Co. September, 1986.

Arkansas Public Service Commission, Docket No. 86-147-TF
Testimony concerning a tax adjustment rider for Arkansas Power and Light Co. August, 1986.

Arkansas Public Service Commission, Docket No. 86-112-TF
Testimony concerning seasonally differentiated rates of Arkansas Power and Light Co. June, 1986.

Arkansas Public Service Commission, Docket No. 86-090-U
Testimony concerning gas transportation policy. June, 1986.

Arkansas Public Service Commission, Docket No. 85-299-U
Testimony concerning cost allocations between customer classes on Arkansas Power and Light Co. February, 1986.

Arkansas Public Service Commission, Docket No. 84-249-U
Testimony concerning the cost of capital, incentive rates, and phase-in plan for Arkansas Power and Light Co. May, 1985.

Arkansas Public Service Commission, Docket No. 85-104-TF
Testimony concerning interruptible incentive rates for Arkansas Power and Light Co. May, 1985.

Arkansas Public Service Commission, Docket No. 85-043-U
Testimony concerning a rate freeze for Arkansas Louisiana Gas Co. February, 1985.

Arkansas Public Service Commission, Docket No. 84-084-U
Testimony concerning cost allocations and phase-in plan for Arkansas Electric Cooperative Corporation. September, 1984.

Arkansas Public Service Commission, Docket No. 84-199-U
Testimony concerning the cost of capital, rate design, and class cost allocations for Arkansas Power and Light Co. September, 1984.

Arkansas Public Service Commission, Docket No. F-007
Testimony concerning fuel and gas adjustment clauses. May, 1984.

Arkansas Public Service Commission, Docket No. 83-161-U
Testimony concerning the cost of capital and replacement cost pricing for Arkansas

Louisiana Gas Co. March 1984.

Arkansas Public Service Commission, Docket No. 83-253-U
Testimony concerning the cost of capital of AT&T. January, 1984.

Arkansas Public Service Commission, Docket No. 83-153-U
Testimony concerning the cost of capital of Allied Telephone Co. December, 1983.

Arkansas Public Service Commission, Docket No. 83-206-U
Testimony concerning a rate reduction for Arkansas Power and Light. December, 1983

Arkansas Public Service Commission, Docket No. 83-045-U
Testimony concerning the cost of capital and customer stock purchase plan on Southwestern Bell. September, 1983.

Arkansas Public Service Commission, Docket No. 81-104-AP-2
Testimony concerning nuclear fuel negative salvage costs of Arkansas Power and Light Co. July, 1983.

Arkansas Public Service Commission, Docket No. 82-314-U
Testimony concerning the cost of capital and customer stock purchase plan on Arkansas Power and Light Co. April, 1983.

Federal Energy Regulatory Commission, RM-80-36-000
Comments concerning a generic rate of return. December, 1982.

Illinois Commerce Commission, Docket No. 82-0152
Testimony concerning the cost of capital of Illinois Power Co. July, 1982.

Arkansas Public Service Commission, Docket No. 81-260-U
Testimony concerning the rate of return of Arkansas Electric Cooperative Corporation. June, 1982.

Arkansas Public Service Commission, Docket No. 82-037-U
Testimony concerning the cost of capital for Southwestern Bell. May, 1982.

Arkansas Public Service Commission, Docket No. 81-349-U
Testimony concerning the cost of capital of Associated Natural Gas Co. April, 1982.

Arkansas Public Service Commission, Docket No. TD-80-06
Testimony concerning overall capitalization rate. November, 1981.

Arkansas Public Service Commission, Docket No. 81-161-U
Testimony concerning the cost of capital of Oklahoma Gas and Electric. October, 1981.

Arkansas Public Service Commission, Docket No. 81-144-U
Testimony concerning the cost of capital and nuclear decommissioning trust funds for Arkansas Power and Light Co. September, 1981.

Arkansas Public Service Commission, Docket No. U-3136
Testimony concerning the cost of capital of Southwestern Electric Power Co. April, 1981.

Arkansas Public Service Commission, Docket No. U-3117
Testimony concerning an econometric model for directory assistance for Southwestern Bell Co. April, 1981.

Arkansas Public Service Commission, Docket No. U-3071
Testimony concerning the rate of return and an econometric model of demand for Arkansas Electric Cooperative Corp. July, 1980.

Arkansas Public Service Commission, Docket No. U-3089
Testimony concerning the rate of return of North Arkansas Telephone Cooperative. July, 1980.

Arkansas Public Service Commission, Docket No. U-3096
Testimony concerning the cost of capital of United Telephone Co. March, 1980.

Arkansas Public Service Commission, Docket No. U-3052
Testimony concerning the cost of capital of Associated Natural Gas Co. March, 1980.

Arkansas Public Service Commission, Docket No. U-3036
Testimony concerning the cost of capital of United Telephone Co. November, 1979.

HONORS AND AWARDS

Wincott Visiting Research Fellowship
University of Buckingham, United Kingdom, Fall, 1997

Earhart Fellowship (with Nicholas Georgescu-Roegen)
Vanderbilt University, 1975-1976

Graduate School Assistantship
Vanderbilt University, 1973-1976

Mosley Economics Award
Hendrix College, 1973

Hogan Math Award
Hendrix College, 1972

Alpha Chi (scholastic),
Hendrix College

Rensselaer Math and Science Award, 1968

PUBLICATIONS

"Sub-Optimal Generation Portfolio Variance with Rate of Return Regulation," *Technology and Investment, 1*, 2010, pp. 114-17.

"Firm Incentives for Invention Prizes With Multiple Winners," *Eastern Economic Journal, 32*, 2006, pp. 83-95.

"Generation Search Costs and Ramsey Pricing in a Partially Deregulated Electric Utility Industry," *Journal of Economics and Business, 54*, 2002, pp. 331-343.

"Substitution Between Bundled and Unbundled Products After Deregulation in Electricity Generation," *Eastern Economic Journal, 26*, 2000, pp. 455-68.

"Stranded Costs, Access Charges, and Ramsey Pricing in the U.S. Electric Utility Industry," *The Quarterly Review of Economics and Finance, 40*, 2000, pp. 503-17.

"Excess Returns in Electric Utility Mergers During Transition to Competition," *Journal of Regulatory Economics, 18*, 2000, pp.175-88.

"Interest Rate Risk and Utility Risk Premia During 1982-93," *Managerial and Decision Economics, 19*, 1998, pp. 127-35.

"Asymmetric Demand Information in Regulation," *Studies in Economics and Finance, 18*, 1998, pp. 129-41.

"Utility Mergers and the Cost of Capital," *Journal of Financial and Strategic Decisions, 11*, 1998, pp.73-82.

"Interest Rate Risk and Utility Bond and Dividend Yields," *Advances in Investment Analysis and Portfolio Management*, Volume III, 1995, pp. 183-191.

"Rent-Seeking With Multiple Winners," *Public Choice, 8*, 1993, pp. 437-43.

"A Risk-Adjusted Approach for Assessing Factors that Determine Utilities' Allowed Returns on Equity," (with Timothy Mason), *The Review of Industrial Organization*, *8*, 1993, pp. 113-23.

"Ramsey Pricing in the Presence of Risk," *Managerial and Decision Economics*, March-April, 1992, pp. 111-17.

"The Impact of Consumers on the Dissipation of Rents," *Eastern Economic Journal*, July-September, 1991, pp. 345-49.

"Expected Rate Minimization and Excess Capacity in Regulated Utilities," *The Quarterly Review of Economics and Business*, Volume 30, Number 3, Fall 1990, pp. 85-95.

"Flotation Cost Allowance Methodologies: A Synthesis Using Present Value Analysis," *The Financial Review*, Volume 25, Number 3, August, 1990, pp.487-500.

"The Allocation of Risk Between Stockholders and Ratepayers in Regulated Utilities," *Land Economics*, Volume 64, Number 2, May, 1988, pp. 114-24.

"Rate-of-Return Regulation and Demand Uncertainty with a Symmetric Regulatory Constraint," *The American Economist*, Fall, 1987, pp. 8-12.

"The Relevance of Quasi Rationality in Competitive Markets: Comment," *American Economic Review*, Volume 77, Number 3, June, 1987, pp. 496-8.

"The Ratepayer and Stockholder under Alternative Regulatory Policies: Comment," *Land Economics*, Volume 63, Number 2, May, 1987, pp. 201-5.

"The Impact of Nuclear Power Plant Construction Activity on the Electric Utility Industry's Cost of Capital," (with Samuel Loudenslager), *The Energy Journal*, Volume 8, Number 2, April, 1987, pp. 63-75.

"When is Excess Capacity Desirable?" *New Regulatory and Management Strategies in a Changing Market Environment*, Institute of Public Utilities, 1987, pp. 358-371.

"Random Pseudo-Disturbance Generators in a Stochastic Simulation of an Econometric Model,"(with Cliff Huang), *Journal of Statistical Computation and Simulation*, Vol.22, Nos. 3 and 4, pp. 285-302.

"The Quarterly Cost of Equity: Implications for Setting the Annual Return on Equity," *Electric Ratemaking*, Volume 2, Number 2, April/May, 1983, pp.8-10.

Book Review of *Issues in Public-Utility Pricing and Regulation*, edited by Michael A. Crew, Lexington. Mass.: D.C. Heath & Co., 1980, in *Southern Economic Journal*, Volume 48, Number 4, April, 1982, pp. 1112-3.

"The Discounted Cash Flow Formula: Validation and Estimation," *Proceedings of the Second NARUC Biennial Regulatory Information Conference*, pp.397-400.

WORKING PAPERS

"A Comparison of Pay-as-Bid and Market-Clearing-Price Bidding Processes in Electric Utility Auctions"

"Pay-as-Bid and Market-Clearing-Price Bidding Processes in Electric Utility Auctions with Merchants' Risk Preference"

"Sub-Optimal Generation Portfolio Variance with Rate of Return Regulation"

"Collusion in Rent-Seeking With Decreasing Returns to Scale"

PRESENTATIONS

"Offer Curve Behavior for Merchant Plants in Electric Utility Regional Transmission Organizations", 2005 Southern Economics Association Meetings, Washington, D.C.

"Deans, Teams, and Faculty Dreams: Cooperation in Hard Work," Speaker, Session at 57th Annual Meeting of the American Conference of Academic Deans, New Orleans, January, 2001.

"Changes in Risk in Electric Utility Mergers During Transition to Competition", 1999 Southern Economic Association Convention.

"Stranded Cost in the U.S. Electric Utility Industry: Last Gasp of Ramsey Pricing?" Discussion Paper, Wincott Series, University of Buckingham, United Kingdom, December, 1997.

"Interest Rate Risk and Utility Risk Premia During 1982-93," 1994 Southern Economic Association Convention.

"Interest Rate Risk and Utility Bond and Dividend Yields," 1992 Western Economic Association Convention.

"Scaling Up Nuclear Decommissioning Costs," NARUC Advanced Regulatory Studies Program, Williamsburg, VA, 1992.

"Assessing Factors That Determine Utilities' Allowed Returns on Equity: A Risk-Adjusted

Institutional Approach," (with Timothy Mason), 1989 Southern Economic Association Convention.

"The Grand Gulf Experience," Sixty-Fifth National Conference of Regulatory Utility Commission Engineers, Hot Springs, AR, 1987.

"Some Fundamental Principles in the Determination of a Utility's Cost of Capital," Seventh Annual Western Utility Rate Seminar, Salt Lake City, Utah, 1987.

"A Critique of Various Phase-in Plans," NARUC Advanced Regulatory Studies Program, Williamsburg, VA, 1986.

"Principles in the Determination of a Utility's Cost of Capital," Thirteenth Annual Eastern NARUC Utility Rate Seminar, Ft. Lauderdale, Florida, 1985.

"Nuclear Unit Construction and Electric Utilities' Cost of Capital," Western Economic Association Convention, 1984.

"Current Issues in Utility Regulation," Fifth Annual Seminar Series, Hendrix College, 1984.

"The Economics of Two-Part Rate Structures for Regulated Utilities," Midwest Economics Association Convention, 1981.

COLLEGIATE SERVICE

Chair, Department of Economics and Business. While Chair I led the Department in the development of an International Business Minor. This will be a precursor to an International Business Major.

Director, Center for Entrepreneurial Studies, Hendrix College, 2001-Present. I obtained $200,000 in external funding for the Center's start-up. The Center brought Secretary of Commerce Don Evans, former Secretary of HUD Jack Kemp, and former Council of Economic Advisors Chair Dr. Glenn Hubbard to speak to the Hendrix campus. Additionally, the Center sponsored a number of Business Roundtables where local businesspeople spoke to Hendrix students. In 2004, the Center provided supervision for a Hendrix Team that was a semi-finalist in the Arkansas Governor's Business Plan Competition.

Faculty Advisor, Phi Beta Lambda, the Collegiate Division of Future Business Leaders of America, 2002-Present

Chair, Committee on Curriculum, Hendrix College, 1998-2002. Responsible for development of new General Education Requirements as Hendrix moved from a trimester calendar to a semester calendar

Member of Search Committee for Provost for Hendrix College, 2002

Member of Faculty Committee that assisted in the writing of a $3.9 million grant to Hendrix College from the Robert & Ruby Priddy Charitable Trust, 2002

Hendrix College Alumni Association Board of Governors Awards Committee, 1999-2000

Chair, Committee on Student Life, Hendrix College, 1995-96

OTHER EXPERIENCE

Presentation on China Odyssey III at Conway Rotary Club, November, 2007

"Symposium on Business and the Liberal Arts: Integrating Professional and Liberal Education," Sponsored by the Council of Independent Colleges, Chicago, IL, May, 2007.

Member, eSTEM Public Charter Schools, Inc. Board of Directors, Little Rock, AR, 2007-Present

Discussant at 2005 American Economics Association/TPUG Session.

Chair, Finance Committee, Trinity United Methodist Church, 2005-06, Little Rock, AR.

Reviewer for *Quarterly Review of Economics and Finance, Eastern Economic Journal, Journal of Economic Surveys, Contemporary Economic Policy, Economics and Politics, Land Economics, The American Economist, Managerial and Decision Economics, International Journal of Energy Systems, Journal of Economics and Business,* and *IEEE PES Transactions on Power Systems*

Blue Ribbon Panel, advice to Frueauff Foundation concerning modification of its investment objectives, 2003

Discussant at 2001 Southern Economics Association Convention

"Report on the Economic Feasibility of the White River Navigation Project," February, 2000

Member, Board of the Arkansas Policy Foundation, 1999-Present

"The Democratization of Capitalism on Wall Street," *Log Cabin Democrat*, Conway, Arkansas, June 7, 1999

Panelist on Governor's Economic Summit, Roundtable on Tax and Regulatory Policy, June 9-10, 1998, Little Rock, AR

"Taxes and Savings in Arkansas," Murphy Commission Report, May, 1998

"Feasibility Analysis of the Formation of a Local Electric Utility in Batesville and Independence County," with Mike Hughes and W.W. Elrod,II, April, 1998

Discussant at 1999 Southern Economics Association Convention

Discussant at 1996 Western Economics Association Convention

Discussant at 1994 Southern Economics Association Convention

Discussant at 1993 Southern Economics Association Convention

Participant on judges' panel for selection of outstanding Arkansas businesses and executives in 1988 for *Arkansas Business*

Lecturer, Business Leaders Day, 1988, University of Arkansas, Fayetteville, Arkansas

Research Advisory Committee, National Regulatory Research Institute, 1986-1989, Deputy Chairman (1988-1989)

Subcommittee on Electricity, National Association of Regulatory Utility Commissioners, 1987-1989

Subcommittee on Economics, National Association of Regulatory Utility Commissioners, 1979-1987

PROFESSIONAL ORGANIZATIONS

American Economics Association
Southern Economics Association

CAPITAL PROPORTIONS AND OVERALL COST OF CAPITAL

Capital Component	Amount ($000's)	Proportion	Cost	Weighted Cost
Long-Term Debt	$3,399,494	46.293%	6.07%	2.81%
Short-Term Debt	$83,926	1.143%	2.06%	0.02%
Common Equity	$3,859,990	52.564%	9.55%	5.02%
Total	$7,343,410	100.000%		**7.85%**

DCF GROWTH RATES

Company	g1	g2	g3	g4	g5	g6	g7
AEP	3.57%	4.55%	3.50%	4.00%	3.90%	4.79%	3.96%
CLECO	6.83%	7.61%	8.00%	7.00%	3.00%	4.04%	6.04%
Great Plains Energy	-2.17%	3.68%	6.00%	13.00%	13.00%	2.17%	2.56%
IDACORP	5.02%	4.33%	5.50%	4.00%	4.00%	5.01%	5.83%
NextEra Energy	8.51%	8.47%	5.00%	6.40%	6.83%	6.40%	7.96%
Pinnacle West	3.10%	1.76%	6.00%	6.80%	5.50%	3.85%	3.73%
Portland General	7.77%	2.42%	3.00%	9.60%	5.75%	3.85%	3.67%
Southern Co.	4.32%	5.76%	5.00%	5.10%	5.32%	6.23%	5.18%
Westar Energy	4.47%	3.94%	8.50%	8.00%	10.00%	4.49%	2.93%
Xcel Energy	4.65%	4.41%	5.50%	NA	NA	4.52%	4.08%

STOCK PRICES AND DIVIDEND YIELDS

Company	Dec. 2010 Hi Price	Dec. 2010 Lo Price	Jan. 2011 Hi Price	Jan. 2011 Lo Price	Feb. 2011 Hi Price	Feb. 2011 Lo Price	Mar. 2011 Hi Price	Mar, 2011 Lo Price	Apr. 2011 Hi Price	Apr. 2011 Lo Price	May. 2011 Hi Price	May. 2011 Lo Price	Average Price	Quart. Dividend	Dividend Yield
AEP	$36.47	$34.92	$36.92	$35.19	$36.07	$34.96	$36.37	$33.47	$36.56	$34.37	$38.99	$36.07	$35.86	$0.46	5.13%
CLECO	$31.22	$30.05	$31.83	$30.56	$32.65	$31.05	$34.51	$31.93	$35.64	$33.91	$35.66	$33.73	$32.73	$0.28	3.42%
Great Plains Energy	$19.73	$18.79	$20.14	$19.10	$21.14	$18.97	$20.19	$18.90	$20.74	$19.58	$21.21	$20.04	$19.88	$0.21	4.18%
IDACORP	$37.76	$36.57	$38.72	$36.53	$38.37	$37.12	$38.30	$36.14	$39.39	$37.65	$40.38	$37.97	$37.91	$0.30	3.17%
NextEra Energy	$52.49	$50.25	$54.73	$51.54	$55.55	$53.70	$55.86	$52.04	$57.00	$54.28	$58.98	$56.34	$54.40	$0.55	4.04%
Pinnacle West	$41.99	$40.15	$42.26	$40.71	$42.42	$40.70	$44.07	$41.23	$43.47	$41.93	$45.64	$43.54	$42.34	$0.53	4.96%
Portland General	$22.65	$21.34	$22.63	$21.64	$23.45	$22.42	$24.00	$23.00	$25.00	$23.30	$26.00	$24.73	$23.35	$0.27	4.54%
Southern Co.	$38.49	$37.43	$38.79	$37.55	$38.19	$37.05	$38.62	$36.51	$39.05	$37.43	$40.87	$38.85	$38.24	$0.47	4.94%
Westar Energy	$25.52	$24.50	$26.07	$25.04	$26.35	$25.32	$26.60	$25.12	$27.23	$25.58	$27.98	$26.66	$26.00	$0.32	4.92%
Xcel Energy	$23.89	$23.19	$24.14	$23.26	$24.00	$23.40	$24.67	$23.17	$24.37	$23.28	$25.39	$24.10	$23.91	$0.26	4.35%

DCF COST OF EQUITY ESTIMATES

Company	k1	k2	k3	k4	k5	k6	k7
AEP	8.75%	9.73%	8.68%	9.18%	9.08%	9.98%	9.14%
CLECO	10.31%	11.10%	11.49%	10.48%	6.45%	7.49%	9.51%
Great Plains Energy	1.98%	7.90%	10.24%	17.31%	17.31%	6.36%	6.76%
IDACORP	8.22%	7.53%	8.71%	7.20%	7.20%	8.22%	9.04%
NextEra Energy	12.64%	12.60%	9.09%	10.51%	10.94%	10.51%	12.08%
Pinnacle West	8.09%	6.74%	11.03%	11.84%	10.53%	8.86%	8.73%
Portland General	12.40%	6.99%	7.57%	14.25%	10.36%	8.44%	8.25%
Southern Co.	9.31%	10.78%	10.00%	10.11%	10.33%	11.25%	10.19%
Westar Energy	9.45%	8.91%	13.53%	13.02%	15.05%	9.47%	7.89%
Xcel Energy	9.05%	8.81%	9.91%	NA	NA	8.92%	8.47%
Average	9.02%	9.11%	10.03%	11.54%	10.80%	8.95%	9.01%
Overall Average	**9.78%**						

☐ **Non Public Document – Contains Trade Secret Data**
☐ **Public Document – Trade Secret Data Excised**
☒ **Public Document**

Xcel Energy		
Docket No.:	PU-10-657 & PU-11-55	
Response To:	Blue Ridge Consulting	Data Request No.
Requestor:	Michael McGarry	AS-COC-9
Date Received:	April 28, 2011	

Question:
Provide projected information for XEI's projected common stock issuances for the years 2011-2015, as referred to on lines 26-28, p. 21 of Exhibit AEB-1. This information should include number of shares issued, total dollar value of issuance, and issuance costs.

Response:

Ms. Bulkley's testimony does not reference specific projected stock issuances for 2011-2015 and was not intended to indicate that there are specific projected stock issuances during that period. As a point of clarification, the referenced sentence on lines 26-28, p. 21 of Ms. Bulkley's testimony should state:

"The Company ~~will~~ may need to access the equity market in the next several years on a more regular basis than in the past in order to finance its capital investment plan."

Preparer:	Ann E. Bulkley
Title:	Vice President, Concentric Energy Advisors, Inc.
Telephone:	508-263-6200
Date:	May 16, 2011

EARNED RETURNS ON EQUITY AND RETENTION RATIOS

Company	r 2010	r 2011	r 14-16	b 2010	b 2011	b 14-16
AEP	9.32%	10.70%	10.42%	34.23%	40.65%	44.00%
CLECO	11.39%	10.40%	9.65%	57.21%	53.62%	41.82%
Great Plains Energy	7.31%	6.05%	7.45%	45.75%	36.15%	31.43%
IDACORP	9.54%	9.24%	8.49%	57.89%	58.62%	54.84%
NextEra Energy	14.43%	12.10%	10.82%	57.81%	51.16%	52.38%
Pinnacle West	9.28%	9.10%	9.15%	32.26%	33.33%	34.29%
Portland General	8.17%	8.21%	8.42%	38.82%	38.86%	40.00%
Southern Co.	12.72%	12.76%	12.87%	24.05%	24.80%	32.31%
Westar Energy	8.60%	8.23%	10.00%	31.11%	26.86%	40.00%
Xcel Energy	9.55%	10.22%	10.00%	35.90%	41.14%	42.50%
Average	10.03%	9.70%	9.73%	41.50%	40.52%	41.36%

MANAGERIAL AND DECISION ECONOMICS
Manage. Decis. Econ. 19: 127–135 (1998)

Interest Rate Risk and Utility Risk Premia During 1982–93

S. Keith Berry*

Department of Economics and Business, Hendrix College, Conway, USA

INTRODUCTION

The risk premium method of calculating a fair return on equity for a regulated utility is frequently used in regulatory proceedings. That method considers the relationship between a utility's bond yield and its required return on equity, and is especially useful when other methods, such as the capital asset pricing model and the discounted cash flow (DCF) model exhibit less reliability.[1] Although the discounted cash flow method is the favored method for estimating a utility's cost of equity in rate proceedings, the risk premium method provides a useful check on the DCF results. This is even more important in today's financial environment because of the difficulty of measuring investor-expected growth rates in the DCF method.

If bond yields and required returns on equity move up and down in lockstep, it is straightforward to calculate the appropriate cost of equity using the risk premium method. However, if they do not, estimation of the cost of equity is much more difficult. One explanation of this variability in risk premia is differences in 'interest rate risk'. In particular, arguments have been made in rate cases that utility bonds are riskier in the 1980s than they were earlier because of the significant increase in interest rate variability that occurred in the early 1980s (primarily caused by increased inflation rate variability).[2] In particular, when capital costs, and interest rates, increase, utility bondholders, who earlier 'locked-in' at lower interest rates, miss out on those higher interest rates. Bondholders who experience this will then prospectively require an 'interest rate risk' premium, and utility bond interest rates will be correspondingly greater. Furthermore, utility bonds of differing overall risk may exhibit differing sensitivities to that 'interest rate risk'.

In contrast, the argument goes, utility common stock returns have some protection from that risk. If capital costs increase, utilities can request a rate increase to increase the allowed return. Consequently, utility common shareholders can earn the higher capital costs, and do not necessarily require an 'interest rate risk' premium.[3] Thus, over time we would not necessarily expect to see utility bond yields and required equity returns move in one-to-one lockstep. Furthermore, to the extent that there is some substitutability between utility common stocks and utility bonds as interest rate risk associated with bonds increases, investors may increase their preferences for utility stocks. This should tend to decrease required returns on utility common stock.

Berry (1995) performed an analysis of the impact of interest rate (and capital cost) risk on interest rates and dividend yields. Those results indicate that interest rates are positively related to interest rate variability, but dividend yields are not affected by dividend yield variability. However, that study focused on *dividend yields*, which are easy to measure, and did not consider required equity returns which are much more difficult to measure. Furthermore, that study did not focus on risk premia, and the relationship between bond yields and required returns on equity, as does this paper. This paper utilizes required returns, as measured by Commission-allowed returns, in the risk premium analysis.

* Correspondence to: Department of Economics and Business, Box 3180, Hendrix College, Conway, AR 72032, USA.

CCC 0143–6570/98/020127-09$17.50

Other studies have shown that there is an inverse relationship between interest rates and risk premia in recent years, but not in earlier years. Carleton *et al.* (1983) found that there was no relationship between electric utility risk premia and interest rates during the 1970s. Brigham *et al.* (1985) estimated a positive relationship between risk premia and interest rates for the 1966–79 period and a negative relationship between the variables during the 1980–84 period. They attributed this to increased inflation risk and its effect on interest rates. Similarly, Harris (1986) showed that there was a negative relationship between utility risk premia and interest rates during the 1982–84 period. Harris and Marston (1992) concluded that there was a negative relationship between the S&P 500 risk premia and interest rates for the 1982–91 period. However, none of these studies used Commission-allowed returns in the calculations of risk premia.

This paper considers two factors not previously considered in the literature. First, allowed returns are used as a proxy for required returns on equity, with appropriate consideration for partial adjustment. Second, explicit usage is made of measures of interest rate risk to gauge their impact on risk premia. Regression analyses is employed to estimate the effects of utility bond yields, interest rate variability, and time trends on required returns on equity and risk premia over the period 1982–93. In the second section, we present a simple regression model, which tests for an inverse relationship between required returns on equity and interest rates. This model, while not very sophisticated, has the inherent advantage that it can be easily used to estimate risk premia. In the third section, we consider a more complex model which explicitly considers various measures of interest rate variability, as well as interest rate levels.

REGRESSION RESULTS WITH INTEREST RATES

A common formulation of the risk premium is:

$$K = YD + RP \quad (1)$$

where K is the required return on common equity, YD is the utility's current cost of long-term debt (yield) and RP is the risk premium. Since YD is directly measurable, and *if* RP can be properly measured, K can then be directly estimated.[4] However, there are two general problems with the implementation of a risk premium methodology:

1. The estimation of RP is often based on historical earned returns, which may or may not be indicative of *required* returns; and
2. The level of RP may not be constant through time. In particular, there may be an inverse relationship between interest rates and risk premia.[5]

To address the first problem we use Commission-allowed returns as a reasonable surrogate for required returns, with a partial adjustment feature, as will be discussed later. Commissions and their staff spend a significant amount of time in rate cases considering the determination of a utility's appropriate return on equity. As discussed earlier, the primary method employed is the DCF method, which, when performed properly, estimates the required return on equity.[6] Furthermore, Commission-allowed returns may represent better estimates of equity costs, than DCF methods using analysts' forecasts, since Commissions comprehend a wide variety of cost of capital methods.

For illustration we have arrayed risk premia by year in Table 1. For comparative purposes we also show the estimated risk premia using the long-term US Treasury bond yield. Note that there is a general upward trend in risk premia associated with Moody's utility bond yields, which occurs during a period of generally decreasing interest rates. Furthermore, the estimated risk premia are less than those reported in Harris and Marston (1992). This can be attributed to two factors. First, utilities are generally less risky than the S&P 500 which were used in the Harris and Marston study, with corresponding lower required returns. Second, Commission-allowed returns may incorporate lower DCF growth rates than the analysts' forecasts used by Harris and Marston.

Finally, risk premia for Treasury bonds, shown in Table 1, appear to be fairly stable, albeit with a slight upward drift over the 1982–93 period. Moody's yields fell by much more (777 basis points) over that period, than did Treasury yields (578 points). An explanation for this is provided in Berry (1995). As shown there, although there is a close one-to-one relationship between Moody's utility bond yields and Treasury yields, interest rate risk had a significant impact on Moody's

Table 1. Equity Risk Premia

Year (1)	US Treasury Bond Yields (2) (%)	Allowed Return on Equity (3) (%)	Equity Risk Premia on Treasury Yields [(3)–(2)] (4) (%)	Moody's Utility Bond Yields (5) (%)	Equity Risk Premia on Moody's Yields [(3)–(5)] (6) (%)
1982	12.23	15.46	3.23	15.33	0.13
1983	10.84	15.18	4.34	13.31	1.87
1984	11.99	15.25	3.26	14.03	1.22
1985	10.75	14.38	3.63	12.29	2.09
1986	8.14	13.2	5.06	9.46	3.74
1987	8.64	12.86	4.22	9.98	2.88
1988	8.98	12.82	3.84	10.45	2.37
1989	8.58	12.92	4.34	9.66	3.26
1990	8.74	12.63	3.89	9.76	2.87
1991	8.16	12.41	4.25	9.21	3.20
1992	7.52	11.84	4.32	8.57	3.27
1993	6.45	11.54	5.09	7.56	3.98
Change 1982–93	−5.78	−3.92	+1.86	−7.77	+3.85

Note: 1993 data are partial year.

yields. The decrease in interest rate risk during the 1980s, consequently, caused an incremental decrease in Moody's yields, in excess of that corresponding to the decrease in Treasury yields.[7] As will be discussed later, although the risk premia associated with Treasury bonds appear to be fairly stable during the 1982–93 period, there are specific reasons for that, which will not necessarily be repeated in the future.

In our regression analysis we use allowed returns and the corresponding bond yields for that utility's Moody's bond rating from 6 months earlier than the date of the Commission rate order.[8] This provides a better matching since the evidentiary record on the required return on equity is usually developed some months before the date of the rate order. The data on allowed returns was obtained from various editions of *Public Utilities Fortnightly* (1983–93).[9] The data on Moody's bond yields was obtained from various editions of *Moody's Public Utility Manual* (1982–93). This yielded a total of 1226 rate case observations over the period 1982–93. For each month we averaged the cross-sectional data to obtain 130 usable time series observations.[10]

Consistent with Equation (1), let K_t^* represent the required return on equity at time t such that

$$K_t^* = RP_t + YD_t \tag{2}$$

where RP_t and YD_t are the risk premium and current cost of debt at time t, respectively. To allow for a varying risk premium set

$$RP_t = \alpha + \beta YD_t. \tag{2a}$$

Postulate a regulator adjustment function of the form:

$$K_t - K_{t-1} = \gamma(K_t^* - K_{t-1}), \quad 0 < \gamma < 1 \tag{3}$$

where K_t is the allowed return at time t and γ is the adjustment factor. This equation implies an inertia on the part of regulators such that with a change in the required return on equity from the prior period's allowed return on equity, $K_t^* - K_{t-1}$, the regulator only moves part way to a new allowed return. The greater the value of γ, the greater the degree of regulator adjustment.[11]

Substitution of Equation (2) into Equation (3) yields

$$K_t = \gamma RP_t + \gamma YD_t + (1-\gamma)K_{t-1} \tag{4}$$

or

$$K_t = \alpha\gamma + (1+\beta)\gamma YD_t + (1-\gamma)K_{t-1} \tag{4a}$$

For purposes here, we used the allowed return from 1 month earlier. Regulators are aware of recent allowed returns and will likely partially base their current allowed return awards on those recent historical allowed returns, consistent with Equation (3).[12] We then performed an ordinary least squares regression of the allowed returns on the corresponding bond yields and lagged allowed returns. This resulted in the following regression equation:

$$K_t = 0.03337 + \underset{(6.11)}{0.22301}\,YD + \underset{(8.58)}{0.56788}K_{t-1},$$
$$(\text{Durbin-Watson} = 2.41,\ R^2 = 0.905). \quad (5)$$

The t-statistics are shown in parentheses, and indicate significance for both independent variables at the 1% level. The implied value of γ, the adjustment factor, is $1 - 0.56788 = 0.43212$.

The implied risk premium equation, corresponding to Equation (2a), is

$$RP_t = 0.07722 - 0.48392\,YD_t. \quad (6)$$

Equation (6) indicates the presence of an inverse relationship between risk premia and interest rates. For every 100 basis point drop in interest rates, the risk premium *increases* by approximately 48 basis points and the cost of equity decreases by approximately 52 basis points. Conversely, for every 100 basis point increase in interest rates, the risk premium *decreases* by approximately 48 basis points and the cost of equity increases by approximately 52 basis points.

To the extent interest rate variability is a major factor in the level of capital costs, we would expect to empirically observe this inverse relationship between risk premia and interest rates.[13] That is, as interest rate variability increases, interest rate risk increases, interest rates increase, and risk premia fall since utility equity costs change very little, or decrease, for the reasons mentioned in the introduction. The converse would be true in the case of a decrease in interest rate variability.[14]

An alternative formulation of Equation (1) is

$$K_t^* = RP_t + GOV_t. \quad (7)$$

where GOV_t is the yield on long-term US Treasury bonds and RP_t is the corresponding risk premium. Performing a similar regression analysis with GOV instead of YD produces:

$$K_t = 0.1981 + \underset{(3.74)}{0.16016}GOV_t + \underset{(12.09)}{0.73703}K_{t-1},$$
$$(\text{Durbin-Watson} = 2.56,\ R^2 = 0.889). \quad (8)$$

The R^2 is statistically significant at the 1% level with both independent variables statistically significant.

The implied risk premium equation, corresponding to Equation (2a), is

$$K_t^* = 0.07533 - 0.39096GOV_t. \quad (9)$$

This formulation, too, indicates an inverse relationship between risk premia, measured relative to Treasury bonds, and Treasury bond yields. In particular, note that for a given 100 basis point increase in interest rates the risk premium decreases by 39 basis points. The relative change in risk premia is not as great, which is attributable to less interest rate variability and interest rate risk associated with Treasury bonds.[15] Over the 1982–93 period, while Treasury yields fell by 578 basis points, Moody's utility bond yields fell by 777 basis points.

REGRESSION RESULTS WITH BOND YIELD VARIABILITY

A factor that could directly and significantly affect risk premia is investor-perceived variability in utility bond yields. It is likely that historical variability in those bond yields would impact investor perceptions of interest rate risk and increase utility bond yields. Furthermore, to the extent that there is some substitutability between utility common stocks and utility bonds, as interest rate risk associated with bonds increases, investors may increase their preferences for utility stocks. This should tend to decrease required returns on utility common stock.[16] Both of these effects will tend to reduce the risk premium when utility bond interest rate risk increases.

While some of that interest rate variability may be picked up in the data on interest rate levels, those interest rate levels also reflect other factors, such as general tightness (or laxity) in capital market conditions, prevalence of call provisions, and differential tax wedges.[17] Thus, we performed a regression analysis that explicitly included a measure for interest rate variability. An obvious measure is the standard deviation (S.D.) in interest rates in the immediate past. If our hypothesis is correct, an increase in the S.D. should decrease RP.

We considered two different historical timeframes for estimating the S.D.: 3 years and 5 years ($SD3$ and $SD5$, respectively). For example, with the 3 year time frame, the S.D. at month n is calculated using the 36 months prior to month n. With the 5-year time frame, the prior 60 months were used. Each of these measures was calculated separately for bond yields for Moody's *Aaa*, *Aa*, *A* and *Baa* utility bonds and then averaged across bond ratings to obtain the average $SD3$ and $SD5$ for each month.

Table 2. Regression Results With *YD*, Dependent Variable = *K*

Variable				
Constant	0.1077	0.0981	0.0790	0.1001
t	−0.0002** (−7.25)	−0.0002** (−6.16)	−0.0001** (−4.47)	−0.0002** (−6.09)
YD	0.2584** (7.55)	0.2032** (6.12)	0.1947** (5.57)	0.1950** (5.89)
SD3	−0.5087** (−5.31)			
RMSD3		−0.1695** (−3.91)		
SD5			−0.1282 (−1.43)	
RMSD5				−0.1307** (−3.83)
K_{t-1}	0.1302 (1.59)	0.2131* (2.60)	0.3312** (4.18)	0.2099* (2.53)
R^2	0.9332**	0.9270**	0.9194**	0.9267**
Durbin–Watson	2.06	2.08	2.15	2.07
N	130	130	130	130

Note: *t*-statistics in parentheses. * and** indicate significance at the 5% and 1% levels, respectively.

These are reasonable historical time frames for purposes of estimating forward-looking investor expectations of interest rate risk. Of course, if there has been little change in these S.D.s during the sample period, then none of this matters. However, as discussed in Berry (1995) there has been significant volatility in bond yields. This has led to sharp increases in S.D.s in the early 1980s (almost triple the level in the 1970s), with some decrease in the latter 1980s.

Another way of gauging this variability is to consider the deviation of the immediately preceding month's yield from the relevant prior months' yields. As in the case of S.D.s, 3- and 5-year lags were considered. For example, in the case of 3 years, the formula used to calculate the root mean square deviation (*RMSD*) in month *n* is

$$RMSD3(n) = \left(\left[\sum_{i=n-36}^{n-1} (YD_{n-1} - YD_i)^2 \right] / 36 \right)^{1/2} \tag{10}$$

where YD_{n-1} is the yield in the immediately preceding month and YD_i, $i = 1, \ldots, n-1$, corresponds to the yields in the prior months. An analogous formula for *RMSD* (*RMSD5*) was used for the case of 5 years. As in the cases for *SD3* and *SD5*, different data series were calculated for the four Moody's bond ratings and then averaged across bond ratings.

The *RMSD* may be an appropriate measure of the risk perceived by an investor since it measures the potential interest rate swings (based on prior months' interest rates) relative to the immediately preceding month's yield. In contrast, the variable S.D. measures interest variability over a prior time frame relative to the mean over that same time frame. That mean does not necessarily equal a current yield, and hence may underestimate investor perceptions with regard to potential interest rate variability. Thus, usage of the *RMSD* assumes that, in month *n*, investors may look at month $n-1$'s yield relative to prior months' interest rates to gauge the full impact of any potential interest rate swing. Note that, as discussed in Berry (1995) the trends in *RMSD* are similar to those of S.D.To comprehend for the possibility of a time trend in risk premia we included a monthly trend variable, *t*. This type of variable was discussed in Morin (1994), pp. 291–292) and was statistically significant there.

Our more complete formulation using *SD3* is then:

$$K_t^* = RP_t + YD_t \tag{11}$$

where

$$RP_t = \alpha + \beta t + \delta YD_t + \theta SD3_t. \tag{11a}$$

Assuming a regulator adjustment function as shown in Equation (3) and substituting Equations (11) and (11a) into Equation (3) produces our regression equation:

$$K_t = \alpha\gamma + \beta\gamma t + (\delta + 1)\gamma YD_t + \theta\gamma SD3_t + (1-\gamma)K_{t-1}. \tag{12}$$

Similar regression equations were used for *SD5*, *RMSD3* and *RMSD5*, where each of those variables were used in place of *SD3*. Our hypotheses are that the coefficient associated with *t* will be negative (consistent with Morin), the coefficient associated with *YD* will be positive, and that the coefficient associated with *SD3* (*SD5*, *RMSD3*, *RMSD5*) will be negative, as investors shift their relative preference to utility stock as interest rate risk on utility bonds increase.

Table 3. Implied Risk Premium Results, Dependent Variable = *RP*

Variable				
Constant	0.1238	0.1247	0.1181	0.1267
t	−0.0002	−0.0003	−0.0002	−0.0003
YD	−0.7029	−0.7418	−0.7089	−0.7532
SD3	−0.5849			
RMSD3		−0.2154		
SD5			−0.1917	
RMSD5				−0.1654

Table 5. Implied Risk Premium Results, Dependent Variable = *RP*

Variable				
Constant	0.1366	0.1390	0.1208	0.1408
t	−0.0004	−0.0003	−0.0002	−0.0003
GOV	−0.7906	−0.8169	−0.7399	−0.8215
SD3	−0.3357			
RMSD3		−0.1848		
SD5			0.1045	
RMSD5				−0.1655

The dependent variable, K, was then regressed on the three independent variables: time, yield and measures of variability in yields. Those four regression results are shown in Table 2.

Note that the regression slope coefficients are generally significant, although the coefficient for *SD5* was not. There is a statistically significant downward time trend, which is consistent with the result in Morin. The effects of *YD* on K are positive and significant. Three of the four coefficients associated with interest rate risk, *SD3*, *RMSD3* and *RMSD5* are significant and negative as was hypothesized. Finally, note that all of the slope coefficients associated with *YD* are significantly less than one, which supports the hypothesis that as interest rates decrease risk premia increase.

As can be seen in Table 2, the adjustment coefficients are in the range 67–87%, which are higher than the adjustment coefficient of 43% from Equation (5). This can be explained by noting that Equation (5) does not include the other factors shown in Table 2 (in particular, interest rate variability). Consequently, the adjustment coefficient measurement in Equation (5) is clouded by the effects of the other factors. It appears that regulators are not adjusting K to K^* very much (only 43%), simply because K is also reacting to other factors not captured in Equation (5). Table 2 properly captures those additional effects and isolates the larger adjustment coefficient effect.

The implied risk premium results, corresponding to Equation (11a), are shown in Table 3. As can be seen there, the coefficient associated with *YD* is between approximately −0.70 and −0.75. This indicates that each increase in utility bond yields of 100 basis points produces a decrease in the risk premium of 70 to 75 basis points. Increases in interest rates result in decreases in risk premia. Furthermore, the negative slope coefficients associated with interest rate risk, imply smaller risk premia as hypothesized. The trend variable in Table 3 has a negative slope, which is consistent with results reported in Morin (1994).[18]

To some extent the variable *YD* may include both the effects of general tightness or laxity in financial markets and interest rate risk. In order to better focus on the two separate factors, it would be appropriate to replace *YD* with *GOV* in

Table 4. Regression Results With *GOV*, Dependent Variable = K

Variable				
Constant	0.0781	0.0818	0.0639	0.0874
t	−0.0002** (−4.85)	−0.0002** (−5.10)	−0.0001** (−3.21)	−0.0002** (−5.44)
GOV	0.1197** (2.99)	0.1078** (2.66)	0.1376** (3.18)	0.1108** (2.80)
SD3	−0.1919 (−1.85)			
RMSD3		−0.1088* (−2.21)		
SD5			0.0553 (0.54)	
RMSD5				−0.1027** (−2.71)
K_{t-1}	0.4283** (5.30)	0.4113** (5.04)	0.4709** (6.01)	0.3794** (4.55)
R^2	0.9092**	0.9102**	0.9069**	0.9119**
Durbin–Watson	2.18	2.17	2.24	2.13
N	130	130	130	130

Note: *t*-statistics are in parentheses. * and ** indicate significance at the 5% and 1% levels, respectively.

Equations (11) and (11a), since *GOV* will more directly reflect changes in the supply and demand for loan funds, without the effect of utility bonds' interest rate risk. The corresponding equations with *SD3* are:

$$K_t^* = RP_t + GOV_t \tag{13}$$

$$RP_t = \alpha + \beta t + \delta GOV_t + \theta SD3_t \tag{13a}$$

These Equations focus on the relationship between utility stocks and government bonds. Assuming an adjustment mechanism as shown in Equation (3) a regression equation analogous to Equation (12) can be developed. Those regression results are shown in Table 4 and are similar to those from Table 2. However, note that the slope coefficients associated with *GOV* are smaller than those associated with *YD* in Table 2. This is consistent with the results in Berry (1995) wherein it was shown that *GOV* had a larger effect on utility bond yields than on utility common stock dividend yields. Given an imperfect, although positive, relationship between Treasury bonds and utility bonds, and an imperfect relationship between utility bonds and utility stocks, it naturally follows that there would be an even more imperfect relationship between Treasury bonds and utility stocks. This means that there is more substitutability between utility common stocks and utility bonds than between utility stocks and US Treasury bonds. A further point to note from Table 4 is that the slope coefficients associated with S.D. are statistically insignificant, while those associated with *RMSD* are significant.

The implied risk premium results, corresponding to Equation (13a) are shown in Table 5. As can be seen there, the coefficient associated with *GOV* is between approximately -0.74 and -0.82 less than those associated with *YD* in Table 3. This is consistent with the point raised above concerning relative substitutability between stocks and bonds. An increase in Treasury yields of 100 basis points produces an increase of 18–26 basis points in the cost of equity, and a corresponding decrease in the risk premium of 74–82 basis points. In sharp contrast to the reported results in Table 1, controlling for other factors, risk premia relative to Treasury yields are not necessarily stable, but change as Treasury yields change. Increases in Treasury yields result in decreases in risk premia, and those decreases are greater than those associated with similar increases in utility bond yields. Furthermore, the negative slope coefficients associated with utility bond interest rate risk, imply smaller risk premia as hypothesized. The trend variable in Table 5 has a negative slope, which is consistent with results reported in Morin (1994), as well as in Table 3.

CONCLUSIONS

This paper examined, through regression analysis, the possibility that there is an inverse relationship between risk premia and both interest rates and interest rate risk in the utility industry. We demonstrated that that is the case over the 1982–93 time period. Furthermore, it was shown that there is a statistically significant basis for asserting that risk premia increase as interest rates decrease. Our analysis also indicated that there was a downward time trend in risk premia in that period. All of these phenomena occurred with either utility bond yields or long-term US Treasury bond yields. However, for an equivalent increase in either utility bond yields or Treasury yields, required equity returns increase by a slightly greater amount with regard to utility bond yields.

It was also shown that regulators may exhibit an inertia in their setting of allowed returns, such that they move partially to the new required return, in the event capital conditions warrant a change. The degree of movement is in the range of 50–80% relative to the prior month's allowed return.

There are several policy implications from the above analysis. First, when regulators use the risk premium method for setting the allowed return on equity, they should consider the degree of recent interest rate variability and consequent interest rate risk, in comparing utility common stocks and utility bonds. The appropriate risk premium will be narrower the greater the interest rate risk. As demonstrated here, the better measure of interest rate risk is *RMSD*, not S.D. Second, objective regulators who attempt to utilize the risk premium method should implicitly compensate for the indicated regulator inertia. For example, calculate the risk premium using K^*, rather than K. Third, while Table 1 implies that risk premia relative to Treasury bonds are more stable, that is not the case when consideration is made for other factors, as shown in Tables 4 and 5. There is not necessarily any gain in precision in using a risk premium method based on Treasury bonds.

Fourth, if the US enters a period of relative stability in interest rates, we are likely to see utility risk premia increase, a phenomenon utility executives nor regulators have any degree of control over. This widening will not occur because of increases in required equity returns, but because of relatively lower interest rates and less interest rate risk.

NOTES

1. See Bonbright *et al.*, 1988 (pp. 317–28) for a discussion of these methods.
2. Gordon and Halpern (1976) show that an increase in variable and uncertain inflation will theoretically decrease the spread between bond and share yields. This acts through the Fisher effect and the resultant increase in interest rate uncertainty. Examples of rate cases where this argument has been made are Arkansas Public Service Commission (1987), Docket No. 87-070-U, Federal Energy Regulatory Commission (1986), Docket Nos. EL86-58-000 and EL86-59-000, Hawaii Public Utility Commission, Docket No. 4156, Kentucky Public Service Commission, Case No. 8045, and Pennsylvania Public Utility Commission, Docket R-811510.
3. These points are noted in Brigham *et al.* (1985) and Taylor and Peake (1982).
4. See Ibbotson Associates (1993), Carleton *et al.* (1983), Brigham *et al.* (1985) and Harris (1986) for a discussion of risk premia.
5. See Brennan (1982), Brigham *et al.* (1985) and Harris (1986). Other sources are Harris and Marston (1992), Gordon and Halpern (1976) and Federal Energy Regulatory Commission Staff (1992).
6. This approach was also taken in the Federal Energy Regulatory Commission (1992) Staff study.
7. During the same period, any interest rate risk associated with Treasury bonds was not as large, nor did it exhibit as large a decrease.
8. Given the rate case process (testimony, hearing, order writing) a 6 month lag is reasonable. However, if the 6 month period is either too long or short, the analysis here would only result in a mis-estimate of the intercept term, not the slope coefficients. For example, in a period of increasing interest rates(non-accelerating), if the appropriate lag should have been only 3 months, the 6 month lag will result in an over-estimate of the intercept term, but no mis-estimate of the slope terms. With a non-decelerating decrease in interest rates, the intercept term will be under-estimated, with no mis-estimated slope terms. The focus of this paper is on the slope terms. Furthermore, regression analyses was also performed using (a) bond yields contemporaneous with the date of the allowed return and (b) bond yields from 12 months earlier. In both those cases, the Durbin–Watson statistics were worse and the corresponding R^2 were less than with the 6 month lag. Additionally, the slope coefficients for the *YD* and *GOV* variables were not as large, nor as significant as in the 6 month lag case. Consequently, the 6 month lag scenario was utilized here.
9. For the electric and gas rate cases the data was from *Public Utilities Fortnightly's* 'Annual Surveys', while the telecommunications data was from *Public Utilities Fortnightly's* 'Selected Utility Rate Filings'.
10. The data was aggregated into monthly data for three reasons. First, Durbin–Watson statistics can then be sensibly calculated. Second, this approach is consistent with prior studies. Third, this aggregation facilitates the partial adjustment feature. There were months when there were no reported allowed returns, which decreased our total sample size.
11. See Johnston, 1972 (pp. 300–301), for discussion of this technique.
12. This approach implicitly assumes that regulators focus on allowed returns in other jurisdictions in the prior month. This is reasonable for two reasons. First, there is a certain amount of 'peer pressure' amongst regulators wherein they generally do not want their own jurisdiction's allowed returns to be out of line with other jurisdictions, unless justified by general financial and economic circumstances (such as changes in interest rates). Second, the last allowed rate of return for a particular utility may be anywhere from 6 months to 3 years earlier. Modelling those differing periods adds unnecessary complexity to the analysis, in light of the first point raised.
13. See Berry (1995) for an empirical investigation of the impact of interest rate variability on the level of interest rates.
14. Other explanations for an inverse relationship between interest rates and risk premia have to do with call provisions and tax rates. In a high interest rate environment firms will include more call provisions in new bond issues, for which bond investors require even higher interest rate compensation. Additionally, with increasing interest rates, the tax wedge applied to interest on bonds grows relative to that on common stock due to the favorable tax treatment on the capital gains component of stock returns.
15. It could also be attributable to increased utility credit risk during that period.
16. This effect can be readily observed in the DCF method where K is calculated as $D/P + g$. D is the expected dividend, P is the stock's market price, and g is the investor-expected long-term growth rate in dividends. As P increases because of investors' relative preference for utility stocks, K will decrease.
17. As shown in Berry (1995), the impact of the tightness of capital markets has differential effects on interest rates and common stock dividend yields.
18. This negative slope coefficient associated with the time variable also provides an explanation as to why the positive interest rate slope coefficients are

smaller in Table 3 than that reflected in Equation (2). Throughout the 1982–93 period, interest rates were generally decreasing, which according to the results in Table 3, will lead to decreases in required equity returns. However, during that same period the trend variable t was increasing. This increasing trend variable implies an additional source for decreases in required equity returns over that time period. Since Equation (2) does not explicitly separate out the trend variable, the overall effect in Equation (2) includes both of these effects, which will make the Equation (2) slope coefficient larger.

REFERENCES

Arkansas Public Service Commission (1987). Docket No. 87-070-U.

S.K. Berry (1995). Interest rate risk and utility bond and dividend yields. *Advances in Investment Analysis and Portfolio Management*, III, 183–191.

J.C. Bonbright, A. Albert and R.D. Kamerschen (1988). *Principles of Public Utility Rates*, Arlington, VA: Public Utilities Reports, Inc.

T.F. Brennan (1982). Does utility long-term debt really cost more than common equity? *Public Utilities Fortnightly*, February 18, 34–39.

E.F. Brigham, D.K. Shome and S.R. Vinson (1985). The risk premium approach to measuring a utility's cost of equity. *Financial Management*, Spring, 33–45.

W.T. Carleton, W. Chambers and J. Lakonishok (1983). Inflation risk and regulatory lag. *Journal of Finance*, May 1983, 419–431.

Federal Energy Regulatory Commission (1986). Docket Nos. EL86-58-000 and EL86-59-000.

Federal Energy Regulatory Commission Staff (1992). *Risk Premium Study*, August 4.

M.J. Gordon and P. Halpern (1976). Bond share yield spreads under uncertain inflation. *American Economic Review*, September, 559–565.

R.S. Harris (1986). Using analysts' growth forecasts to estimate shareholder required rate of return. *Financial Management*, Spring, 58–67.

R.S. Harris and F.C. Marston (1992). Estimating shareholder risk premia using analysts' growth forecasts. *Financial Management*, Summer, 63–70.

Hawaii Public Utility Commission. Docket No. 4156.

Ibbotson Associates (1993). *Stocks, Bonds, Bills, and Inflation, 1992 Yearbook*. Chicago: Ibbotson Associates.

J. Johnston (1972). *Econometric Methods*. 2nd edn., New York: McGraw-Hill.

Kentucky Public Service Commission. Case No. 8045.

Moody's Public Utility Manual (1982–93).

R.A. Morin (1994). *Regulatory Finance: Utilities' Cost of Capital*. Arlington, VA: Public Utilities Reports, Inc.

Pennsylvania Public Utility Commission. Docket R-811510.

Public Utilities Fortnightly (1983–93). Semi-annual editions.

G.T.C. Taylor and C.F. Peake (1982). A utility's cost of common equity may be less than its cost rate for new debt. *Public Utilities Fortnightly*, June 24, 23–30.