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CORPORATION COMMISSION
OF OKLAHOMA

BEFORE THE CORPORATION COMMISSION OF OKLAHOMA

IN THE MATTER OF THE APPLICATION OF)
OKLAHOMA GAS AND ELECTRIC COMPANY)
FOR AN ORDER OF THE COMMISSION)
AUTHORIZING APPLICANT TO MODIFY ITS)
RATES, CHARGES, AND TARIFFS FOR RETAIL)
ELECTRIC SERVICE IN OKLAHOMA)

CAUSE NO. PUD 201700496

Direct Testimony

of

Roger A. Morin, PhD

on behalf of

Oklahoma Gas and Electric Company

January 16, 2018

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EXHIBITS

Direct Exhibit RAM-1	Resume of Roger A. Morin
Direct Exhibit RAM-2	Investment-Grade Dividend-Paying Vertically Integrated Electric Utilities
Direct Exhibit RAM-3	Peer Group for OG&E
Direct Exhibit RAM-4	Investment-Grade Vertically Integrated Electric Utilities DCF Analysis: Value Line Growth Projections
Direct Exhibit RAM-5	Investment-Grade Vertically Integrated Electric Utilities DCF Analysis: Analysts' Growth Forecasts
Direct Exhibit RAM-6	Vertically Integrated Electric Utilities Beta Estimates
Direct Exhibit RAM-7	Utility Industry Historical Risk Premium Analysis
Direct Exhibit RAM-8	Allowed Risk Premium Electric Utilities
Direct Exhibit RAM-9	Proxy Group Capital Structures
Direct Exhibit RAM-10	Bond Rating Agencies' Financial Indicators

APPENDICES

Appendix A	CAPM, Empirical CAPM
Appendix B	Flotation Cost Allowance

I. INTRODUCTION AND SUMMARY OF RECOMMENDATION

1 Q. **Please state your name, business address, and occupation.**

2 A. My name is Dr. Roger A. Morin. My business address is Georgia State
3 University, Robinson College of Business, University Plaza, Atlanta, Georgia,
4 30303. I am Emeritus Professor of Finance at the Robinson College of Business,
5 Georgia State University and Professor of Finance for Regulated Industry at the
6 Center for the Study of Regulated Industry at Georgia State University. I am also
7 a principal in Utility Research International, an enterprise engaged in regulatory
8 finance and economics consulting to business and government. I am testifying on
9 behalf of OG&E, Inc. (OG&E or the Company).

10

11 Q. **Please describe your educational background.**

12 A. I hold a Bachelor of Engineering degree and an MBA in Finance from McGill
13 University, Montreal, Canada. I received my Ph.D. in Finance and Econometrics
14 at the Wharton School of Finance, University of Pennsylvania.

15

16 Q. **Please summarize your academic and business career.**

17 A. I have taught at the Wharton School of Finance, University of Pennsylvania,
18 Amos Tuck School of Business at Dartmouth College, Drexel University,
19 University of Montreal, McGill University, and Georgia State University. I was a
20 faculty member of Advanced Management Research International, The
21 Management Exchange Inc., Exnet, Inc. I am now a faculty member of S&P
22 Global Intelligence (formerly SNL Knowledge Center or SNL), where I continue
23 to conduct frequent national executive-level education seminars throughout the
24 United States and Canada. In the last 30 years, I have conducted numerous
25 national seminars on “Utility Finance,” “Utility Cost of Capital,” “Alternative
26 Regulatory Frameworks,” and “Utility Capital Allocation,” which I have
27 developed on behalf of the aforementioned institutions.

28 I have authored or co-authored several books, monographs, and articles in
29 academic scientific journals on the subject of finance. They have appeared in a

1 variety of journals, including The Journal of Finance, The Journal of Business
2 Administration, International Management Review, and Public Utilities
3 Fortnightly. I published a widely-used treatise on regulatory finance, Utilities'
4 Cost of Capital, Public Utilities Reports, Inc., Arlington, Va. 1984. In late 1994,
5 the same publisher released my book, Regulatory Finance, a voluminous treatise
6 on the application of finance to regulated utilities. A revised and expanded
7 edition of this book, The New Regulatory Finance, was published in 2006. I have
8 been engaged in extensive consulting activities on behalf of numerous
9 corporations, legal firms, and regulatory bodies in matters of financial
10 management and corporate litigation.

11 Please see Direct Exhibit RAM-1 for my professional qualifications.

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1 Q. **Have you previously testified on cost of capital before utility regulatory**
2 **commissions?**

3 A. Yes, I have been a cost of capital witness before nearly 50 regulatory bodies in
4 North America, including the Oklahoma Corporation Commission (“OCC” or
5 “Commission”) and the Federal Energy Regulatory Commission. I have testified
6 before the following state, provincial, and other local regulatory commissions:

7

Alabama	Florida	Montana	Oregon
Alaska	Georgia	Nebraska	Pennsylvania
Alberta	Hawaii	Nevada	Quebec
Arizona	Illinois	New Brunswick	South Carolina
Arkansas	Indiana	New Hampshire	South Dakota
British Columbia	Iowa	New Jersey	Tennessee
California	Louisiana	New Mexico	Texas
City of New Orleans	Maine	New York	Utah
Colorado	Manitoba	Newfoundland	Vermont
CRTC	Maryland	North Carolina	Virginia
Delaware	Michigan	North Dakota	West Virginia
District of Columbia	Minnesota	Nova Scotia	Wisconsin
FCC	Mississippi	Oklahoma	
FERC	Missouri	Ontario	

8 The details of my participation in regulatory proceedings are also provided
9 in Direct Exhibit RAM-1.

10

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

12 A. The purpose of my testimony in this proceeding is to present an independent
13 appraisal of the fair and reasonable rate of return on common equity (ROE) on the
14 common equity capital invested in Oklahoma Gas and Electric Company, Inc.’s
15 (“OG&E” or the “Company”) electric utility operations in the State of Oklahoma.

1 Based upon this appraisal, I have formed my professional judgment as to a return
2 on such capital that would:

- 3 (1) be fair to ratepayers;
- 4 (2) allow OG&E to attract the capital needed for
5 infrastructure and reliability investments on reasonable terms;
- 6 (3) maintain OG&E's financial integrity; and
- 7 (4) be comparable to returns offered on comparable risk investments.

8

9 **Q. Please briefly identify the exhibits and appendices accompanying your**
10 **testimony.**

11 A. I have attached to my testimony Direct Exhibit RAM-1 through Direct Exhibit
12 RAM-10, and Appendices A and B. These Exhibits and appendices relate directly
13 to points in my testimony, and are described in further detail in connection with
14 the discussion of those points in my testimony.

15

16 **Q. Please summarize your results and recommendations.**

17 A. My testimony demonstrates the following:

18 1) In order to arrive at my final recommended ROE, I applied several
19 traditional financial models to a group of electric utilities comparable in risk to
20 OG&E, including Discounted Cash Flow (DCF) analyses, Capital Asset Pricing
21 Model (CAPM) analyses, and Risk Premium analyses. I use the average result of
22 9.9% obtained from these multiple analyses as my recommended ROE for
23 OG&E. A ROE of 9.9% for OG&E is required in order for the Company to: (i)
24 attract capital on reasonable terms, (ii) maintain its financial integrity, and (iii)
25 earn a return commensurate with returns on comparable risk investments.

26 2) I demonstrate that the Company's test year capital structure consisting
27 of approximately 53% common equity capital is reasonable for ratemaking
28 purposes for two reasons. First, it is consistent with the actual capital structures
29 of the operating electric utility companies in my comparable group of electric
30 utilities. The average common equity ratio of these companies in 2017 is 53%,

1 the same as the Company's. Second, it is consistent with the credit agencies'
2 financial ratio benchmarks for a single A bond rating which I consider optimal
3 and cost efficient for ratepayers.

4 3) I describe the negative consequences of imputing a capital structure
5 different from the company's actual capital structure and consisting of more debt.

6 4) I demonstrate the need for both the Company and its ratepayers to
7 retain the Company's single A bond rating which is predicated in part on its
8 robust balance sheet. A strong single A bond rating minimizes the pre-tax cost of
9 capital to ratepayers.

10 5) I describe the serious concerns expressed by several members of the
11 investment community regarding their perception of a deterioration in the quality
12 of Oklahoma regulation. Moody's downgrade of the Company's credit rating is
13 noteworthy in that regard. I discuss the serious consequences of a downgrade of
14 the Company's bonds, and the crucial role of my recommended ROE in avoiding
15 such a downgrade. The consequences include a substantial increase in ratepayer
16 burden, an increase in both the cost of debt and common equity, and a capital loss
17 incurred by existing bondholders. I stress the importance through supportive
18 regulation of avoiding these consequences and the need to retain the Company's
19 single A bond rating which I consider cost efficient for both ratepayers and
20 investors.

21
22 **Q. Would it be in the best interests of ratepayers for the Commission to approve**
23 **a ROE of 9.9% for OG&E electric utility operations?**

24 **A.** Yes. My analysis shows that this return attracts the capital needed for utility
25 infrastructure and reliability capital investments, fairly compensates investors, and
26 maintains OG&E's credit strength. Adopting a lower ROE would increase costs
27 for ratepayers.

28
29 **Q. Please explain how low allowed ROEs can increase both the future**
30 **cost of capital and the cost of service to ratepayer.**

1 A. If a utility is authorized a ROE below the level required by equity investors, the
2 utility or its parent will find it difficult to access equity capital. Investors will not
3 provide equity capital at the current market price if the earnable return on equity
4 is below the level they require given the risks of an equity investment in the
5 utility. The equity market corrects this by generating a stock price in equilibrium
6 that reflects the valuation of the potential earnings stream from an equity
7 investment at the risk-adjusted return equity investors require. In the case of a
8 utility that has been authorized a return below the level investors believe is
9 appropriate for the risk they bear, the result is a decrease in the utility's market
10 price per share of common stock. This reduces the financial viability of equity
11 financing in two ways. First, because the utility's price per share of common
12 stock decreases, the net proceeds from issuing common stock are reduced.
13 Second, since the utility's market to book ratio decreases with the decrease in the
14 share price of common stock, the potential risk from dilution of equity
15 investments reduces investors' inclination to purchase new issues of common
16 stock. The ultimate effect is the utility will have to rely more on debt financing to
17 meet its capital needs.

18 As a company relies more on debt financing, its capital structure becomes
19 more leveraged. Because debt payments are a fixed financial obligation to the
20 utility, and income available to common equity is subordinate to fixed charges,
21 this decreases the operating income available for dividend and earnings growth.
22 Consequently, equity investors face greater uncertainty about future dividends and
23 earnings from the firm. As a result, the firm's equity becomes a riskier
24 investment. The risk of default on a company's bonds also increases, making the
25 utility's debt a riskier investment. This increases the cost to the utility from both
26 debt and equity financing and increases the possibility a company will not have
27 access to the capital markets for its outside financing needs. Ultimately, to ensure
28 that OG&E has access to capital markets for its capital needs, a fair and
29 reasonable authorized ROE of 9.9% is required.

30 OG&E must secure outside funds from capital markets to finance required
31 utility plant and equipment investments irrespective of capital market conditions,

1 interest rate conditions and the quality consciousness of market participants.
2 Thus, rate relief requirements and supportive regulatory treatment, including
3 approval of my recommended ROE, are essential requirements.
4

5 **Q. Please describe how the remainder of your testimony is organized.**

6 **A.** The remainder of my testimony is divided into five broad sections:

- 7 (ii) Regulatory Framework and Rate of Return;
- 8 (iii) Cost of Equity Capital Estimates;
- 9 (iv) Summary and Recommendation on Cost of Equity;
- 10 (v) Capital Structure.
- 11 (vi) Optimal Bond Rating and Capital Structure.

12
13 Section II discusses the rudiments of rate of return regulation and the basic
14 notions underlying rate of return. Section III contains the application of DCF,
15 Risk Premium, and CAPM tests. In Section IV, the results from the various
16 approaches used in determining a fair return for OG&E are summarized. Section
17 V addresses the issue of an optimal capital structure and the adequacy of the
18 Company's common equity ratio. The last section discusses the issue of an
19 optimal bond rating and cost efficient capital structure.
20

II. REGULATORY FRAMEWORK AND RATE OF RETURN

21 **Q. Please explain how a regulated company's rates should be set under**
22 **traditional cost of service regulation.**

23 **A.** Under the traditional regulatory process, a regulated company's rates should be
24 set so that the company recovers its costs, including taxes and depreciation, plus a
25 fair and reasonable return on its invested capital. The allowed rate of return must
26 necessarily reflect the cost of the funds obtained, that is, investors' return
27 requirements. In determining a company's required rate of return, the starting
28 point is investors' return requirements in financial markets. A rate of return can
29 then be set at a level sufficient to enable a company to earn a return
30 commensurate with the cost of those funds.

1 Funds can be obtained in two general forms, debt capital and equity
2 capital. The cost of debt funds can be easily ascertained from an examination of
3 the contractual interest payments. The cost of common equity funds (i.e.,
4 investors' required rate of return) is more difficult to estimate. It is the purpose of
5 the next section of my testimony to estimate fair and reasonable ROE ranges for
6 OG&E's cost of common equity capital.

7
8 **Q. What fundamental principles underlie the determination of a fair and**
9 **reasonable ROE?**

10 A. The heart of utility regulation is the setting of just and reasonable rates by way of
11 a fair and reasonable return. There are two landmark United States Supreme
12 Court cases that define the legal principles underlying the regulation of a public
13 utility's rate of return and provide the foundations for the notion of a fair return:

- 14
15 1. *Bluefield Water Works & Improvement Co. v. Public*
16 *Service Commission of West Virginia*, 262 U.S. 679 (1923);
17 and
- 18 2. *Federal Power Commission v. Hope Natural Gas Co.*,
19 320 U.S. 591 (1944).
20

21 The *Bluefield* case set the standard against which just and reasonable rates of
22 return are measured:

23 A public utility is entitled to such rates as will permit it to earn a
24 return on the value of the property which it employs for the
25 convenience of the public *equal to that generally being made at*
26 *the same time and in the same general part of the country on*
27 *investments in other business undertakings which are attended by*
28 *corresponding risks and uncertainties ... The return should be*
29 *reasonable*, sufficient to assure confidence in the financial
30 soundness of the utility, and should be adequate, under efficient
31 and economical management, to *maintain and support its credit*
32 and *enable it to raise money* necessary for the proper discharge of
33 its public duties.

34 *Bluefield Water Works & Improvement Co.*, 262 U.S. at 692 (emphasis added).

1 The *Hope* case expanded on the guidelines to be used to assess the
2 reasonableness of the allowed return. The Court reemphasized its statements in
3 the *Bluefield* case and recognized that revenues must cover “capital costs.” The
4 Court stated:

5 From the investor or company point of view it is important that
6 there be enough revenue not only for operating expenses but also
7 for the capital costs of the business. These include service on the
8 debt and dividends on the stock ... By that standard *the return to*
9 *the equity owner should be commensurate with returns on*
10 *investments in other enterprises having corresponding risks.* That
11 return, moreover, should be sufficient to *assure confidence in the*
12 *financial integrity of the enterprise, so as to maintain its credit and*
13 *attract capital.*

14 *Hope Natural Gas Co.*, 320 U.S. at 603 (emphasis added).

15 The United States Supreme Court reiterated the criteria set forth in *Hope*
16 in *Federal Power Commission v. Memphis Light, Gas & Water Division*, 411 U.S.
17 458 (1973); in *Permian Basin Rate Cases*, 390 U.S. 747 (1968); and, most
18 recently, in *Duquesne Light Co. v. Barasch*, 488 U.S. 299 (1989). In the *Permian*
19 *Basin Rate Cases*, the Supreme Court stressed that a regulatory agency’s rate of
20 return order should:

21 reasonably be expected to maintain financial integrity, attract
22 necessary capital, and fairly compensate investors for the risks they
23 have assumed.

24 *Permian Basin Rate Cases*, 390 U.S. at 792.

25 Therefore, the “end result” of this Commission’s decision should be to
26 allow OG&E the opportunity to earn a return on equity that is:

- 27 (i) commensurate with returns on investments in other firms
28 having corresponding risks;
- 29 (ii) sufficient to assure confidence in OG&E’s financial
30 integrity; and
- 31 (iii) sufficient to maintain OG&E’s creditworthiness and ability
32 to attract capital on reasonable terms.

1 Q. **How is the fair rate of return determined?**

2 A. The aggregate return required by investors is called the “cost of capital.” The cost
3 of capital is the opportunity cost, expressed in percentage terms, of the total pool
4 of capital employed by the utility. It is the composite weighted cost of the various
5 classes of capital (e.g., bonds, preferred stock, common stock) used by the utility,
6 with the weights reflecting the proportions of the total capital that each class of
7 capital represents. The fair return in dollars is obtained by multiplying the rate of
8 return set by the regulator by the utility’s “rate base.” The rate base is essentially
9 the net book value of the utility’s plant and other assets used to provide utility
10 service in a particular jurisdiction.

11 Although utilities like OG&E enjoy varying degrees of monopoly in the
12 sale of public utility services, they (or their parent companies) must compete with
13 everyone else in the free, open market for the input factors of production, whether
14 labor, materials, machines, or capital, including the capital investments required
15 to support the utility infrastructure. The prices of these inputs are set in the
16 competitive marketplace by supply and demand, and it is these input prices that
17 are incorporated in the cost of service computation. This is just as true for capital
18 as for any other factor of production. Since utilities and other investor-owned
19 businesses must go to the open capital market and sell their securities in
20 competition with every other issuer, there is obviously a market price to pay for
21 the capital they require (e.g., the interest on debt capital or the expected return on
22 equity). In order to attract the necessary capital, utilities must compete with
23 alternative uses of capital and offer a return commensurate with the associated
24 risks.

25

26 Q. **How does the concept of a fair return relate to the concept of opportunity
27 cost?**

28 A. The concept of a fair return is intimately related to the economic concept of
29 “opportunity cost.” When investors supply funds to a utility by buying its stocks
30 or bonds, they are not only postponing consumption, giving up the alternative of
31 spending their dollars in some other way, they are also exposing their funds to

1 risk and forgoing returns from investing their money in alternative comparable
2 risk investments. The compensation they require is the price of capital. If there
3 are differences in the risk of the investments, competition among firms for a
4 limited supply of capital will bring different prices. The capital markets translate
5 these differences in risk into differences in required return, in much the same way
6 that differences in the characteristics of commodities are reflected in different
7 prices.

8 The important point is that the required return on capital is set by supply
9 and demand and is influenced by the relationship between the risk and return
10 expected for those securities and the risks expected from the overall menu of
11 available securities.

12

13 **Q. What economic and financial concepts have guided your assessment of**
14 **OG&E's cost of common equity?**

15 **A.** Two fundamental economic principles underlie the appraisal of OG&E's cost of
16 equity, one relating to the supply side of capital markets, the other to the demand
17 side.

18 On the supply side, the first principle asserts that rational investors
19 maximize the performance of their portfolios only if they expect the returns on
20 investments of comparable risk to be the same. If not, rational investors will
21 switch out of those investments yielding lower returns at a given risk level in
22 favor of those investment activities offering higher returns for the same degree of
23 risk. This principle implies that a company will be unable to attract capital funds
24 unless it can offer returns to capital suppliers that are comparable to those
25 achieved on competing investments of similar risk.

26 On the demand side, the second principle asserts that a company will
27 continue to invest in real physical assets if the return on these investments equals,
28 or exceeds, a company's cost of capital. This principle suggests that a regulatory
29 board should set rates at a level sufficient to create equality between the return on
30 physical asset investments and a company's cost of capital.

31

1 Q. **How does OG&E obtain its capital and how is its overall cost of capital**
2 **determined?**

3 A. The funds employed by OG&E are obtained in two general forms, debt capital
4 and equity capital. The cost of debt funds can be ascertained easily from an
5 examination of the contractual interest payments. The cost of common equity
6 funds, that is, equity investors' required rate of return, is more difficult to estimate
7 because the dividend payments received from common stock are not contractual
8 or guaranteed in nature. They are uneven and risky, unlike interest payments.
9 Once a cost of common equity estimate has been developed, it can then easily be
10 combined with the embedded cost of debt based on the utility's capital structure,
11 in order to arrive at the overall cost of capital (overall rate of return).

12

13 Q. **What is the market required rate of return on equity capital?**

14 A. The market required rate of return on common equity, or cost of equity, is the
15 return demanded by the equity investor. Investors establish the price for equity
16 capital through their buying and selling decisions in capital markets. Investors set
17 return requirements according to their perception of the risks inherent in the
18 investment, recognizing the opportunity cost of forgone investments in other
19 companies, and the returns available from other investments of comparable risk.

20

21 Q. **What must be considered in estimating a fair ROE?**

22 A. The basic premise is that the allowable ROE should be commensurate with
23 returns on investments in other firms having corresponding risks. The allowed
24 return should be sufficient to assure confidence in the financial integrity of the
25 firm, in order to maintain creditworthiness and ability to attract capital on
26 reasonable terms. The "attraction of capital" standard focuses on investors' return
27 requirements that are generally determined using market value methods, such as
28 the DCF, CAPM, or risk premium methods. These market value tests define "fair
29 return" as the return investors anticipate when they purchase equity shares of
30 comparable risk in the financial marketplace. This is a market rate of return,
31 defined in terms of anticipated dividends and capital gains as determined by

1 expected changes in stock prices, and reflects the opportunity cost of capital. The
2 economic basis for market value tests is that new capital will be attracted to a firm
3 only if the return expected by the suppliers of funds is commensurate with that
4 available from alternative investments of comparable risk.
5

6 III. COST OF EQUITY CAPITAL ESTIMATES

7 Q. **How did you estimate a fair ROE for OG&E?**

8 A. To estimate a fair ROE for OG&E, I employed three methodologies:

9 (i) DCF methodology;

10 (ii) CAPM methodology; and

11 (iii) Risk Premium methodology.

12 All three methodologies are market-based methodologies designed to estimate the
13 return required by investors on the common equity capital committed to OG&E.
14

15 Q. **Why did you use more than one approach for estimating the cost of equity?**

16 A. No one single method provides the necessary level of precision for determining a
17 fair return, but each method provides useful evidence to facilitate the exercise of
18 an informed judgment. Reliance on any single method or preset formula is
19 inappropriate when dealing with investor expectations because of possible
20 measurement difficulties and vagaries in individual companies' market data.
21 Examples of such vagaries include dividend suspension, insufficient or
22 unrepresentative historical data due to a recent merger, impending merger or
23 acquisition, and a new corporate identity due to restructuring activities. The
24 advantage of using several different approaches is that the results of each one can
25 be used to check the others.

26 As a general proposition, it is extremely dangerous to rely on only one
27 generic methodology to estimate equity costs. The difficulty is compounded
28 when only one variant of that methodology is employed. It is compounded even
29 further when that one methodology is applied to a single company. Hence,

1 several methodologies applied to several comparable risk companies should be
2 employed to estimate the cost of common equity.

3 As I have stated, there are three broad generic methods available to
4 measure the cost of equity: DCF, CAPM, and risk premium. All three of these
5 methods are accepted and used by the financial community and firmly supported
6 in the financial literature. The weight accorded to any one method may vary
7 depending on unusual circumstances in capital market conditions.

8 Each methodology requires the exercise of considerable judgment on the
9 reasonableness of the assumptions underlying the method and on the
10 reasonableness of the proxies used to validate the theory and apply the method.
11 Each method has its own way of examining investor behavior, its own premises,
12 and its own set of simplifications of reality. Investors do not necessarily
13 subscribe to any one method, nor does the stock price reflect the application of
14 any one single method by the price-setting investor. There is no guarantee that a
15 single DCF result is necessarily the ideal predictor of the stock price and of the
16 cost of equity reflected in that price, just as there is no guarantee that a single
17 CAPM or risk premium result constitutes the perfect explanation of a stock's
18 price or the cost of equity.

19 **Q. Are there any practical difficulties in applying cost of capital methodologies**
20 **in environments of volatility in capital markets and economic uncertainty?**

21 **A.** Yes, there are. The traditional cost of equity estimation methodologies are
22 difficult to implement when you are dealing with instability and volatility in the
23 capital markets and the uncertain economy both in the U.S. and abroad. This is
24 not only because stock prices are volatile at this time, but also because utility
25 company historical data have become less meaningful for an industry
26 experiencing substantial change, for example, the transition to stringent renewable
27 standards and the need to secure vast amounts of external capital over the next
28 decade, regardless of capital market conditions. Past earnings and dividend trends
29 may simply not be indicative of the future. For example, historical growth rates
30 of earnings and dividends have been depressed by eroding margins due to a
31 variety of factors, including the sluggish economy, declining customer usage,

1 restructuring, historically low interest rates and falling margins. As a result, this
2 historical data may not be representative of the future long-term earning power of
3 these companies. Moreover, historical growth rates may not be necessarily
4 representative of future trends for several electric utilities involved in mergers and
5 acquisitions, as these companies going forward are not the same companies for
6 which historical data are available.

7 In short, given volatility in capital markets and economic uncertainties, the
8 utilization of multiple methodologies is critical, and reliance on a single
9 methodology is highly hazardous.

10
A. DCF Estimates

11 **Q. Please describe the DCF approach to estimating the cost of equity capital.**

12 **A.** According to DCF theory, the value of any security to an investor is the expected
13 discounted value of the future stream of dividends or other benefits. One widely
14 used method to measure these anticipated benefits in the case of a non-static
15 company is to examine the current dividend plus the increases in future dividend
16 payments expected by investors. This valuation process can be represented by the
17 following formula, which is the traditional DCF model:

18
$$K_e = D_1/P_0 + g$$

19
20 where: K_e = investors' expected return on equity

21 D_1 = expected dividend at the end of the coming year

22 P_0 = current stock price

23 g = expected growth rate of dividends, earnings, stock
24 price, and book value

25
26 The traditional DCF formula states that under certain assumptions, which
27 are described in the next paragraph, the equity investor's expected return (K_e) can
28 be viewed as the sum of an expected dividend yield (D_1/P_0) plus the expected
29 growth rate of future dividends and stock price (g). The returns anticipated at a
30 given market price are not directly observable and must be estimated from

1 statistical market information. The idea of the market value approach is to infer
2 K_e from the observed share price, the observed dividend, and an estimate of
3 investors' expected future growth.

4 The assumptions underlying this valuation formulation are well known,
5 and are discussed in detail in Chapter 8 of my reference text, *The New Regulatory*
6 *Finance*. The standard DCF model requires the following main assumptions:

- 7 (i) a constant average growth trend for both dividends and
8 earnings;
- 9 (ii) a stable dividend payout policy;
- 10 (iii) a discount rate in excess of the expected growth rate; and
- 11 (iv) a constant price-earnings multiple, which implies that
12 growth in price is synonymous with growth in earnings and
13 dividends.

14 The standard DCF model also assumes that dividends are paid at the end of each
15 year when in fact dividend payments are normally made on a quarterly basis.

16 Q. **How did you estimate OG&E's cost of equity with the DCF model?**

17 A. In estimating OG&E's cost of equity, I applied the DCF model to a group of
18 investment-grade, dividend-paying, vertically integrated electric utilities with the
19 majority of their revenues from regulated operations that are covered in the Value
20 Line database.

21 In order to apply the DCF model, two components are required: the
22 expected dividend yield (D_1/P_0), and the expected long-term growth (g). The
23 expected dividend (D_1) in the annual DCF model can be obtained by multiplying
24 the current indicated annual dividend rate by the growth factor ($1 + g$).
25

1 Q. **How did you estimate the dividend yield component of the DCF model?**

2 A. In implementing the DCF model, I have used the dividend yields reported in the
3 Value Line Investment Reports for each company in the peer group¹. Basing
4 dividend yields on average results from a large group of companies reduces the
5 concern that the vagaries of individual company stock prices will result in an
6 unrepresentative dividend yield.

7
8 Q. **Why did you multiply the spot dividend yield by $(1 + g)$ rather than by $(1 + 0.5g)$?**

9
10 A. Some analysts multiply the spot dividend yield by one plus one half the expected
11 growth rate $(1 + 0.5g)$ rather than the conventional one plus the expected growth
12 rate $(1 + g)$. This procedure understates the return expected by the investor.

13 The fundamental assumption of the basic annual DCF model is that
14 dividends are received annually at the end of each year and that the first dividend
15 is to be received one year from now. Thus, the appropriate dividend to use in a
16 DCF model is the full prospective dividend to be received at the end of the year.
17 Since the appropriate dividend to use in a DCF model is the prospective dividend
18 one year from now rather than the dividend one-half year from now, multiplying
19 the spot dividend yield by $(1 + 0.5g)$ understates the proper dividend yield.

20 Moreover, the basic annual DCF model ignores the time value of quarterly
21 dividend payments and assumes dividends are paid once a year at the end of the
22 year. Multiplying the spot dividend yield by $(1 + g)$ is actually a conservative
23 attempt to capture the reality of quarterly dividend payments. Use of this method
24 is conservative in the sense that the annual DCF model fully ignores the more
25 frequent compounding of quarterly dividends.

26

¹ Value Line reports for each company in the peer group are available in my workpapers.

1 Q. **How did you estimate the growth component of the DCF model?**

2 A. The principal difficulty in calculating the required return by the DCF approach is
3 in ascertaining the growth rate that investors currently expect. Since no explicit
4 estimate of expected growth is observable, proxies must be employed.

5 As proxies for expected growth, I examined the consensus growth
6 estimate developed by professional analysts. Projected long-term growth rates
7 actually used by institutional investors to determine the desirability of investing in
8 different securities influence investors' growth anticipations. These forecasts are
9 made by large reputable organizations, and the data are readily available and are
10 representative of the consensus view of investors. Because of the dominance of
11 institutional investors in investment management and security selection, and their
12 influence on individual investment decisions, analysts' growth forecasts influence
13 investor growth expectations and provide a sound basis for estimating the cost of
14 equity with the DCF model.

15 Growth rate forecasts of several analysts are available from published
16 investment newsletters and from systematic compilations of analysts' forecasts,
17 such as those tabulated by Zacks Investment Research Inc. ("Zacks") and Yahoo
18 Finance. I used Value Line's growth forecasts as well as analysts' long-term
19 growth forecasts reported in Zacks as proxies for investors' growth expectations
20 in applying the DCF model.

21

22 Q. **Why did you reject the use of historical growth rates in applying the DCF
23 model to utilities?**

24 A. I have rejected historical growth rates as proxies for expected growth in the DCF
25 calculation for two reasons. First, historical growth patterns are already
26 incorporated in analysts' growth forecasts that should be used in the DCF model,
27 and are therefore redundant. Second, published studies in the academic literature
28 demonstrate that growth forecasts made by security analysts are reasonable
29 indicators of investor expectations, and that investors rely on analysts' forecasts.
30 This considerable literature is summarized in Chapter 9 of my most recent
31 textbook, *The New Regulatory Finance*.

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Q. **Did you consider any other method of estimating expected growth to apply the DCF model?**

A. Yes, I did. I considered using the so-called “sustainable growth” method, also referred to as the “retention growth” method. According to this method, future growth is estimated by multiplying the fraction of earnings expected to be retained by the company, ‘b’, by the expected return on book equity, ROE, as follows:

$$g = b \times \text{ROE}$$

where: g = expected growth rate in earnings/dividends

b = expected retention ratio

ROE = expected return on book equity

Q. **Do you have any reservations in regards to the sustainable growth method?**

A. Yes, I do. First, the sustainable method of predicting growth contains a logic trap: the method requires an estimate of expected return on book equity to be implemented. But if the expected return on book equity input required by the model differs from the recommended return on equity, a fundamental contradiction in logic follows. Second, the empirical finance literature demonstrates that the sustainable growth method of determining growth is not as significantly correlated to measures of value, such as stock prices and price/earnings ratios, as analysts’ growth forecasts. I therefore chose not to rely on this method.

Q. **Did you consider dividend growth in applying the DCF model?**

A. No, not at this time. The reason is that as a practical matter, while there is an abundance of earnings growth forecasts, there are very few forecasts of dividend growth. Moreover, it is growth in earnings that will support future dividends and share prices.

1 Q. **Is there any empirical evidence documenting the importance of earnings in**
2 **evaluating investors' expectations?**

3 A. Yes, there is an abundance of evidence attesting to the importance of earnings in
4 assessing investors' expectations. First, the sheer volume of earnings forecasts
5 available from the investment community relative to the scarcity of dividend
6 forecasts attests to their importance. To illustrate, Value Line, Yahoo Finance,
7 Zacks Investment, First Call Thompson, Reuters, and Multex provide
8 comprehensive compilations of investors' earnings forecasts. The fact that these
9 investment information providers focus on growth in earnings rather than growth
10 in dividends indicates that the investment community regards earnings growth as
11 a superior indicator of future long-term growth. Second, Value Line's principal
12 investment rating assigned to individual stocks, Timeliness Rank, is based
13 primarily on earnings, which accounts for 65% of the ranking.

14

15 Q. **How did you approach the composition of comparable groups in order to**
16 **estimate OG&E's cost of equity with the DCF method?**

17 A. Because OG&E is a wholly-owned subsidiary of OGE Energy Corp. and is not
18 publicly traded, the DCF model cannot be applied to OG&E, and proxies must be
19 used. There are two possible approaches in forming proxy groups of companies.

20 The first approach is to apply cost of capital estimation techniques to a
21 select group of companies directly comparable in risk to OG&E. These
22 companies are chosen by the application of stringent screening criteria to a
23 universe of utility stocks in an attempt to identify companies with the same
24 investment risk as OG&E. Examples of screening criteria include bond rating,
25 beta risk, size, percentage of revenues from utility operations, and common equity
26 ratio. The end result is a small sample of companies with a risk profile similar to
27 that of OG&E, provided the screening criteria are defined and applied correctly.

28 The second approach is to apply cost of capital estimation techniques to a
29 large group of utilities representative of the utility industry average and then make
30 adjustments to account for any difference in investment risk between the company

1 and the industry average, if any. As explained below, in view of substantial
2 changes in circumstances in the utility industry, I have chosen the latter approach.

3 In the uncertain capital market and industry environment, it is important to
4 select relatively large sample sizes representative of the utility industry as a
5 whole, as opposed to small sample sizes consisting of a handful of companies.
6 This is because the equity market as a whole and utility industry capital market
7 data are volatile. As a result of this volatility, the composition of small groups of
8 companies is very fluid, with companies exiting the sample due to dividend
9 suspensions or reductions, insufficient or unrepresentative historical data due to
10 recent mergers, impending merger or acquisition, and changing corporate
11 identities due to restructuring activities.

12 From a statistical standpoint, confidence in the reliability of the DCF
13 model result is considerably enhanced when applying the DCF model to a large
14 group of companies. Any distortions introduced by measurement errors in the
15 two DCF components of equity return for individual companies, namely dividend
16 yield and growth are mitigated. Utilizing a large portfolio of companies reduces
17 the influence of either overestimating or underestimating the cost of equity for
18 any one individual company. For example, in a large group of companies,
19 positive and negative deviations from the expected growth will tend to cancel out
20 owing to the law of large numbers, provided that the errors are independent.² The
21 average growth rate of several companies is less likely to diverge from expected
22 growth than is the estimate of growth for a single firm. More generally, the

2 If σ_i^2 represents the average variance of the errors in a group of N companies, and σ_{ij} the average covariance between the errors, then the variance of the error for the group of N companies, σ_N^2 is:

$$\sigma_N^2 = \frac{1}{N} \sigma_i^2 + \frac{N-1}{N} \sigma_{ij}$$

If the errors are independent, the covariance between them (σ_{ij}) is zero, and the variance of the error for the group is reduced to:

$$\sigma_N^2 = \frac{1}{N} \sigma_i^2$$

As N gets progressively larger, the variance gets smaller and smaller.

1 assumptions of the DCF model are more likely to be fulfilled for a large group of
2 companies than for any single firm or for a small group of companies.

3 Moreover, small samples are subject to measurement error, and in
4 violation of the Central Limit Theorem of statistics.³ From a statistical
5 standpoint, reliance on robust sample sizes mitigates the impact of possible
6 measurement errors and vagaries in individual companies' market data.
7 Examples of such vagaries include dividend suspension, insufficient or
8 unrepresentative historical data due to a recent merger, impending merger or
9 acquisition, and a new corporate identity due to restructuring.

10 The point of all this is that the use of a handful of companies in a highly
11 fluid and unstable industry produces fragile and statistically unreliable results. A
12 far safer procedure is to employ large sample sizes representative of the industry
13 as a whole and apply subsequent risk adjustments to the extent that the company's
14 risk profile differs from that of the industry average.

15
16 **Q. Can you describe the proxy group for OG&E's electric utility business?**

17 **A.** As proxies for OG&E, I examined a group of investment-grade dividend-paying
18 vertically integrated electric utilities covered in Value Line's Electric Utility
19 industry group, meaning that these companies all possess utility assets similar to
20 OG&E's. I began with all the parent companies of those electric utility operating
21 companies designated as vertically integrated electric utilities by Moody's⁴ that
22 are also covered in the Value Line Survey as shown on Direct Exhibit RAM-2.

3 The Central Limit Theorem describes the characteristics of the distribution of values we would obtain if we were able to draw an infinite number of random samples of a given size from a given population and we calculated the mean of each sample. The Central Limit Theorem asserts: [1] The mean of the sampling distribution of means is equal to the mean of the population from which the samples were drawn. [2] The variance of the sampling distribution of means is equal to the variance of the population from which the samples were drawn divided by the size of the samples. [3] If the original population is distributed normally, the sampling distribution of means will also be normal. If the original population is not normally distributed, the sampling distribution of means will increasingly approximate a normal distribution as sample size increases.

⁴ Moody's Investor Service: "2017 Outlook – Timely Cost-Recovery Drives Stable Outlook," November 4th, 2016.

1 To focus on OG&E's electric utility operations, companies with natural gas
2 operations were eliminated as well as companies below investment-grade. First
3 Energy and Great Plains Energy were eliminated on account of their ongoing
4 merger negotiations.

5 The final group of seventeen companies that comprises the OG&E proxy
6 group is shown on Direct Exhibit RAM-3. I stress that this proxy group must be
7 viewed as a portfolio of comparable risk. It would be inappropriate to select any
8 particular company or subset of companies from this group and infer the cost of
9 common equity from that company or subset alone.

10
11 **Q. What DCF results did you obtain for OG&E using Value Line growth**
12 **projections?**

13 A. Direct Exhibit RAM-4 displays the DCF analysis using Value Line growth
14 projections for the seventeen companies in OG&E's proxy group. Please note
15 that the growth forecasts for PPL Corp was drawn from the Zacks Investment
16 Research web site since the Value Line growth forecast was not available for that
17 company.

18 As shown on column 3, line 19 of Direct Exhibit RAM-4, the average
19 long-term earnings per share growth forecast obtained from Value Line is 5.65%
20 for OG&E's proxy group. Combining this growth rate with the average expected
21 dividend yield of 3.51% shown on column 4, line 19 of Direct Exhibit RAM-4
22 produces an estimate of equity costs of 9.15% for OG&E's proxy group, as shown
23 on column 5, line 19 of Direct Exhibit RAM-4. Recognition of flotation costs
24 brings the cost of equity estimate to 9.34% for the group, shown in Column 6.
25 The need for a flotation cost allowance is discussed at length later in my
26 testimony.

27
28 **Q. What DCF results did you obtain for OG&E using analysts' consensus**
29 **growth forecasts?**

30 A. Direct Exhibit RAM-5 displays the DCF analysis using analysts' consensus
31 growth forecasts for the seventeen companies in OG&E's proxy group. Please

1 note that the growth forecasts for Emera and Otter Tail were drawn from Value
2 Line since the Zacks growth forecast were not available for these two companies.

3 As shown on column 3, line 19 of Direct Exhibit RAM-5, the average
4 long-term earnings per share growth forecast obtained from analysts is 5.58% for
5 OG&E's proxy group. Combining this growth rate with the average expected
6 dividend yield of 3.50% shown on column 4, line 19, produces an estimate of
7 equity costs of 9.09% for OG&E's proxy group unadjusted for flotation cost, as
8 shown on column 5, line 19, of Direct Exhibit RAM-5. Recognition of flotation
9 costs brings the cost of equity estimate to 9.27%, shown in Column 6, line 19
10 which is nearly identical to the estimate from Value Line growth forecasts.

11
12 **Q. Please summarize the DCF estimates for OG&E.**

13 **A.** Table 1 below summarizes the DCF estimates for OG&E:
14

Table 1. DCF Estimates for OG&E

DCF STUDY	ROE
Electric Utilities Value Line Growth	9.3%
Electric Utilities Analysts Growth	9.3%

B. CAPM Estimates

15 **Q. Please describe your application of the CAPM risk premium approach.**

16 **A.** My first two risk premium estimates are based on the CAPM and on an empirical
17 approximation to the CAPM (ECAPM). The CAPM is a fundamental paradigm
18 of finance. Simply put, the fundamental idea underlying the CAPM is that risk-
19 averse investors demand higher returns for assuming additional risk, and higher-
20 risk securities are priced to yield higher expected returns than lower-risk
21 securities. The CAPM quantifies the additional return, or risk premium, required
22 for bearing incremental risk. It provides a formal risk-return relationship
23 anchored on the basic idea that only market risk matters, as measured by beta (β).
24 According to the CAPM, securities are priced such that:

1 EXPECTED RETURN = RISK-FREE RATE + RISK PREMIUM

2 Denoting the risk-free rate by R_F and the return on the market as a whole
3 by R_M , the CAPM is stated as follows:

4
$$K = R_F + \beta \times (R_M - R_F)$$

5 where: K = investors' expected return on equity

6 R_F = risk-free rate

7 R_M = return on the market as a whole

8 β = systematic risk (i.e., change in a security's return
9 relative to that of the market)

10 This is the seminal CAPM expression, which states that the return required
11 by investors is made up of a risk-free component, R_F , plus a risk premium
12 determined by $\beta \times (R_M - R_F)$. The bracketed expression $(R_M - R_F)$ expression is
13 known as the market risk premium (MRP). To derive the CAPM risk premium
14 estimate, three quantities are required: the risk-free rate (R_F), beta (β), and the
15 MRP, $(R_M - R_F)$.

16 For the risk-free rate (R_F), I used 4.4%, based on forecast interest rates on
17 long-term U.S. Treasury bonds.

18 For beta (β), I used 0.71 based on Value Line estimates.

19 For the MRP $((R_M - R_F))$, I used 7.0% based on historical market risk
20 premium studies.

21 These inputs to the CAPM are explained below.

22

23 **Q. How did you arrive at your risk-free rate estimate of 4.4% in your CAPM**
24 **analyses?**

25 **A.** To implement the CAPM and Risk Premium methods, an estimate of the risk-free
26 return is required as a benchmark. I relied on noted economic forecasts which call
27 for a rising trend in interest rates in response to the recovering economy, renewed
28 inflation, and record high federal deficits. Value Line, Global Insight, the
29 Congressional Budget Office, the U.S. Energy Information Administration, and

1 the U.S. Bureau of Labor Statistics among others all project higher long-term
2 Treasury bond rates in the future.

3
4 **Q. Why did you rely on long-term bonds instead of short-term bonds?**

5 A. The appropriate proxy for the risk-free rate in the CAPM is the return on the
6 longest-term Treasury bond possible. This is because common stocks are very
7 long-term instruments more akin to very long-term bonds rather than to short-
8 term Treasury bills or intermediate-term Treasury notes. In a risk premium
9 model, the ideal estimate for the risk-free rate has a term to maturity equal to the
10 security being analyzed. Since common stock is a very long-term investment
11 because the cash flows to investors in the form of dividends last indefinitely, the
12 yield on the longest-term possible government bonds, that is the yield on 30-year
13 Treasury bonds, is the best measure of the risk-free rate for use in the CAPM.
14 The expected common stock return is based on very long-term cash flows,
15 regardless of an individual's holding time period. Moreover, utility asset
16 investments generally have very long-term useful lives and should
17 correspondingly be matched with very long-term maturity financing instruments.

18 While long-term Treasury bonds are potentially subject to interest rate
19 risk, this is only true if the bonds are sold prior to maturity. A substantial fraction
20 of bond market participants, usually institutional investors with long-term
21 liabilities (e.g., pension funds and insurance companies), in fact hold bonds until
22 they mature, and therefore are not subject to interest rate risk. Moreover,
23 institutional bondholders neutralize the impact of interest rate changes by
24 matching the maturity of a bond portfolio with the investment planning period, or
25 by engaging in hedging transactions in the financial futures markets. The merits
26 and mechanics of such immunization strategies are well documented by both
27 academicians and practitioners

28 Another reason for utilizing the longest maturity Treasury bond possible is
29 that common equity has an infinite life span, and the inflation expectations
30 embodied in its market-required rate of return will therefore be equal to the
31 inflation rate anticipated to prevail over the very long term. The same expectation

1 should be embodied in the risk-free rate used in applying the CAPM model. It
2 stands to reason that the yields on 30-year Treasury bonds will more closely
3 incorporate within their yields the inflation expectations that influence the prices
4 of common stocks than do short-term Treasury bills or intermediate-term U.S.
5 Treasury notes.

6 Among U.S. Treasury securities, 30-year Treasury bonds have the longest
7 term to maturity and the yields on such securities should be used as proxies for
8 the risk-free rate in applying the CAPM. Therefore, I have relied on the yield on
9 30-year Treasury bonds in implementing the CAPM and risk premium methods.

10

11 **Q. Are there other reasons why you reject short-term interest rates as proxies**
12 **for the risk-free rate in implementing the CAPM?**

13 **A.** Yes. Short-term rates are volatile, fluctuate widely, and are subject to more
14 random disturbances than are long-term rates. Short-term rates are largely
15 administered rates. For example, Treasury bills are used by the Federal Reserve
16 as a policy vehicle to stimulate the economy and to control the money supply, and
17 are used by foreign governments, companies, and individuals as a temporary safe-
18 house for money.

19 As a practical matter, it makes no sense to match the return on common
20 stock to the yield on 90-day Treasury bills. This is because short-term rates, such
21 as the yield on 90-day Treasury bills, fluctuate widely, leading to volatile and
22 unreliable equity return estimates. Moreover, yields on 90-day Treasury bills
23 typically do not match the equity investor's planning horizon. Equity investors
24 generally have an investment horizon far in excess of 90 days.

25 As a conceptual matter, short-term Treasury bill yields reflect the impact
26 of factors different from those influencing the yields on long-term securities such
27 as common stock. For example, the premium for expected inflation embedded
28 into 90-day Treasury bills is likely to be far different than the inflationary
29 premium embedded into long-term securities yields. On grounds of stability and
30 consistency, the yields on long-term Treasury bonds match more closely with
31 common stock returns.

1

2 Q. **What is your estimate of the risk-free rate in applying the CAPM?**

3 A. All the noted interest rate forecasts that I am aware of point to significantly higher
4 interest rates over the next several years. Table 2 below reports the forecast
5 yields on 30-year US Treasury bonds from the Congressional Budget Office, U.S.
6 Department of Labor, U.S. Energy Information Administration, IHS (Global
7 Insight) and Value Line⁵.

8

9 Q. **Why did you ignore the current level of interest rates in developing your
10 proxy for the risk-free rate in a CAPM analysis?**

11 A. The CAPM is a forward-looking model based on expectations of the future. As a
12 result, in order to produce a meaningful estimate of investors' required rate of
13 return, the CAPM must be applied using data that reflects the expectations of
14 actual investors in the market. While investors examine history as a guide to the
15 future, it is the expectations of future events that influence security values and the
16 cost of capital.

**Table 2. Forecast Yields on
30-year U.S. Treasury Bonds**

	US 30-Yr Treas. L/T Yield Forecast
Congressional Budget Office	4.2
Bureau of Labor Statistics	4.8
U.S. Energy Information Administration	4.3
IHS (Global Insight)	4.6
Value Line Economic Forecast	4.5
Economic Report of the President	4.2
AVERAGE	4.4

17

⁵ When only forecasts of 10-year U.S. Treasury notes are available, 50 basis points were added to obtain the 30-year forecast, based on the historical spread between 30-year and 10-year U.S. Treasury bond yields.

1 Q. **How did you select the beta for your CAPM analysis?**

2 A. A major thrust of modern financial theory as embodied in the CAPM is that
3 perfectly diversified investors can eliminate the company-specific component of
4 risk, and that only market risk remains. The latter is technically known as “beta”
5 (β), or “systematic risk”. The beta coefficient measures change in a security’s
6 return relative to that of the market. The beta coefficient states the extent and
7 direction of movement in the rate of return on a stock relative to the movement in
8 the rate of return on the market as a whole. It indicates the change in the rate of
9 return on a stock associated with a one percentage point change in the rate of
10 return on the market, and thus measures the degree to which a particular stock
11 shares the risk of the market as a whole. Modern financial theory has established
12 that beta incorporates several economic characteristics of a corporation that are
13 reflected in investors’ return requirements.

14 OG&E is not publicly traded, and therefore, proxies must be used. In the
15 discussion of DCF estimates of the cost of common equity earlier, I examined a
16 sample of investment-grade dividend-paying vertically integrated electric utilities
17 covered by Value Line that have at least 50% of their revenues from regulated
18 electric utility operations. The average beta for this group is 0.71. Please see
19 Direct Exhibit RAM-6 for the beta estimates of the proxy group for OG&E. Based
20 on these results, I shall use 0.71, as an estimate for the beta applicable to OG&E.

21

22 Q. **What MRP did you use in your CAPM analysis?**

23 A. For the MRP, I used 7.0%. This estimate was based on the results of historical
24 studies of long-term market risk premiums and on two additional checks.

25

26 Q. **Can you describe the historical MRP study used in your CAPM analysis?**

27 A. Yes. The historical MRP estimate is based on the results obtained in Duff &
28 Phelps’ 2017 Valuation Handbook (formerly published by Morningstar and
29 earlier by Ibbotson Associates), which compiles historical returns from 1926 to
30 2016. This well-known study shows that a very broad market sample of common
31 stocks outperformed long-term U.S. Government bonds by 6.0%. The historical

1 MRP over the income component of long-term Government bonds rather than
2 over the total return is 7.0%. The historical MRP should be computed using the
3 income component of bond returns because the intent, even using historical data,
4 is to identify an expected MRP. The income component of total bond return (i.e.,
5 the coupon rate) is a far better estimate of expected return than the total return
6 (i.e., the coupon rate + capital gain), because both realized capital gains and
7 realized losses are largely unanticipated by bond investors. The long-horizon
8 (1926-2015) MRP (based on income returns, as required) is 7.0%.

9 As a first check on my 7.0% MRP estimate, I examined the historical
10 return on common stocks in real terms (inflation-adjusted) over the 1926-2016
11 period and added current inflation expectations to arrive at a current inflation-
12 adjusted common stock return. According to the Duff & Phelps study, the
13 average historical return on common stocks averaged 12.0% over the 1926-2016
14 period while inflation averaged 3.0% over the same period, implying a real return
15 of 9.0% ($12.0\% - 3.0\% = 9.0\%$). With current long-term inflation expectations of
16 2.0%⁶, the inflation-adjusted return on common stock becomes 11.0% ($9.0\% +$
17 $2.0\% = 11.0\%$). Given the current yield on 30-year U.S. Treasury bonds of
18 2.8%, the implied MRP is therefore 8.0% ($11.0\% - 2.8\% = 8.2\%$). Using the
19 forecast yield of 4.4%, the implied MRP is 6.6% ($11.0\% - 4.4\% = 6.6\%$). The
20 average of the two estimates is 7.4% which makes my 7.0% estimate
21 conservative.

22 As a second check on my MRP estimate, I examined Value Line's
23 projections. Each week, *Value Line* publishes the dividend yield for the 1700
24 stocks that it follows. It also estimates the 3-5 year appreciation potential of a
25 portfolio containing all of these stocks. As of September 2017, *Value Line* is
26 expecting an average annual appreciation for its universe of 1700 stocks of 7.8%.
27 Adding the average dividend yield of 2.1% on the 1700 stocks to the growth
28 estimate of 7.8% yields a total annual estimated return of 9.9%. Subtracting the

⁶ 30-year U.S. Treasury bonds are currently trading at a 2.8% yield while 30-year inflation-
adjusted bonds are trading at a yield of 0.8% implying a long-term inflation rate expectation of
2.0%.

1 current long-term (30-year) U.S. Treasury bond rate of 2.8% yields an expected
2 MRP of 7.1%% which is very close to my MRP estimate of 7.0%.

3
4 **Q. On what maturity bond does the Duff & Phelps historical risk premium data**
5 **rely?**

6 A. Because 30-year bonds were not always traded or even available throughout the
7 entire 1926-2016 period covered in the Duff & Phelps study of historical returns,
8 the latter study relied on bond return data based on 20-year Treasury bonds.
9 Given that the normal yield curve is virtually flat above maturities of 20 years
10 over most of the period covered in the Duff & Phelps study, the difference in
11 yield is not material.

12
13 **Q. Why did you use long time periods in arriving at your historical MRP**
14 **estimate?**

15 A. Because realized returns can be substantially different from prospective returns
16 anticipated by investors when measured over short time periods, it is important to
17 employ returns realized over long time periods rather than returns realized over
18 more recent time periods when estimating the MRP with historical returns.
19 Therefore, a risk premium study should consider the longest possible period for
20 which data are available. Short-run periods during which investors earned a
21 lower risk premium than they expected are offset by short-run periods during
22 which investors earned a higher risk premium than they expected. Only over long
23 time periods will investor return expectations and realizations converge.

24 I have therefore ignored realized risk premiums measured over short time
25 periods. Instead, I relied on results over periods of enough length to smooth out
26 short-term aberrations, and to encompass several business and interest rate cycles.
27 The use of the entire study period in estimating the appropriate MRP minimizes
28 subjective judgment and encompasses many diverse regimes of inflation, interest
29 rate cycles, and economic cycles.

30 To the extent that the estimated historical equity risk premium follows
31 what is known in statistics as a random walk, one should expect the equity risk

1 premium to remain at its historical mean. Since I found no evidence that the MRP
2 in common stocks has changed over time, at least prior to the onslaught of the
3 financial crisis of 2008-2009 which has now partially subsided, that is, no
4 significant serial correlation in the Duff & Phelps study prior to that time, it is
5 reasonable to assume that these quantities will remain stable in the future.
6

7 **Q. Should studies of historical risk premiums rely on arithmetic average returns**
8 **or geometric average returns?**

9 A. Whenever relying on historical risk premiums, only arithmetic average returns
10 over long periods are appropriate for forecasting and estimating the cost of
11 capital, and geometric average returns are not.⁷
12

13 **Q. Please explain how the issue of what is the proper “mean” arises in the**
14 **context of analyzing the cost of equity?**

15 A. The issue arises in applying methods that derive estimates of a utility’s cost of
16 equity from historical relationships between bond yields and earned returns on
17 equity for individual companies or portfolios of several companies. Those
18 methods produce series of numbers representing the annual difference between
19 bond yields and stock returns over long historical periods. The question is how to
20 translate those series into a single number that can be added to a current bond
21 yield to estimate the current cost of equity for a stock or a portfolio. Calculating
22 geometric and arithmetic means are two ways of converting series of numbers to a
23 single, representative figure.
24

25 **Q. If both are “representative” of the series, what is the difference between the**
26 **two means?**

27 A. Each mean represents different information about the series. The geometric mean

⁷ See Roger A. Morin, Regulatory Finance: Utilities’ Cost of Capital, Chapter 11 (1994); Roger A. Morin, The New Regulatory Finance: Utilities’ Cost of Capital, Chapter 4 (2006); Richard A. Brealey, et al., Principles of Corporate Finance (8th ed. 2006).

1 of a series of numbers is the value which, if compounded over the period
2 examined, would have made the starting value to grow to the ending value. The
3 arithmetic mean is simply the average of the numbers in the series. Where there
4 is any annual variation (volatility) in a series of numbers, the arithmetic mean of
5 the series, which reflects volatility, will always exceed the geometric mean, which
6 ignores volatility. Because investors require higher expected returns to invest in a
7 company whose earnings are volatile than one whose earnings are stable, the
8 geometric mean is not useful in estimating the expected rate of return which
9 investors require to make an investment.

10

11 **Q. Can you provide a numerical example to illustrate this difference between**
12 **geometric and arithmetic means?**

13 A. Yes. Table 3 below compares the geometric and arithmetic mean returns of a
14 hypothetical Stock A, whose yearly returns over a ten-year period are very
15 volatile, with those of a hypothetical Stock B, whose yearly returns are perfectly
16 stable during that period. Consistent with the point that geometric returns ignore
17 volatility, the geometric mean returns for the two series are identical (11.6% in
18 both cases), whereas the arithmetic mean return of the volatile stock (26.7%) is
19 much higher than the arithmetic mean return of the stable stock (11.6%).

20 If relying on geometric means, investors would require the same expected
21 return to invest in both of these stocks, even though the volatility of returns in
22 Stock A is very high while Stock B exhibits perfectly stable returns. That is
23 clearly contrary to the most basic financial theory, that is, the higher the risk the
24 higher the expected return.

25 Chapter 4 Appendix A of my book The New Regulatory Finance contains
26 a detailed and rigorous discussion of the impropriety of using geometric averages
27 in estimating the cost of capital. Briefly, the disparity between the arithmetic
28 average return and the geometric average return raises the question as to what
29 purposes should these different return measures be used. The answer is that the
30 geometric average return should be used for measuring historical returns that are
31 compounded over multiple time periods. The arithmetic average return should be

1 used for future-oriented analysis, where the use of expected values is appropriate.
2 It is inappropriate to average the arithmetic and geometric average return; they
3 measure different quantities in different ways.
4
5

Table 3. Arithmetic vs Geometric Mean Returns

<i>Year</i>	<i>Stock A</i>	<i>Stock B</i>
2007	50.0%	11.6%
2008	-54.7%	11.6%
2009	98.5%	11.6%
2010	42.2%	11.6%
2011	-32.3%	11.6%
2012	-39.2%	11.6%
2013	153.2%	11.6%
2014	-10.0%	11.6%
2015	38.9%	11.6%
2016	20.0%	11.6%
Std. Deviation	64.9%	0.0%
Arith Mean	26.7%	11.6%
Geom Mean	11.6%	11.6%

6

7 **Q. Is your MRP estimate of 7.0% consistent with the academic literature on the**
8 **subject?**

9 **A.** Yes, it is, although in the upper portion of the range. In their authoritative
10 corporate finance textbook, Professors Brealey, Myers, and Allen⁸ conclude from

⁸ Richard A. Brealey, Stewart C. Myers, and Paul Allen, Principles of Corporate Finance, 8th Edition, Irwin McGraw-Hill, 2006.

1 their review of the fertile literature on the MRP that a range of 5% to 8% is
2 reasonable for the MRP in the United States. My own survey of the MRP
3 literature, which appears in Chapter 5 of my latest textbook, The New Regulatory
4 Finance, is also quite consistent with this range.

5
6 **Q. What is your estimate of OG&E's cost of equity using the CAPM approach?**

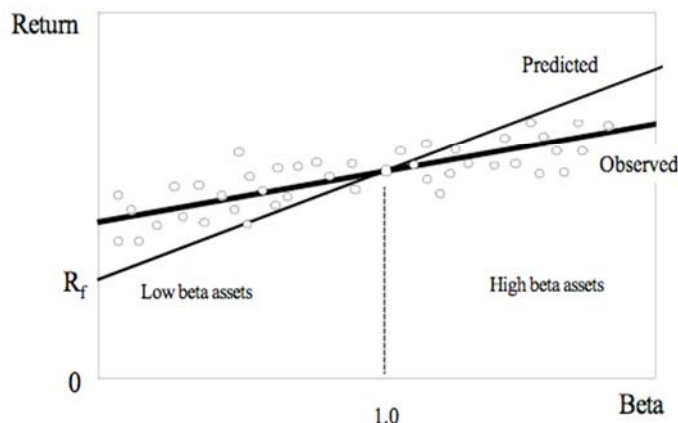
7 A. Inserting those input values into the CAPM equation, namely a risk-free rate of
8 4.4%, a beta of 0.71, and a MRP of 7.0%, the CAPM estimate of the cost of
9 common equity is: $4.4\% + 0.71 \times 7.0\% = 9.4\%$. This estimate becomes 9.6%
10 with flotation costs, discussed later in my testimony.

11
12 **Q. Can you describe your application of the empirical version of the CAPM?**

13 A. There have been countless empirical tests of the CAPM to determine to what
14 extent security returns and betas are related in the manner predicted by the
15 CAPM. This literature is summarized in Chapter 6 of my latest book, The New
16 Regulatory Finance. The results of the tests support the idea that beta is related to
17 security returns, that the risk-return tradeoff is positive, and that the relationship is
18 linear. The contradictory finding is that the risk-return tradeoff is not as steeply
19 sloped as the predicted CAPM. That is, empirical research has long shown that
20 low-beta securities earn returns somewhat higher than the CAPM would predict,
21 and high-beta securities earn less than predicted.

22 A CAPM-based estimate of cost of capital underestimates the return
23 required from low-beta securities and overstates the return required from high-
24 beta securities, based on the empirical evidence. This is one of the most well-
25 known results in finance, and it is displayed graphically below.

CAPM: Predicted vs Observed Returns



1 A number of variations on the original CAPM theory have been
 2 proposed to explain this finding. The ECAPM makes use of these empirical
 3 findings. The ECAPM estimates the cost of capital with the equation:

$$4 \quad K = R_F + \alpha + \beta \times (MRP - \alpha)$$

5 where the symbol alpha, α , represents the “constant” of the risk-return line,
 6 MRP is the market risk premium ($R_M - R_F$), and the other symbols are defined
 7 as usual.

8 Inserting the long-term risk-free rate as a proxy for the risk-free rate, an
 9 alpha in the range of 1% - 2%, and reasonable values of beta and the MRP in the
 10 above equation produces results that are indistinguishable from the following
 11 more tractable ECAPM expression:

$$12 \quad K = R_F + 0.25 (R_M - R_F) + 0.75 \beta (R_M - R_F)$$

13 An alpha range of 1% - 2% is somewhat lower than that estimated
 14 empirically. The use of a lower value for alpha leads to a lower estimate of the
 15 cost of capital for low-beta stocks such as regulated utilities. This is because
 16 the use of a long-term risk-free rate rather than a short-term risk-free rate already
 17 incorporates some of the desired effect of using the ECAPM. In other words,
 18 the long-term risk-free rate version of the CAPM has a higher intercept and a
 19 flatter slope than the short-term risk-free version which has been tested. This is

1 also because the use of adjusted betas rather than the use of raw betas also
2 incorporates some of the desired effect of using the ECAPM.⁹ Thus, it is
3 reasonable to apply a conservative alpha adjustment.

4 Please see Appendix A for a discussion of the ECAPM, including its
5 theoretical and empirical underpinnings.

6 In short, the following equation provides a viable approximation to the
7 observed relationship between risk and return, and provides the following cost of
8 equity capital estimate:

$$K = R_F + 0.25 (R_M - R_F) + 0.75 \times \beta \times (R_M - R_F)$$

9 Inserting the risk-free rate (R_F) of 4.4%, a MRP ($(R_M - R_F)$) of 7.0% for
10 $(R_M - R_F)$ and a beta of 0.71 in the above equation, the return on common equity
11 is 9.9%. This estimate becomes 10.1% with flotation costs, discussed later in my
12 testimony.

13

14 **Q. Is the use of the ECAPM consistent with the use of adjusted betas?**

15 **A.** Yes, it is. Some have argued that the use of the ECAPM is inconsistent with the
16 use of adjusted betas, such as those supplied by Value Line and Bloomberg. This
17 is because the reason for using the ECAPM is to allow for the tendency of betas to
18 regress toward the mean value of 1.00 over time, and, since Value Line betas are
19 already adjusted for such trend, an ECAPM analysis results in double-counting.
20 This argument is erroneous. Fundamentally, the ECAPM is not an adjustment,
21 increase or decrease in beta. The observed return on high beta securities is
22 actually lower than that produced by the CAPM estimate. The ECAPM is a

9 The regression tendency of betas to converge to 1.0 over time is very well known and widely discussed in the financial literature. As a result of this beta drift, several commercial beta producers adjust their forecasted betas toward 1.00 in an effort to improve their forecasts. Value Line, Bloomberg, and Merrill Lynch betas are adjusted for their long-term tendency to regress toward 1.0 by giving approximately 66% -weight to the measured raw beta and approximately 33% weight to the prior value of 1.0 for each stock:

$$\beta_{\text{adjusted}} = 0.33 + 0.66 \beta_{\text{raw}}$$

1 formal recognition that the observed risk-return tradeoff is flatter than predicted
2 by the CAPM based on myriad empirical evidence. The ECAPM and the use of
3 adjusted betas comprise two separate features of asset pricing. Even if a
4 company's beta is estimated accurately, the CAPM still understates the return for
5 low-beta stocks. Even if the ECAPM is used, the return for low-beta securities is
6 understated if the betas are understated. Referring back to the previous graph, the
7 ECAPM is a return (vertical axis) adjustment and not a beta (horizontal axis)
8 adjustment. Both adjustments are necessary. Moreover, the use of adjusted betas
9 compensates for interest rate sensitivity of utility stocks not captured by
10 unadjusted betas.

11

12 Q. **Please summarize your CAPM estimates.**

13 A. Table 4 below summarizes the common equity estimates obtained from the
14 CAPM studies.

Table 4. CAPM Results

<u>CAPM Method</u>	<u>ROE</u>
Traditional CAPM	9.6%
Empirical CAPM	10.1%

C. Historical Risk Premium Estimates

15 Q. **Please describe your historical risk premium analysis of the electric utility
16 industry using treasury bond yields.**

17 A. A historical risk premium for the utility industry was estimated with an annual
18 time series analysis applied to the utility industry as a whole over the 1930-2016
19 period, using Standard and Poor's Utility Index (S&P Utility Index) as an industry
20 proxy. The risk premium was estimated by computing the actual realized return
21 on equity capital for the S&P Utility Index for each year, using the actual stock
22 prices and dividends of the index, and then subtracting the long-term Treasury
23 bond return for that year. Please see Direct Exhibit RAM-7 for this analysis

24 As shown on Direct Exhibit RAM-7, the average risk premium over the
25 period was 5.5% over long-term Treasury bond yields and 6.1% over the income

1 component of bond yields. As discussed previously, the latter is the appropriate
2 risk premium to use. Given the risk-free rate of 4.4%, and using the historical
3 estimate of 6.1% for bond returns, the implied cost of equity is
4 $4.4\% + 6.1\% = 10.5\%$ without flotation costs and 10.7% with the flotation cost
5 allowance.

6
7 **Q. Are you concerned about the realism of the assumptions that underlie the**
8 **historical risk premium method?**

9 A. No, I am not, for they are no more restrictive than the assumptions that underlie
10 the DCF model or the CAPM. While it is true that the method looks backward in
11 time and assumes that the risk premium is constant over time, these assumptions
12 are not necessarily restrictive. By employing returns realized over long time
13 periods rather than returns realized over more recent time periods, investor return
14 expectations and realizations converge. Realized returns can be substantially
15 different from prospective returns anticipated by investors, especially when
16 measured over short time periods. By ensuring that the risk premium study
17 encompasses the longest possible period for which data are available, short-run
18 periods during which investors earned a lower risk premium than they expected
19 are offset by short-run periods during which investors earned a higher risk
20 premium than they expected. Only over long time periods will investor return
21 expectations and realizations converge, or else, investors would be reluctant to
22 invest money.

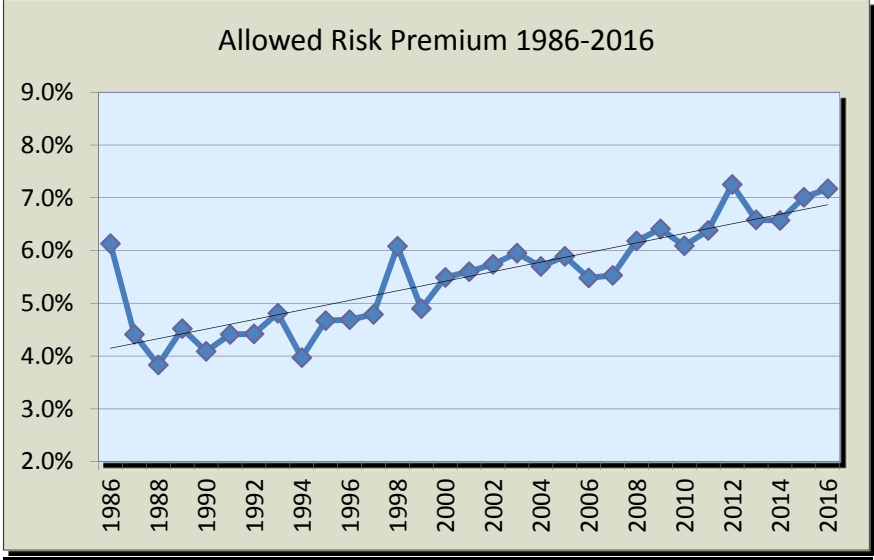
23
24 **D. Allowed Risk Premium Estimates**

25 **Q. Please describe your analysis of allowed risk premiums in the electric utility**
26 **industry.**

27 A. To estimate the electric utility industry's cost of common equity, I also examined
28 the historical risk premiums implied in the ROEs allowed by regulatory
29 commissions for electric utilities over the 1986-2016 period for which data were
30 available, relative to the contemporaneous level of the long-term Treasury bond
31 yield. Please see Direct Exhibit RAM-8 for this analysis.

1 This variation of the risk premium approach is reasonable because
 2 allowed risk premiums are presumably based on the results of market-based
 3 methodologies (DCF, CAPM, Risk Premium, *etc.*) presented to regulators in rate
 4 hearings and on the actions of objective unbiased investors in a competitive
 5 marketplace. Historical allowed ROE data are readily available over long periods
 6 on a quarterly basis from Regulatory Research Associates (now S&P Global
 7 Intelligence) and easily verifiable from prior issues of that same publication and
 8 past commission decision archives.

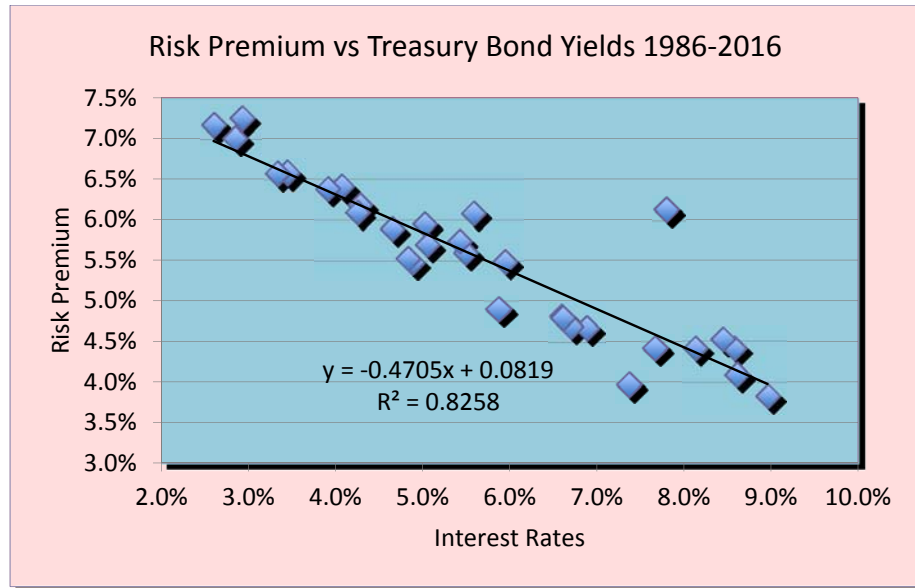
9 The average ROE spread over long-term Treasury yields was 5.51% over
 10 the entire 1986-2016 period for which data were available from SNL. The graph
 11 below shows the year-by-year allowed risk premium. The escalating trend of the
 12 risk premium in response to lower interest rates and rising competition is
 13 noteworthy.



14 A careful review of these ROE decisions relative to interest rate
 15 trends reveals a narrowing of the risk premium in times of rising interest
 16 rates, and a widening of the premium as interest rates fall. The following
 17 statistical relationship between the risk premium (RP) and interest rates
 18 (YIELD) emerges over the 1986-2016 period:

19
$$RP = 8.1900 - 0.4705 \text{ YIELD} \qquad R^2 = 0.83$$

1 The relationship is highly statistically significant¹⁰ as indicated by the very
2 high R². The graph below shows a clear inverse relationship between the
3 allowed risk premium and interest rates as revealed in past ROE decisions.



4 Inserting the long-term Treasury bond yield of 4.40% in the above
5 equation suggests a risk premium estimate of 6.12%, implying a cost of
6 equity of 10.52%. The latter result is reasonably close to the result of the
7 historical risk premium study.

8

9 **Q. Do investors take into account allowed returns in formulating their**
10 **return expectations?**

11 **A.** Yes, they do. Investors do indeed take into account returns granted by various
12 regulators in formulating their risk and return expectations, as evidenced by the
13 availability of commercial publications disseminating such data, including Value
14 Line and SNL (formerly Regulatory Research Associates). Allowed returns,
15 while certainly not a precise indication of a particular company's cost of equity

¹⁰ The coefficient of determination R², sometimes called the "goodness of fit measure," is a measure of the degree of explanatory power of a statistical relationship. It is simply the ratio of the explained portion to the total sum of squares. The higher R² the higher is the degree of the overall fit of the estimated regression equation to the sample data.

1 capital, are nevertheless important determinants of investor growth perceptions
2 and investor expected returns.

3

4 Q. **Please summarize your risk premium estimates.**

5 A. Table 5 below summarizes the ROE estimates obtained from the two risk
6 premium studies.

7

Table 5. Risk Premium Estimates

Risk Premium Method	ROE
Historical Risk Premium Electric	10.7%
Allowed Risk Premium	10.5%

E. Need for Flotation Cost Adjustment

8 Q. **Please describe the need for a flotation cost allowance.**

9 A. All the market-based estimates reported above include an adjustment for flotation
10 costs. The simple fact of the matter is that issuing common equity capital is not
11 free. Flotation costs associated with stock issues are similar to the flotation costs
12 associated with bonds and preferred stocks. Flotation costs are not expensed at
13 the time of issue, and therefore must be recovered via a rate of return adjustment.
14 This is done routinely for bond and preferred stock issues by most regulatory
15 commissions, including FERC. Clearly, the common equity capital accumulated
16 by the Company is not cost-free. The flotation cost allowance to the cost of
17 common equity capital is discussed and applied in most corporate finance
18 textbooks; it is unreasonable to ignore the need for such an adjustment.

19 Flotation costs are very similar to the closing costs on a home mortgage.
20 In the case of issues of new equity, flotation costs represent the discounts that
21 must be provided to place the new securities. Flotation costs have a direct and an
22 indirect component. The direct component is the compensation to the security
23 underwriter for his marketing/consulting services, for the risks involved in
24 distributing the issue, and for any operating expenses associated with the issue

1 (e.g., printing, legal, prospectus). The indirect component represents the
2 downward pressure on the stock price as a result of the increased supply of stock
3 from the new issue. The latter component is frequently referred to as “market
4 pressure.”

5 Investors must be compensated for flotation costs on an ongoing basis to
6 the extent that such costs have not been expensed in the past, and therefore the
7 adjustment must continue for the entire time that these initial funds are retained in
8 the firm. Appendix B to my testimony discusses flotation costs in detail, and
9 shows: (1) why it is necessary to apply an allowance of 5% to the dividend yield
10 component of equity cost by dividing that yield by 0.95 (100% - 5%) to obtain the
11 fair return on equity capital; (2) why the flotation adjustment is permanently
12 required to avoid confiscation even if no further stock issues are contemplated;
13 and (3) that flotation costs are only recovered if the rate of return is applied to
14 total equity, including retained earnings, in all future years.

15 By analogy, in the case of a bond issue, flotation costs are not expensed
16 but are amortized over the life of the bond, and the annual amortization charge is
17 embedded in the cost of service. The flotation adjustment is also analogous to the
18 process of depreciation, which allows the recovery of funds invested in utility
19 plant. The recovery of bond flotation expense continues year after year,
20 irrespective of whether the Company issues new debt capital in the future, until
21 recovery is complete, in the same way that the recovery of past investments in
22 plant and equipment through depreciation allowances continues in the future even
23 if no new construction is contemplated. In the case of common stock that has no
24 finite life, flotation costs are not amortized. Thus, the recovery of flotation costs
25 requires an upward adjustment to the allowed return on equity.

26 A simple example will illustrate the concept. A stock is sold for \$100, and
27 investors require a 10% return, that is, \$10 of earnings. But if flotation costs are
28 5%, the Company nets \$95 from the issue, and its common equity account is
29 credited by \$95. In order to generate the same \$10 of earnings to the
30 shareholders, from a reduced equity base, it is clear that a return in excess of 10%
31 must be allowed on this reduced equity base, here 10.53%.

1 According to the empirical finance literature discussed in Appendix B,
2 total flotation costs amount to 4% for the direct component and 1% for the market
3 pressure component, for a total of 5% of gross proceeds. This in turn amounts to
4 approximately 20 basis points, depending on the magnitude of the dividend yield
5 component. To illustrate, dividing the average expected dividend yield of around
6 4.0% for utility stocks by 0.95 yields 4.2%, which is 20 basis points higher.

7 Sometimes, the argument is made that flotation costs are real and should
8 be recognized in calculating the fair return on equity, but only at the time when
9 the expenses are incurred. In other words, as the argument goes, the flotation cost
10 allowance should not continue indefinitely, but should be made in the year in
11 which the sale of securities occurs, with no need for continuing compensation in
12 future years. This argument is valid only if the Company has already been
13 compensated for these costs. If not, the argument is without merit. My own
14 recommendation is that investors be compensated for flotation costs on an on-
15 going basis rather than through expensing, and that the flotation cost adjustment
16 continue for the entire time that these initial funds are retained in the firm.

17 In theory, flotation costs could be expensed and recovered through rates as
18 they are incurred. This procedure, although simple in implementation, is not
19 considered appropriate, however, because the equity capital raised in a given stock
20 issue remains on the utility's common equity account and continues to provide
21 benefits to ratepayers indefinitely. It would be unfair to burden the current
22 generation of ratepayers with the full costs of raising capital when the benefits of
23 that capital extend indefinitely. The common practice of capitalizing rather than
24 expensing eliminates the intergenerational transfers that would prevail if today's
25 ratepayers were asked to bear the full burden of flotation costs of bond/stock issues
26 in order to finance capital projects designed to serve future as well as current
27 generations. Moreover, expensing flotation costs requires an estimate of the market
28 pressure effect for each individual issue, which is likely to prove unreliable. A more
29 reliable approach is to estimate market pressure for a large sample of stock offerings
30 rather than for one individual issue.

1 There are several sources of equity capital available to a firm including:
2 common equity issues, conversions of convertible preferred stock, dividend
3 reinvestment plans, employees' savings plans, warrants, and stock dividend
4 programs. Each carries its own set of administrative costs and flotation cost
5 components, including discounts, commissions, corporate expenses, offering
6 spread, and market pressure. The flotation cost allowance is a composite factor
7 that reflects the historical mix of sources of equity. The allowance factor is a
8 build-up of historical flotation cost adjustments associated with and traceable to
9 each component of equity at its source. It is impractical and prohibitively costly
10 to start from the inception of a company and determine the source of all present
11 equity. A practical solution is to identify general categories and assign one factor
12 to each category. My recommended flotation cost allowance is a weighted
13 average cost factor designed to capture the average cost of various equity vintages
14 and types of equity capital raised by the Company.

15
16 **Q. Dr. Morin, can you please elaborate on the market pressure component of**
17 **flotation cost?**

18 **A.** The indirect component, or market pressure component of flotation costs
19 represents the downward pressure on the stock price as a result of the increased
20 supply of stock from the new issue, reflecting the basic economic fact that when
21 the supply of securities is increased following a stock or bond issue, the price
22 falls. The market pressure effect is real, tangible, measurable, and negative.
23 According to the empirical finance literature cited in Appendix B, the market
24 pressure component of the flotation cost adjustment is approximately 1% of the
25 gross proceeds of an issuance. The announcement of the sale of large blocks of
26 stock produces a decline in a company's stock price, as one would expect given
27 the increased supply of common stock.

28
29 **Q. Is a flotation cost adjustment required for an operating subsidiary like**
30 **OG&E that does not trade publicly?**

1 A. Yes, it is. It is sometimes alleged that a flotation cost allowance is inappropriate
2 if the utility is a subsidiary whose equity capital is obtained from its owners, in
3 this case, OG&E. This objection is unfounded since the parent-subsidiary
4 relationship does not eliminate the costs of a new issue, but merely transfers them
5 to the parent. It would be unfair and discriminatory to subject parent shareholders
6 to dilution while individual shareholders are absolved from such dilution. Fair
7 treatment must consider that, if the utility-subsidiary had gone to the capital
8 markets directly, flotation costs would have been incurred.
9

10 IV. ROE RECOMMENDATION

11 Q. **Please summarize your results and recommendation.**

12 A. To arrive at my final recommendation, I performed

- 13 (i) a DCF analysis on a group of investment-grade dividend-paying
14 vertically integrated electric utilities using Value Line's growth
15 forecasts;
- 16 (ii) a DCF analysis on a group of investment-grade dividend-paying
17 vertically integrated electric utilities using analysts' growth
18 forecasts;
- 19 (iii) a traditional CAPM using current market data;
- 20 (iv) an empirical approximation of the CAPM using current market data;
- 21 (v) historical risk premium data from electric utility industry aggregate
22 data, using the yield on long-term US Treasury bonds; and
23
- 24 (vi) allowed risk premium data from electric utility industry aggregate
25 data, using the current yield on long-term US Treasury bonds.

1
2

Table 6 below summarizes the ROE estimates for OG&E.

Table 6. Summary of ROE Estimates

STUDY	ROE
Integrated Utilities Value Line Growth	9.3%
Integrated Utilities Analysts Growth	9.3%
CAPM	9.6%
Empirical CAPM	10.1%
Historical Risk Premium Electric	10.7%
Allowed Risk Premium	10.5%

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The average estimate is 9.9% as well as the median and truncated mean. The results range from 9.3% to 10.7%, with a midpoint of 10.0%. Based on all those results, I use the average result of 9.9% as my recommended ROE for OG&E.

I stress that no one individual method provides an exclusive foolproof formula for determining a fair return, but each method provides useful evidence so as to facilitate the exercise of an informed judgment. Reliance on any single method or preset formula is hazardous when dealing with investor expectations. Moreover, the advantage of using several different approaches is that the results of each one can be used to check the others. Thus, the results shown in Table 6 above must be viewed as a whole rather than each as a stand-alone. It would be inappropriate to select any particular number from Table 6 and infer the cost of common equity from that number alone.

16 **Q. Dr. Morin, what is your final conclusion regarding OG&'s return on**
17 **common equity capital?**

18 **A.** Based on the results of all my analyses, the application of my professional
19 judgment, and the risk circumstances of OG&E, it is my opinion that a just and
20 reasonable ROE for OG&E's electric utility operations in the State Oklahoma is
21 9.9%.

22

1 **V. CAPITAL STRUCTURE**

2 **Q. Dr. Morin, what capital structure assumption underlies your recommended**
3 **return on OG&E's common equity capital?**

4 A. My recommended return on common equity for OG&E is predicated on the
5 adoption of a test year capital structure consisting of approximately 53% common
6 equity capital, which is the Company's actual capital structure.

7
8 **Q. Is the Company's actual capital structure reasonable for ratemaking**
9 **purposes?**

10 A. Yes, it is for several reasons. First, I have examined the actual capital structures
11 of the operating utility companies in my comparable group of electric utilities.
12 Direct Exhibit RAM- 9 displays the common equity ratios for the operating
13 electric utilities in my peer group of companies as reported in SNL Financial in
14 2017. The average common equity ratio reported for 2017 is 53%, the same as
15 the Company's.

16 Second, I have examined the credit agencies' financial ratio benchmarks
17 for various bond rating categories for utilities. Both S&P and Moody's publish a
18 matrix of financial ratios that correspond to their respective assessment of the
19 investment risk of utility companies and related bond rating.

20 Table 7 below reproduces Moody's range for a utility company's debt
21 ratio and related bond rating, one of its four primary financial ratios that it uses as
22 guidance in its credit review for utility companies¹¹. For a single A bond rating,
23 which is OG&E's bond rating, and which I consider optimal and cost efficient for
24 ratepayers, the debt ratio range is 35%-45%, implying a common equity ratio
25 range of 55% - 65%. Even for a Baa bond rating, the corresponding debt ratio
26 range is 45% - 55%, implying a common equity range of 45% - 55%, consistent
27 with OG&E's 53% ratio.

28

¹¹ Moody's Investors Service, "Electric & Gas Utilities: Assessing Their Credit Quality and Outlook", Jan. 2013.

Table 7 Moody's Debt Ratio Benchmark

Bond Rating	Debt/capital %
Aaa	<25
Aa	25-35
A	35-45
Baa	45-55
Ba	55-65
B	>65

1

2

S&P also publishes ranges for three primary financial ratios that it uses as guidance in its credit review for utility companies. One of the three core financial ratio benchmarks on which it relies in its credit rating process is the debt ratio. Direct Exhibit RAM-10 replicates S&P's risk matrix criteria which includes business and financial risk categories.^{12/} As shown on the upper panel of the exhibit, the business risk profile categories are "Excellent," "Strong," "Satisfactory," "Fair," "Weak," and "Vulnerable." Most utilities have a business risk profile of "Excellent" or "Strong."

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As shown on the middle panel, the financial risk profile categories are "Minimal," "Modest," "Intermediate," "Significant," "Aggressive," and "Highly Leveraged." Most utilities have a "Intermediate" or "Significant" financial risk profile coupled with a business risk profile of "Excellent" or "Strong", and are therefore rated in the A-BBB range, as shown in the darkened cell entries.

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The third panel of the exhibit shows S&P's range for a utility company's debt ratio. For those utilities with "Intermediate" financial risk, the debt ratio range is 35%-45% with a midpoint of 40%, implying a common equity ratio of 60%, the same result as S&P. For those utilities with "Significant" financial risk, the corresponding debt ratio range is 45% - 55% with a midpoint of 50%, or a 50% common equity ratio, again the same result as Moody's.

^{12/} S&P updated its 2008 credit metric guidelines in 2009, and incorporated utility metric benchmarks with the general corporate rating metrics. *Standard & Poor's RatingsDirect*: "Criteria Methodology: Business Risk/Financial Risk Matrix Expanded," May 27, 2009.

1 It is clear from these multiple perspectives that OG&E's 53% common
2 equity ratio is appropriate. I show below why it is essential for both the Company
3 and its ratepayers to retain the Company's single A bond rating which is
4 predicated in part on its robust balance sheet. The Commission's regulatory
5 support is required in order to maintain a financially healthy OG&E, including
6 retaining its existing bond rating which I show to be optimal below. Given that
7 ROE exerts a direct impact on the determinants of a credit rating, approval of my
8 recommended ROE certainly increases the probability that OG&E will retain its
9 single A bond rating which is cost efficient for ratepayers as discussed below.

10
11 **Q. What would be the consequences of imputing a capital structure different**
12 **from the company's actual capital structure and consisting of more debt?**

13 A. The first consequence is that the Commission would endanger the retention of the
14 Company's single A bond rating and increase the probability of a downgrade. A
15 higher cost of capital is likely to follow suit as I show below. Secondly, if the
16 Commission imputes a capital structure consisting of more debt than the
17 Company's test year capital structure, the higher common equity cost rate related
18 to a changed common equity ratio should be reflected in the approach. It is a
19 fundamental tenet of finance that the greater the amount of financial risk borne by
20 common shareholders, the greater the return required by shareholders in order to
21 be compensated for the added financial risk imparted by the greater use of senior
22 debt financing. In other words, the greater the debt ratio, the greater is the return
23 required by equity investors. The cost of equity must be adjusted to reflect the
24 additional risk associated with the more debt-heavy capital structure.

25 Several researchers have studied the empirical relationship between the
26 cost of capital, capital-structure changes, and the value of the firm's securities.¹³
27 The empirical studies suggest an average increase of 76 basis points, or 7.6 basis
28 points per one percentage point increase in the debt ratio. The theoretical studies

¹³ See Roger A. Morin, *The New Regulatory Finance* (2006) Chapter 16 section 16-4 for a summary of the literature on the relationship between cost of capital and leverage for public utilities.

1 suggest an average increase of 138 basis points, or 13.8 basis points per one
2 percentage point increase in the debt ratio. In other words, equity return
3 requirements increase between 7.6 and 13.8 basis points with a midpoint of
4 approximately 10 basis points for each one percentage point increase in the debt
5 ratio, and more recent studies indicate that the upper end of that range is more
6 indicative of the repercussions on required equity returns.

7 As discussed above, for every 1% downward change in the common
8 equity ratio, the required ROE adjustment increases by 10 basis points. For
9 example, taking the 10 basis points benchmark, to go from 50% to 45% common
10 equity, the increase in ROE would be 50 basis points, that is, $(50-45) = 5$, and $5 \times$
11 $10 = 50$ basis points. The simple fact of the matter is that lower common equity
12 ratios imply greater risk and higher capital cost.

14 VI. OPTIMAL BOND RATING AND CAPITAL STRUCTURE

15 Q. **Dr. Morin, what is the optimal bond rating for a regulated electric utility?**

16 A. A single A bond rating generally results in the lowest pre-tax cost of capital for
17 electric utilities, and therefore the lowest ratepayer burden, especially under adverse
18 economic conditions, which are far more relevant to the question of capital structure.
19 This result prevails over a wide range of cost of common equity models and
20 estimates utilized, and remains robust to changes in key assumptions.

21 As I showed in the optimal capital structure simulation model developed in
22 Chapter 19 of my book The New Regulatory Finance, a strong single A bond rating
23 will minimize the pre-tax cost of capital to ratepayers. Long-term
24 achievement/retention of a single A bond rating is in both the electric utility
25 company's and ratepayers' best interests. If the company maintains its debt ratio
26 within the optimal range discussed earlier for an A-rated company, its overall cost of
27 capital should be minimized. If the company reduces its debt ratio below that point,
28 it would be giving up the tax benefits associated with debt but would not reap the
29 benefits from a lower cost of debt and equity. If the company operates at a debt ratio
30 beyond that point, the cost of debt and equity will rise, and therefore so will the cost
31 of service.

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Q. Dr. Morin, can you provide a simple numerical example showing what would happen to ratepayers if the company's bonds were downgraded from single A to BBB.

A. The following example shows that the ratepayer burden would increase significantly. Let's say the Company issues a 20-year \$100 million bond. The difference in cost between being a single A-rated company and being a BBB-rated company is approximately 50 basis points (0.50%) based on historical spreads between A and BBB bonds, that is, the cost of debt increases by 50 basis points. So, every year for 20 years, the additional cost to ratepayers is \$500,000 (0.50% times \$100). Over the entire 20-year period the total additional cost to ratepayers is therefore \$10 million (20 times \$500,000). This example is conservative, for it does not even consider the increase in common equity capital costs.

In short, for every \$100 million of bonds issued by the company, the cost to ratepayers of being a BBB company instead of being a single A company is \$10 million. Further, upon a downgrade the holders of the Company's outstanding debt could sustain a considerable loss. Since this nearly \$3 billion of debt must eventually be refinanced, the ultimate impact to ratepayers could be substantial before even considering the increased equity costs.

Q. Besides the increase costs to ratepayers, are there other consequences if the Company's bonds were downgraded?

A. Yes, there are. Besides the aforementioned substantial increase in ratepayer burden, existing bondholders would incur a capital loss with the attendant rise in the cost of debt, and the cost of common equity capital would rise as well. Thus, it is imperative that the Commission remains supportive in order to maintain the Company's single A rating and avoid the aforementioned consequences. Approval of my recommended ROE would certainly substantially increase the probability of maintaining the Company's financial integrity and its existing optimal bond rating.

1 Q. **Do you have any concerns regarding the regulatory climate in Oklahoma at**
2 **this time?**

3 A. Yes, I do. I am concerned with recent statements published by members of the
4 investment community with regards with Oklahoma regulation.

5 In its recent state regulatory evaluations, Regulatory Research Associates
6 (“RRA”), an offering of S&P Global Intelligence, downgraded its ranking of the
7 OCC from Average/2 to Average/3 presumably on account of the negative aspects
8 of the Commission’s last rate order¹⁴.

9 In its recent credit rating report, Fitch labeled Oklahoma regulation as
10 “deteriorating”, and explicitly stated¹⁵:

11 *“In Fitch’s view, OCC’s regulation has been reasonably supportive*
12 *overall, but is showing signs of deterioration.”*

13 Fitch expressed its concern with the Commission’s lengthy review of
14 OG&E’s environmental compliance plan, with the Company’s last general rate
15 case, and with its unfavorable rate order.

16 On June 27th, 2017, Moody’s Investor Service downgraded the Company’s
17 credit rating outlook to “Negative”. More specifically, Moody’s stated¹⁶:

18 *"The negative outlook reflects the potential for a decline in financial*
19 *metrics amidst some uncertainty over cost recovery and earned returns in*
20 *Oklahoma" said Ryan Wobbrock, Vice President -- Senior Analyst.*
21 *"OG&E's cash flow to debt could persist at around 25%, which is weak*
22 *for the company's current A1 rating" added Wobbrock. OG&E's financial*
23 *deterioration will have a similar negative impact on parent OGE's*
24 *metrics, since the utility makes up over 80% of OGE's consolidated cash*
25 *flow. **The expected financial pressure is due to a March rate order that***
26 ***reduced certain depreciation recovery levels and OG&E's allowed return***
27 ***on equity (ROE) in Oklahoma.** This will result in lower cash flow levels*

¹⁴ Regulatory Research Associates: “State Regulatory Evaluations, Regulatory Climate for Energy Utilities.” May 11, 2017.

¹⁵ Fitch Ratings: Oklahoma Gas & Electric, July 14, 2017

¹⁶ Moody’s Investor Service: “Rating Action” Moody’s Changes OGE and OG&E Outlooks to Negative.” June 29, 2017.

1 *than previously anticipated, as OG&E seeks recovery for over \$1 billion*
2 *in capex over the next two years. These rate cases will increase revenue*
3 *and cash flow, but comments made by the Oklahoma Corporation*
4 *Commission (OCC) in the March order could foreshadow a lower equity*
5 *layer used for these rates as well, a credit negative. Less equity, extended*
6 *depreciation recovery and a lower ROE would likely keep cash flow to*
7 *debt below the 28% level that OG&E has historically produced.”*

8
9 On May 19, 2017, Moody’s further stated¹⁷:

10
11 *“Regulatory actions in some states have challenged cost recovery*
12 *provisions and earned returns, a credit negative for utilities. a recent*
13 *rate case decision for Oklahoma Gas & Electric Corporation (OG&E, A1*
14 *stable) reduced the company's allowed return on equity level and lowered*
15 *the depreciation expense allowed to be recovered in rates.”*

16
17 I am confident that the OCC will assuage, if not reverse, these concerns by
18 a credit supportive decision in this case which includes authorizing a ROE equal
19 to my recommendation. I reiterate the importance through supportive regulation
20 of retaining the Company’s single A bond rating which I consider cost efficient
21 for both ratepayers and investors.

22
23 **Q. Were Direct Exhibits RAM-1 through RAM-10 and Appendices A and B**
24 **prepared by you and/or under your direction and control?**

25 A. Yes, they were.

26
27 **Q. Does this conclude your pre-filed direct testimony?**

28 A. Yes.

¹⁷ Moody’s Investor Service: “Change is Afoot in Utility Regulation, But Credit Impact Varies,” 5/ 2017.

RESUME OF ROGER A. MORIN

(Winter 2017)

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Indian Harbour
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(902) 823-0000 summer office

E-MAIL ADDRESS: profmorin@mac.com

EMPLOYER 1980-2015: Georgia State University
Robinson College of Business
Atlanta, GA 30303

RANK: Emeritus Professor of Finance

HONORS: Distinguished Professor of Finance for Regulated Industry,
Director Center for the Study of Regulated Industry,
Robinson College of Business, Georgia State University.

EDUCATIONAL HISTORY

- Bachelor of Electrical Engineering, McGill University, Montreal, Canada, 1967.
- Master of Business Administration, McGill University, Montreal, Canada, 1969.
- PhD in Finance & Econometrics, Wharton School of Finance, University of Pennsylvania, 1976.

EMPLOYMENT HISTORY

- Lecturer, Wharton School of Finance, Univ. of Pennsylvania, 1972-3
- Assistant Professor, University of Montreal School of Business, 1973-1976.
- Associate Professor, University of Montreal School of Business, 1976-1979.
- Professor of Finance, Georgia State University, 1979-2011
- Professor of Finance for Regulated Industry and Director,

Center for the Study of Regulated Industry, Robinson College of Business, Georgia State University, 1985-2009

- Visiting Professor of Finance, Amos Tuck School of Business, Dartmouth College, Hanover, N.H., 1986
- Emeritus Professor of Finance, Georgia State University, 2007-16

OTHER BUSINESS ASSOCIATIONS

- Communications Engineer, Bell Canada, 1962-1967.
- Member Board of Directors, Financial Research Institute of Canada, 1974-1980.
- Co-founder and Director Canadian Finance Research Foundation, 1977.
- Vice-President of Research, Garmaise-Thomson & Associates, Investment Management Consultants, 1980-1981.
- Member Board of Directors, Executive Visions Inc., 1985-2016
- Board of External Advisors, College of Business, Georgia State University, Member 1987-1991.
- Member Board of Directors, Hotel Equities Inc., 2009-2016

PROFESSIONAL CLIENTS

AGL Resources
AT & T Communications
Alagasco - Energen
Alaska Anchorage Municipal Light & Power
Alberta Power Ltd.
Allete
Alliant Energy
AmerenUE
American Water
Ameritech
Arkansas Western Gas
ATC Transmission
Baltimore Gas & Electric – Constellation Energy
Bangor Hydro-Electric
B.C. Telephone
B C GAS
Bell Canada
Bellcore
Bell South Corp.
Bruncor (New Brunswick Telephone)

Burlington-Northern
C & S Bank
California Pacific
Cajun Electric
Canadian Radio-Television & Telecomm. Commission
Canadian Utilities
Canadian Western Natural Gas
Cascade Natural Gas
Centel
Centra Gas
Central Illinois Light & Power Co
Central Telephone
Central & South West Corp.
CH Energy
Chattanooga Gas Company
Cincinnati Gas & Electric
Cinergy Corp.
Citizens Utilities
City Gas of Florida
CN-CP Telecommunications
Commonwealth Telephone Co.
Columbia Gas System
Consolidated Edison
Consolidated Natural Gas
Constellation Energy
Delmarva Power & Light Co
Deerpath Group
Detroit Edison Company
Dayton Power & Light Co.
DPL Energy
Duke Energy Indiana
Duke Energy Kentucky
Duke Energy Ohio
DTE Energy
Edison International
Edmonton Power Company
Elizabethtown Gas Co.
Emera
Energen
Engraph Corporation
Entergy Corp.
Entergy Arkansas Inc.
Entergy Gulf States, Inc.
Entergy Louisiana, Inc.
Entergy Mississippi Power
Entergy New Orleans, Inc.

First Energy
Florida Water Association
Fortis
Garmaise-Thomson & Assoc., Investment Consultants
Gaz Metropolitain
General Public Utilities
Georgia Broadcasting Corp.
Georgia Power Company
GTE California - Verizon
GTE Northwest Inc. - Verizon
GTE Service Corp. - Verizon
GTE Southwest Incorporated - Verizon
Gulf Power Company
Havasu Water Inc.
Hawaiian Electric Company
Hawaiian Elec & Light Co
Heater Utilities – Aqua - America
Hope Gas Inc.
Hydro-Quebec
ICG Utilities
Illinois Commerce Commission
Island Telephone
ITC Holdings
Jersey Central Power & Light
Kansas Power & Light
KeySpan Energy
Maine Public Service
Manitoba Hydro
Maritime Telephone
Maui Electric Co.
Metropolitan Edison Co.
Minister of Natural Resources Province of Quebec
Minnesota Power & Light
Mississippi Power Company
Missouri Gas Energy
Mountain Bell
National Grid PLC
Nevada Power Company
New Brunswick Power
Newfoundland Power Inc. - Fortis Inc.
New Market Hydro
New Tel Enterprises Ltd.
New York Telephone Co.
NextEra Energy
Niagara Mohawk Power Corp
Norfolk-Southern

Northeast Utilities
Northern Telephone Ltd.
Northwestern Bell
Northwestern Utilities Ltd.
Nova Scotia Power
Nova Scotia Utility and Review Board
NUI Corp.
NV Energy
NYNEX
Oklahoma G & E
Ontario Telephone Service Commission
Orange & Rockland
PNM Resources
PPL Corp
Pacific Northwest Bell
People's Gas System Inc.
People's Natural Gas
Pennsylvania Electric Co.
Pepco Holdings
Potomac Electric Power Co.
Price Waterhouse
PSI Energy
Public Service Electric & Gas
Public Service of New Hampshire
Public Service of New Mexico
Puget Sound Energy
Quebec Telephone
Regie de l'Energie du Quebec
Rockland Electric
Rochester Telephone
SNL Center for Financial Execution
San Diego Gas & Electric
SaskPower
Sempra
Sierra Pacific Power Company
Source Gas
Southern Bell
Southern States Utilities
Southern Union Gas
South Central Bell
Sun City Water Company
TECO Energy
The Southern Company
Touche Ross and Company
TransEnergie
Trans-Quebec & Maritimes Pipeline

TXU Corp
 US WEST Communications
 Union Heat Light & Power
 Utah Power & Light
 Vermont Gas Systems Inc.
 Wisconsin Power & Light

MANAGEMENT DEVELOPMENT AND PROFESSIONAL EXECUTIVE EDUCATION

- Canadian Institute of Marketing, Corporate Finance, 1971-73
- Hydro-Quebec, "Capital Budgeting Under Uncertainty," 1974-75
- Institute of Certified Public Accountants, Mergers & Acquisitions, 1975-78
- Investment Dealers Association of Canada, 1977-78
- Financial Research Foundation, bi-annual seminar, 1975-79
- Advanced Management Research (AMR), faculty member, 1977-80
- Financial Analysts Federation, Educational chapter: "Financial Futures Contracts" seminar
- Exnet Inc. a.k.a. The Management Exchange Inc., faculty member 1981-2008:

National Seminars: *Risk and Return on Capital Projects*
Cost of Capital for Regulated Utilities
Capital Allocation for Utilities
Alternative Regulatory Frameworks
Utility Directors' Workshop
Shareholder Value Creation for Utilities
Fundamentals of Utility Finance
Contemporary Issues in Utility Finance

- SNL Center for Financial Education, faculty member 2008-2016.
 National Seminars: *Essentials of Utility Finance*
- Georgia State University College of Business, Management Development Program, faculty member, 1981-1994.

EXPERT TESTIMONY & UTILITY CONSULTING AREAS OF EXPERTISE

Corporate Finance
 Rate of Return
 Capital Structure
 Generic Cost of Capital
 Costing Methodology
 Depreciation
 Flow-Through vs Normalization

Revenue Requirements Methodology
Utility Capital Expenditures Analysis
Risk Analysis
Capital Allocation
Divisional Cost of Capital, Unbundling
Incentive Regulation & Alternative Regulatory Plans
Shareholder Value Creation
Value-Based Management

REGULATORY BODIES

Alabama Public Service Commission
Alaska Regulatory Commission
Alberta Public Service Board
Arizona Corporation Commission
Arkansas Public Service Commission
British Columbia Board of Public Utilities
California Public Service Commission
Canadian Radio-Television & Telecommunications Comm.
City of New Orleans Council
Colorado Public Utilities Commission
Delaware Public Service Commission
District of Columbia Public Service Commission
Federal Communications Commission
Federal Energy Regulatory Commission
Florida Public Service Commission
Georgia Public Service Commission
Georgia Senate Committee on Regulated Industries
Hawaii Public Utilities Commission
Illinois Commerce Commission
Indiana Utility Regulatory Commission
Iowa Utilities Board
Kentucky Public Service Commission
Louisiana Public Service Commission
Maine Public Utilities Commission
Manitoba Board of Public Utilities
Maryland Public Service Commission
Michigan Public Service Commission
Minnesota Public Utilities Commission
Mississippi Public Service Commission
Missouri Public Service Commission
Montana Public Service Commission
National Energy Board of Canada
Nebraska Public Service Commission
Nevada Public Utilities Commission
New Brunswick Board of Public Commissioners
New Hampshire Public Utilities Commission

New Jersey Board of Public Utilities
New Mexico Public Regulation Commission
New Orleans City Council
New York Public Service Commission
Newfoundland Board of Commissioners of Public Utilities
North Carolina Utilities Commission
Nova Scotia Board of Public Utilities
Ohio Public Utilities Commission
Oklahoma Corporation Commission
Ontario Telephone Service Commission
Ontario Energy Board
Oregon Public Utility Service Commission
Pennsylvania Public Utility Commission
Quebec Regie de l'Energie
Quebec Telephone Service Commission
South Carolina Public Service Commission
South Dakota Public Utilities Commission
Tennessee Regulatory Authority
Texas Public Utility Commission
Utah Public Service Commission
Vermont Department of Public Services
Virginia State Corporation Commission
Washington Utilities & Transportation Commission
West Virginia Public Service Commission

SERVICE AS EXPERT WITNESS

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Southern Bell, So. Carolina PSC, Docket #82-294C
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Citizens Utilities Arizona gas division 1993
PSI Resources 1993-5
CILCORP gas division 1994
GTE Northwest Oregon 1993
Stentor Group 1994-5
Bell Canada 1994-1995
PSI Energy 1993, 1994, 1995, 1999
Cincinnati Gas & Electric 1994, 1996, 1999, 2004
Southern States Utilities, 1995
CILCO 1995, 1999, 2001
Commonwealth Telephone 1996
Edison International 1996, 1998
Citizens Utilities 1997
Stentor Companies 1997
Hydro-Quebec 1998
Entergy Gulf States Louisiana 1998, 1999, 2001, 2002, 2003
Detroit Edison, 1999, 2003
Entergy Gulf States, Texas, 2000, 2004
Hydro Quebec TransEnergie, 2001, 2004
Sierra Pacific Company, 2000, 2001, 2002, 2007, 2010
Nevada Power Company, 2001
Mid American Energy, 2001, 2002
Entergy Louisiana Inc. 2001, 2002, 2004
Mississippi Power Company, 2001, 2002, 2007
Oklahoma Gas & Electric Company, 2002 -2003
Public Service Electric & Gas, 2001, 2002
NUI Corp (Elizabethtown Gas Company), 2002
Jersey Central Power & Light, 2002
San Diego Gas & Electric, 2002, 2012, 2014
New Brunswick Power, 2002
Entergy New Orleans, 2002, 2008
Hydro-Quebec Distribution 2002
PSI Energy 2003
Fortis – Newfoundland Power & Light 2002
Emera – Nova Scotia Power 2004
Hydro-Quebec TransEnergie 2004
Hawaiian Electric 2004
Missouri Gas Energy 2004
AGL Resources 2004
Arkansas Western Gas 2004
Public Service of New Hampshire 2005
Hawaiian Electric Company 2005, 2008, 2009
Delmarva Power & Light Company 2005, 2009

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 Southern California Gas, California PUC, 2012, Docket A-12-04
 Puget Sound Electric
 Puget Sound Electric
 Duke Energy of Ohio
 Duke Energy of Kentucky
 Duke Energy of Ohio
 Dayton Power & Light
 Missouri American Water
 California Power Electric Company

PROFESSIONAL AND LEARNED SOCIETIES

- Engineering Institute of Canada, 1967-1972
- Canada Council Award, recipient 1971 and 1972
- Canadian Association Administrative Sciences, 1973-80
- American Association of Decision Sciences, 1974-1978
- American Finance Association, 1975-2002
- Financial Management Association, 1978-2002

ACTIVITIES IN PROFESSIONAL ASSOCIATIONS AND MEETINGS

- Chairman of meeting on "New Developments in Utility Cost of Capital", Southern Finance Association, Atlanta, Nov. 1982
- Chairman of meeting on "Public Utility Rate of Return", Southeastern Public Utility Conference, Atlanta, Oct. 1982
- Chairman of meeting on "Current Issues in Regulatory Finance", Financial Management Association, Atlanta, Oct. 1983
- Chairman of meeting on "Utility Cost of Capital", Financial Management Association, Toronto, Canada, Oct. 1984.
- Committee on New Product Development, FMA, 1985
- Discussant, "Tobin's Q Ratio", paper presented at Financial Management Association, New York, N.Y., Oct. 1986
- Guest speaker, "Utility Capital Structure: New Developments", National Society of Rate of Return Analysts 18th Financial Forum, Wash., D.C. Oct. 1986
- Opening address, "Capital Expenditures Analysis: Methodology vs Mythology," Bellcore Economic Analysis Conference, Naples FL, 1988.
- Guest speaker, "Mythology in Regulatory Finance", Society of Utility Rate of Return Analysts (SURFA), Annual Conference, Wash., D.C. February 2007.

PAPERS PRESENTED:

"An Empirical Study of Multi-Period Asset Pricing," annual meeting of Financial Management Assoc., Las Vegas Nevada, 1987.

"Utility Capital Expenditures Analysis: Net Present Value vs Revenue Requirements", annual meeting of Financial Management Assoc., Denver, Colorado, October 1985.

"Intervention Analysis and the Dynamics of Market Efficiency", annual meeting of Financial Management Assoc., San Francisco, Oct. 1982

"Intertemporal Market-Line Theory: An Empirical Study," annual meeting of Eastern Finance Assoc., Newport, R.I. 1981

"Option Writing for Financial Institutions: A Cost-Benefit Analysis", 1979 annual meeting Financial Research Foundation

"Free-lunch on the Toronto Stock Exchange", annual meeting of Financial Research Foundation of Canada, 1978.

"Simulation System Computer Software SIMFIN", HP International Business Computer Users Group, London, 1975.

"Inflation Accounting: Implications for Financial Analysis." Institute of Certified Public Accountants Symposium, 1979.

OFFICES IN PROFESSIONAL ASSOCIATIONS

- President, International Hewlett-Packard Business Computers Users Group, 1977
- Chairman Program Committee, International HP Business Computers Users Group, London, England, 1975
- Program Coordinator, Canadian Assoc. of Administrative Sciences, 1976
- Member, New Product Development Committee, Financial Management Association, 1985-1986
- Reviewer: Journal of Financial Research
Financial Management
Financial Review
Journal of Finance

PUBLICATIONS

"Risk Aversion Revisited", Journal of Finance, Sept. 1983

"Hedging Regulatory Lag with Financial Futures," Journal of Finance, May 1983. (with G. Gay, R. Kolb)

"The Effect of CWIP on Cost of Capital," Public Utilities Fortnightly, July 1986.

"The Effect of CWIP on Revenue Requirements" Public Utilities Fortnightly, August 1986.

"Intervention Analysis and the Dynamics of Market Efficiency," Time-Series Applications, New York: North Holland, 1983. (with K. El-Sheshai)

"Market-Line Theory and the Canadian Equity Market," Journal of Business Administration, Jan. 1982, M. Brennan, editor

"Efficiency of Canadian Equity Markets," International Management Review, Feb. 1978.

"Intertemporal Market-Line Theory: An Empirical Test," Financial Review, Proceedings of the Eastern Finance Association, 1981.

BOOKS

Utilities' Cost of Capital, Public Utilities Reports Inc., Arlington, Va., 1984.

Regulatory Finance, Public Utilities Reports Inc., Arlington, Va., 2004

Driving Shareholder Value, McGraw-Hill, January 2001.

The New Regulatory Finance, Public Utilities Reports Inc., Arlington, Va., 2006.

MONOGRAPHS

Determining Cost of Capital for Regulated Industries, Public Utilities Reports, Inc., and The Management Exchange Inc., 1982 - 1993. (with V.L. Andrews)

Alternative Regulatory Frameworks, Public Utilities Reports, Inc., and The Management Exchange Inc., 1993. (with V.L. Andrews)

Risk and Return in Capital Projects, The Management Exchange Inc., 1980. (with B. Deschamps)

Utility Capital Expenditure Analysis, The Management Exchange Inc., 1983.

Regulation of Cable Television: An Econometric Planning Model, Quebec Department of Communications, 1978.

"An Economic & Financial Profile of the Canadian Cablevision Industry," Canadian Radio-Television & Telecommunication Commission (CRTC), 1978.

Computer Users' Manual: Finance and Investment Programs, University of Montreal Press, 1974, revised 1978.

Fiber Optics Communications: Economic Characteristics, Quebec Department of Communications, 1978.

"Canadian Equity Market Inefficiencies", Capital Market Research Memorandum, Garmaise & Thomson Investment Consultants, 1979.

MISCELLANEOUS CONSULTING REPORTS

"Operational Risk Analysis: California Water Utilities," Calif. Water Association, 1993.

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	VERTICALLY INTEGRATED ELECTRIC UTILITIES	PARENT CO.	GAS	ELEC
	(1)	(2)	(3)	(4)
1	Indiana Michigan Power Company Baa1 Stable	AEP		Y
2	Indianapolis Power & Light Co. Baa1 Stable	AES Corp		
3	ALLETE, Inc. A3 Stable	ALLETE		Y
4	Interstate Power and Light Co. Baa1 Stable	Alliant	Y	
5	Union Electric Company Baa1 Stable	Ameren	Y	
6	Avista Corp. Baa1 Stable	Avista	Y	
7	Black Hills Power, Inc. A3 Stable	Black Hills	Y	
8	Consumers Energy Company (P)A3 Positive	CMS Energy	Y	
9	Virginia Electric and Power Co. A2 Stable	Dominion Energy	Y	
10	Dayton Power & Light Company Baa3 Negative	DP&L		
11	DTE Electric Company A2 Stable	DTE Energy	Y	
12	Duke Energy Carolinas, LLC A1 Stable	Duke Energy	Y	
13	Southern California Edison Co. A2 Stable	Edison		Y
14	El Paso Electric Company Baa1 Stable	El Paso Elec		Y
15	Tampa Electric Company A3 Stable	Emera		Y
16	Empire District Electric Company Baa1 Stable	Empire District	Y	
17	Entergy Arkansas, Inc. Baa1 Stable	Entergy	Y	
18	Public Service Company of New Hampshire A3 Stable	Evesource Energy	Y	
19	Monongahela Power Company Baa2 Stable	First Energy		Y
20	Tucson Electric Power Company A3 Stable	Fortis		Y
21	Kansas City Power & Light Co. Baa1 Stable	Great Plains		Y
22	Hawaiian Electric Company, Inc. Baa2 Stable	Hawaiian Electric		Y
23	Idaho Power Company A3 Stable	IDACORP		Y
24	Madison Gas and Electric Company A1 Stable	MGE Energy	Y	
25	Florida Power & Light Company A1 Stable	Next Era		Y
26	Northern Indiana Public Service Co Baa1 Stable	NiSource	Y	
27	NorthWestern Corporation A3 Negative	Northwestern Corp	Y	
28	Oklahoma Gas & Electric Company A1 Stable	OG&E		Y
29	Otter Tail Power Company A3 Stable	Otter Tail		Y
30	Pacific Gas & Electric Company A3 Positive	PG&E	Y	
31	Arizona Public Service Company A2 Stable	Pinnacle West		Y
32	Public Service Company of New Mexico Baa2 Stable	PNM Resources		Y
33	Portland General Electric Company A3 Stable	Portland General		Y
34	Kentucky Utilities Company A3 Stable	PPL Corp		Y
35	South Carolina Electric & Gas Co. Baa2 Stable	SCANA	Y	
36	Alabama Power Company A1 Stable	Southern Co		Y
37	Southern Indiana Gas & Electric A2 Stable	Vectren	Y	
38	Wisconsin Electric Power Company A1 Negative	WEC Energy	Y	
39	Westar Energy, Inc. Baa1 Stable	Westar		Y
40	Northern States Power Company (Minnesota) A2 Stable	Xcel	Y	

Source: Moody's Investor Service, "2017 Outlook - Timely Cost-Recovery Drives Stable Outlook", 11/16
Value Line Investment Survey Investment Reports 9/2017

Proxy Group for OG&E

	Company	Ticker
1	AEP	AEP
2	ALLETE	ALE
3	Edison	EIX
4	El Paso Elec	EE
5	Emera	EMA
6	Fortis	FTS
7	Hawaiian Electric	HE
8	IDACORP	IDA
9	Next Era	NEE
10	OG&E	OGE
11	Otter Tail	OTTR
12	Pinnacle West	PNW
13	PNM Resources	PNM
14	Portland General	POR
15	PPL Corp	PPL
16	Southern Co	SO
17	Westar	WR

**Vertically Integrated Electric Utilities
DCF Analysis Value Line Growth Rates**

	(1)	(2)	(3)	(4)	(5)	(6)
			Projected	% Expected		
Line	Dividend	EPS	Divid	Cost of		
No. Company Name	Yield	Growth	Yield	Equity	ROE	
1 AEP	3.30	4.00	3.43	7.43	7.61	
2 ALLETE	2.80	6.00	2.97	8.97	9.12	
3 Edison	3.00	4.00	3.12	7.12	7.28	
4 El Paso Elec	2.40	5.00	2.52	7.52	7.65	
5 Emera	4.40	10.00	4.84	14.84	15.09	
6 Fortis	3.70	9.00	4.03	13.03	13.25	
7 Hawaiian Electric	3.60	1.50	3.65	5.15	5.35	
8 IDACORP	2.60	3.50	2.69	6.19	6.33	
9 Next Era	2.80	7.00	3.00	10.00	10.15	
10 OG&E	3.70	6.00	3.92	9.92	10.13	
11 Otter Tail	3.10	6.50	3.30	9.80	9.98	
12 Pinnacle West	3.20	5.50	3.38	8.88	9.05	
13 PNM Resources	2.50	7.50	2.69	10.19	10.33	
14 Portland General	3.10	6.00	3.29	9.29	9.46	
15 PPL Corp	4.20	5.00	4.41	9.41	9.64	
16 Southern Co	4.80	3.50	4.97	8.47	8.73	
17 Westar	3.20	6.00	3.39	9.39	9.57	
19 AVERAGE	3.32	5.65	3.51	9.15	9.34	

Notes:

- 22 Column 1, 2, 3: Value Line Investment Reports 11/2017
- 23 Column 4 = Column 2 times (1 + Column 3/100)
- 24 Column 5 = Column 4 + Column 3
- 25 Column 6 = Column 4/0.95 + Column 3
- 26 No growth forecast available for PPL Corp.
- 27 The growth forecast for PPL Corp is from Zacks Investment Research

**Vertically Integrated Electric Utilities
DCF Analysis Analysts' Growth Forecasts**

Line No.	(1) Company Name	(2) Dividend Yield	(3) Analysts' % Expected		(5) Cost of Equity	(6) ROE
			Growth Forecast	Divid Yield		
1	AEP	3.30	5.40	3.48	8.88	9.06
2	ALLETE	2.80	6.10	2.97	9.07	9.23
3	Edison	3.00	6.30	3.19	9.49	9.66
4	El Paso Elec	2.40	7.20	2.57	9.77	9.91
5	Emera	4.40	10.00	4.84	14.84	15.09
6	Fortis	3.70	5.50	3.90	9.40	9.61
7	Hawaiian Electric	3.60	4.00	3.74	7.74	7.94
8	IDACORP	2.60	4.50	2.72	7.22	7.36
9	Next Era	2.80	7.40	3.01	10.41	10.57
10	OG&E	3.70	5.30	3.90	9.20	9.40
11	Otter Tail	3.10	6.50	3.30	9.80	9.98
12	Pinnacle West	3.20	5.20	3.37	8.57	8.74
13	PNM Resources	2.50	4.70	2.62	7.32	7.46
14	Portland General	3.10	3.50	3.21	6.71	6.88
15	PPL Corp	4.20	5.00	4.41	9.41	9.64
16	Southern Co	4.80	4.30	5.01	9.31	9.57
17	Westar	3.20	4.00	3.33	7.33	7.50
19	AVERAGE	3.32	5.58	3.50	9.09	9.27

Notes:

- 22 Column 1, 2: Value Line Investment Reports 11/2017
23 Column 3: Zacks Investment Research growth forecast 11/2017
24 Column 4 = Column 2 times (1 + Column 3/100)
25 Column 5 = Column 4 + Column 3
26 Column 6 = Column 4/0.95 + Column 3
27 No growth forecast available for Emera and Otter Tail.
28 The growth forecast for PPL Corp is from Value Line

Integrated Electric Utilities Beta Estimates

	(1)	(2)
<u>Line No.</u>	<u>Company Name</u>	<u>Beta</u>
1	AEP	0.65
2	ALLETE	0.75
3	Edison	0.65
4	El Paso Elec	0.80
5	Emera	0.60
6	Fortis	0.70
7	Hawaiian Electric	0.70
8	IDACORP	0.70
9	Next Era	0.65
10	OG&E	0.95
11	Otter Tail	0.90
12	Pinnacle West	0.65
13	PNM Resources	0.75
14	Portland General	0.70
15	PPL Corp	0.70
16	Southern Co	0.55
17	Westar	0.70
19	AVERAGE	0.71
21	Source: Value Line Investment Reports 11/2017	

2016 Utility Industry Historical Risk Premium

Line No.	Year	(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)
		Long-Term Government Bond Yield	Long-Term Government Income Component Bond Yield	20 year Maturity Bond Value	Gain/Loss	Interest	Bond Total Return	S&P Utility Index Return	Utility Equity Risk Premium Over Bond Returns	Utility Equity Risk Premium Over Bond Return Income Component
1	1931	4.07%	3.33%	1,000.00						
2	1932	3.15%	3.69%	1,135.75	135.75	40.70	17.64%	-0.54%	-18.18%	-4.23%
3	1933	3.36%	3.12%	969.60	-30.40	31.50	0.11%	-21.87%	-21.98%	-24.99%
4	1934	2.93%	3.10%	1,064.73	64.73	33.60	9.83%	-20.41%	-30.24%	-23.51%
5	1935	2.76%	2.81%	1,025.99	25.99	29.30	5.53%	76.63%	71.10%	73.82%
6	1936	2.56%	2.77%	1,031.15	31.15	27.60	5.88%	20.69%	14.81%	17.92%
7	1937	2.73%	2.66%	973.93	-26.07	25.60	-0.05%	-37.04%	-36.99%	-39.70%
8	1938	2.52%	2.64%	1,032.83	32.83	27.30	6.01%	22.45%	16.44%	19.81%
9	1939	2.26%	2.40%	1,041.65	41.65	25.20	6.68%	11.26%	4.58%	8.86%
10	1940	1.94%	2.23%	1,052.84	52.84	22.60	7.54%	-17.15%	-24.69%	-19.38%
11	1941	2.04%	1.94%	983.64	-16.36	19.40	0.30%	-31.57%	-31.87%	-33.51%
12	1942	2.46%	2.46%	933.97	-66.03	20.40	-4.56%	15.39%	19.95%	12.93%
13	1943	2.48%	2.44%	996.86	-3.14	24.60	2.15%	46.07%	43.92%	43.63%
14	1944	2.46%	2.46%	1,003.14	3.14	24.80	2.79%	18.03%	15.24%	15.57%
15	1945	1.99%	2.34%	1,077.23	77.23	24.60	10.18%	53.33%	43.15%	50.99%
16	1946	2.12%	2.04%	978.90	-21.10	19.90	-0.12%	1.26%	1.38%	-0.78%
17	1947	2.43%	2.13%	951.13	-48.87	21.20	-2.77%	-13.16%	-10.39%	-15.29%
18	1948	2.37%	2.40%	1,009.51	9.51	24.30	3.38%	4.01%	0.63%	1.61%
19	1949	2.09%	2.25%	1,045.58	45.58	23.70	6.93%	31.39%	24.46%	29.14%
20	1950	2.24%	2.12%	975.93	-24.07	20.90	-0.32%	3.25%	3.57%	1.13%
21	1951	2.69%	2.38%	930.75	-69.25	22.40	-4.69%	18.63%	23.32%	16.25%
22	1952	2.79%	2.68%	984.75	-15.25	26.90	1.17%	19.25%	18.08%	16.57%
23	1953	2.74%	2.84%	1,007.66	7.66	27.90	3.56%	7.85%	4.29%	5.01%
24	1954	2.72%	2.79%	1,003.07	3.07	27.40	3.05%	24.72%	21.67%	21.93%
25	1955	2.95%	2.75%	965.44	-34.56	27.20	-0.74%	11.26%	12.00%	8.51%
26	1956	3.45%	2.99%	928.19	-71.81	29.50	-4.23%	5.06%	9.29%	2.07%
27	1957	3.23%	3.44%	1,032.23	32.23	34.50	6.67%	6.36%	-0.31%	2.92%
28	1958	3.82%	3.27%	918.01	-81.99	32.30	-4.97%	40.70%	45.67%	37.43%
29	1959	4.47%	4.01%	914.65	-85.35	38.20	-4.71%	7.49%	12.20%	3.48%
30	1960	3.80%	4.26%	1,093.27	93.27	44.70	13.80%	20.26%	6.46%	16.00%
31	1961	4.15%	3.83%	952.75	-47.25	38.00	-0.92%	29.33%	30.25%	25.50%

2016 Utility Industry Historical Risk Premium

Line No.	Year	(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)
		Long-Term Government Bond Yield	Long-Term Government Income Component Bond Yield	20 year Maturity Bond Value	Gain/Loss	Interest	Bond Total Return	S&P Utility Index Return	Utility Equity Risk Premium Over Bond Returns	Utility Equity Risk Premium Over Bond Return Income Component
32	1962	3.95%	4.00%	1,027.48	27.48	41.50	6.90%	-2.44%	-9.34%	-6.44%
33	1963	4.17%	3.89%	970.35	-29.65	39.50	0.99%	12.36%	11.37%	8.47%
34	1964	4.23%	4.15%	991.96	-8.04	41.70	3.37%	15.91%	12.54%	11.76%
35	1965	4.50%	4.20%	964.64	-35.36	42.30	0.69%	4.67%	3.98%	0.47%
36	1966	4.55%	4.49%	993.48	-6.52	45.00	3.85%	-4.48%	-8.33%	-8.97%
37	1967	5.56%	4.59%	879.01	-120.99	45.50	-7.55%	-0.63%	6.92%	-5.22%
38	1968	5.98%	5.50%	951.38	-48.62	55.60	0.70%	10.32%	9.62%	4.82%
39	1969	6.87%	5.96%	904.00	-96.00	59.80	-3.62%	-15.42%	-11.80%	-21.38%
40	1970	6.48%	6.74%	1,043.38	43.38	68.70	11.21%	16.56%	5.35%	9.82%
41	1971	5.97%	6.32%	1,059.09	59.09	64.80	12.39%	2.41%	-9.98%	-3.91%
42	1972	5.99%	5.87%	997.69	-2.31	59.70	5.74%	8.15%	2.41%	2.28%
43	1973	7.26%	6.51%	867.09	-132.91	59.90	-7.30%	-18.07%	-10.77%	-24.58%
44	1974	7.60%	7.27%	965.33	-34.67	72.60	3.79%	-21.55%	-25.34%	-28.82%
45	1975	8.05%	7.99%	955.63	-44.37	76.00	3.16%	44.49%	41.33%	36.50%
46	1976	7.21%	4.89%	1,088.25	88.25	80.50	16.87%	31.81%	14.94%	26.92%
47	1977	8.03%	7.14%	919.03	-80.97	72.10	-0.89%	8.64%	9.53%	1.50%
48	1978	8.98%	7.90%	912.47	-87.53	80.30	-0.72%	-3.71%	-2.99%	-11.61%
49	1979	10.12%	8.86%	902.99	-97.01	89.80	-0.72%	13.58%	14.30%	4.72%
50	1980	11.99%	9.97%	859.23	-140.77	101.20	-3.96%	15.08%	19.04%	5.11%
51	1981	13.34%	11.55%	906.45	-93.55	119.90	2.63%	11.74%	9.11%	0.19%
52	1982	10.95%	13.50%	1,192.38	192.38	133.40	32.58%	26.52%	-6.06%	13.02%
53	1983	11.97%	10.38%	923.12	-76.88	109.50	3.26%	20.01%	16.75%	9.63%
54	1984	11.70%	11.74%	1,020.70	20.70	119.70	14.04%	26.04%	12.00%	14.30%
55	1985	9.56%	11.25%	1,189.27	189.27	117.00	30.63%	33.05%	2.42%	21.80%
56	1986	7.89%	8.98%	1,166.63	166.63	95.60	26.22%	28.53%	2.31%	19.55%
57	1987	9.20%	7.92%	881.17	-118.83	78.90	-3.99%	-2.92%	1.07%	-10.84%
58	1988	9.19%	8.97%	1,000.91	0.91	92.00	9.29%	18.27%	8.98%	9.30%
59	1989	8.16%	8.10%	1,100.73	100.73	91.90	19.26%	47.80%	28.54%	39.70%
60	1990	8.44%	8.19%	973.17	-26.83	81.60	5.48%	-2.57%	-8.05%	-10.76%

2016 Utility Industry Historical Risk Premium

Line No.	Year	(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)
		Long-Term Government Bond Yield	Long-Term Government Income Component Bond Yield	20 year Maturity Bond Value	Gain/Loss	Interest	Bond Total Return	S&P Utility Index Return	Utility Equity Risk Premium Over Bond Returns	Utility Equity Risk Premium Over Bond Return Income Component
61	1991	7.30%	8.22%	1,118.94	118.94	84.40	20.33%	14.61%	-5.72%	6.39%
62	1992	7.26%	7.26%	1,004.19	4.19	73.00	7.72%	8.10%	0.38%	0.84%
63	1993	6.54%	7.17%	1,079.70	79.70	72.60	15.23%	14.41%	-0.82%	7.24%
64	1994	7.99%	6.59%	856.40	-143.60	65.40	-7.82%	-7.94%	-0.12%	-14.53%
65	1995	6.03%	7.60%	1,225.98	225.98	79.90	30.59%	42.15%	11.56%	34.55%
66	1996	6.73%	6.18%	923.67	-76.33	60.30	-1.60%	3.14%	4.74%	-3.04%
67	1997	6.02%	6.64%	1,081.92	81.92	67.30	14.92%	24.69%	9.77%	18.05%
68	1998	5.42%	5.83%	1,072.71	72.71	60.20	13.29%	14.82%	1.53%	8.99%
69	1999	6.82%	5.57%	848.41	-151.59	54.20	-9.74%	-8.85%	0.89%	-14.42%
70	2000	5.58%	6.50%	1,148.30	148.30	68.20	21.65%	59.70%	38.05%	53.20%
71	2001	5.75%	5.53%	979.95	-20.05	55.80	3.57%	-30.41%	-33.98%	-35.94%
72	2002	4.84%	5.59%	1,115.77	115.77	57.50	17.33%	-30.04%	-47.37%	-35.63%
73	2003	5.11%	4.80%	966.42	-33.58	48.40	1.48%	26.11%	24.63%	21.31%
74	2004	4.84%	5.02%	1,034.35	34.35	51.10	8.54%	24.22%	15.68%	19.20%
75	2005	4.61%	4.69%	1,029.84	29.84	48.40	7.82%	16.79%	8.97%	12.10%
76	2006	4.91%	4.68%	962.06	-37.94	46.10	0.82%	20.95%	20.13%	16.27%
77	2007	4.50%	4.86%	1,053.70	53.70	49.10	10.28%	19.36%	9.08%	14.50%
78	2008	3.03%	4.45%	1,219.28	219.28	45.00	26.43%	-28.99%	-55.42%	-33.44%
79	2009	4.58%	3.47%	798.39	-201.61	30.30	-17.13%	11.94%	29.07%	8.47%
80	2010	4.14%	4.25%	1,059.45	59.45	45.80	10.52%	5.49%	-5.03%	1.24%
81	2011	2.48%	3.81%	1,260.50	260.50	41.40	30.19%	19.88%	-10.31%	16.07%
82	2012	2.41%	2.40%	1,011.06	11.06	24.80	3.59%	1.99%	-1.60%	-0.41%
83	2013	3.67%	2.86%	822.57	-177.43	24.10	-15.33%	13.26%	28.59%	10.40%
84	2014	2.40%	3.12%	1,200.79	200.79	36.70	23.75%	28.61%	4.86%	25.49%
85	2015	2.84%	2.84%	933.21	-66.79	24.00	-4.28%	1.38%	5.66%	-1.46%
86	2016	2.80%	2.71%	1,006.09	6.09	28.40	3.45%	11.93%	8.48%	9.22%
87	Mean								5.5%	6.1%
89	Source:	Bloomberg Web site: Standard & Poors Utility Stock Index % Annual Change, Jan. to Dec.								
90		Bond yields from Ibbotson SBBi 2015 Classic Yearbook (Morningstar) Table A-9 Long-Term Government Bonds Yields								

Equity Risk Premium - Treasury Bond

Direct Exhibit RAM-8

Page 1 of 1

<u>Line</u>	<u>Date</u>	<u>Treasury Bond Yield¹</u>	<u>Authorized Electric Returns²</u>	<u>Indicated Risk Premium</u>
		(1)	(2)	(3)
1	1986	7.80%	13.93%	6.1%
2	1987	8.58%	12.99%	4.4%
3	1988	8.96%	12.79%	3.8%
4	1989	8.45%	12.97%	4.5%
5	1990	8.61%	12.70%	4.1%
6	1991	8.14%	12.55%	4.4%
7	1992	7.67%	12.09%	4.4%
8	1993	6.60%	11.41%	4.8%
9	1994	7.37%	11.34%	4.0%
10	1995	6.88%	11.55%	4.7%
11	1996	6.70%	11.39%	4.7%
12	1997	6.61%	11.40%	4.8%
13	1998	5.58%	11.66%	6.1%
14	1999	5.87%	10.77%	4.9%
15	2000	5.94%	11.43%	5.5%
16	2001	5.49%	11.09%	5.6%
17	2002	5.42%	11.16%	5.7%
18	2003	5.02%	10.97%	6.0%
19	2004	5.05%	10.75%	5.7%
20	2005	4.65%	10.54%	5.9%
21	2006	4.88%	10.36%	5.5%
22	2007	4.83%	10.36%	5.5%
23	2008	4.28%	10.46%	6.2%
24	2009	4.07%	10.48%	6.4%
25	2010	4.25%	10.34%	6.1%
26	2011	3.91%	10.29%	6.4%
27	2012	2.92%	10.17%	7.3%
28	2013	3.45%	10.03%	6.6%
29	2014	3.34%	9.91%	6.6%
30	2015	2.84%	9.85%	7.0%
31	2016	2.60%	9.77%	7.2%
33	Average	5.70%	11.21%	5.51%

Sources:

1 Fed Reserve Board of Governors H.15 Release, 30-Yr Treasury Rate

2 S&P Global Intelligence (Regulatory Research Associates)

Major Rate Case Decisions 1986-2016

Operating Company Capital Structure

Operating Company	Parent	2017Q3 Equity Percentage
Appalachian Power Company	AEP	48.30%
Indiana Michigan Power Company	AEP	46.65%
Kentucky Power Company	AEP	43.22%
Kingsport Power Company	AEP	45.88%
Ohio Power Company	AEP	57.64%
Public Service Company of Oklahoma	AEP	48.85%
Southwestern Electric Power Company	AEP	48.66%
Wheeling Power Company	AEP	54.13%
ALLETE (Minnesota Power)	ALE	59.73%
Superior Water, Light and Power Company	ALE	62.33%
Southern California Edison Company	EIX	53.19%
El Paso Electric Company	EE	49.81%
Tampa Electric Company	EMA	57.00%
Tucson Electric Power Company	FTS	53.56%
Hawaiian Electric Company, Inc. ¹	HE	58.02%
Florida Power & Light Company	NEE	63.00%
OG&E	OGE	53.05%
Kentucky Utilities Company	PPL	53.93%
Alabama Power Company	SO	48.01%
Georgia Power Company	SO	50.34%
Gulf Power Company	SO	54.97%
Mississippi Power Company	SO	47.34%
Idaho Power Co.	IDA	54.22%
Otter Tail Power Company	OTTR	57.24%
Public Service Company of New Mexico	PNM	47.59%
Texas-New Mexico Power Company ¹	PNM	55.45%
Arizona Public Service Company	PNW	53.05%
Portland General Electric Company	POR	50.17%
Kansas Gas and Electric Company	WR	74.21%
Westar Energy (KPL)	WR	58.87%
Mean		53.61%

Source: SNL Financial

1) Equity percentages for Texas-New Mexico Power Company and Hawaiian Electric Company, Inc derived from their 10Q filings, all others - from FERC Form No. 3-Q

S&P Investment Risk Matrix

Business Risk/Financial Risk						
Business Risk Profile	Financial Risk Profile					
	Minimal	Modest	Intermediate	Significant	Aggressive	Highly Leveraged
Excellent	AAA/AA+	AA	A	A-	BBB	
Strong	AA	A	A-	BBB	BB	BB-
Satisfactory	A-	BBB+	BBB	BB+	BB-	B+
Fair		BBB-	BB+	BB	BB-	B
Weak			BB	BB-	B+	B-
Vulnerable				B+	B	B- or below

S&P Financial Risk Indicators

Financial Risk Indicative Ratios			
	Financial Risk Profile		
	FFO/debt %	Debt/EBITDA x	Debt/Capital %
Minimal	>60	<1.5	<25
Modest	45-60	1.5-2.0	25-35
Intermediate	30-45	2.0-3.0	35-45
Significant	20-30	3.0-4.0	45-50
Aggressive	12-20	4.0-5.0	50-60
Highly Leveraged	<12	>5.0	>60

Moody's Financial Risk Indicators

Financial Risk Ratios			
	Financial Risk Benchmarks		
	CFO/debt %	CFO/interest x	Tot debt/capital %
Aaa	>40	>8.0	<25
Aa	30-50	6.0-8.0	25-35
A	22-30	4.5-6.0	35-45
Baa	13-22	2.7-4.5	45-55
Ba	21-6	1.5-2.7	55-65
B	<5	<1.5	>65

APPENDIX A
CAPM, EMPIRICAL CAPM

The Capital Asset Pricing Model (CAPM) is a fundamental paradigm of finance. Simply put, the fundamental idea underlying the CAPM is that risk-averse investors demand higher returns for assuming additional risk, and higher-risk securities are priced to yield higher expected returns than lower-risk securities. The CAPM quantifies the additional return, or risk premium, required for bearing incremental risk. It provides a formal risk-return relationship anchored on the basic idea that only market risk matters, as measured by beta. According to the CAPM, securities are priced such that their:

$$\text{EXPECTED RETURN} = \text{RISK-FREE RATE} + \text{RISK PREMIUM}$$

Denoting the risk-free rate by R_F and the return on the market as a whole by R_M , the CAPM is:

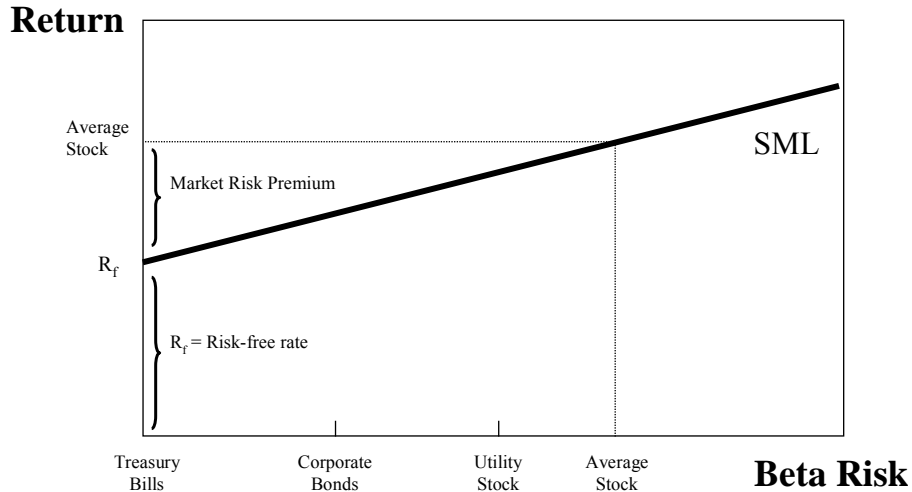
$$K = R_F + \beta(R_M - R_F) \quad (1)$$

Equation 1 is the CAPM expression which asserts that an investor expects to earn a return, K , that could be gained on a risk-free investment, R_F , plus a risk premium for assuming risk, proportional to the security's market risk, also known as beta, β , and the market risk premium, $(R_M - R_F)$, where R_M is the market return. The market risk premium $(R_M - R_F)$ can be abbreviated MRP so that the CAPM becomes:

$$K = R_F + \beta \times \text{MRP} \quad (2)$$

The CAPM risk-return relationship is depicted in the figure below and is typically labeled as the Security Market Line (SML) by the investment community.

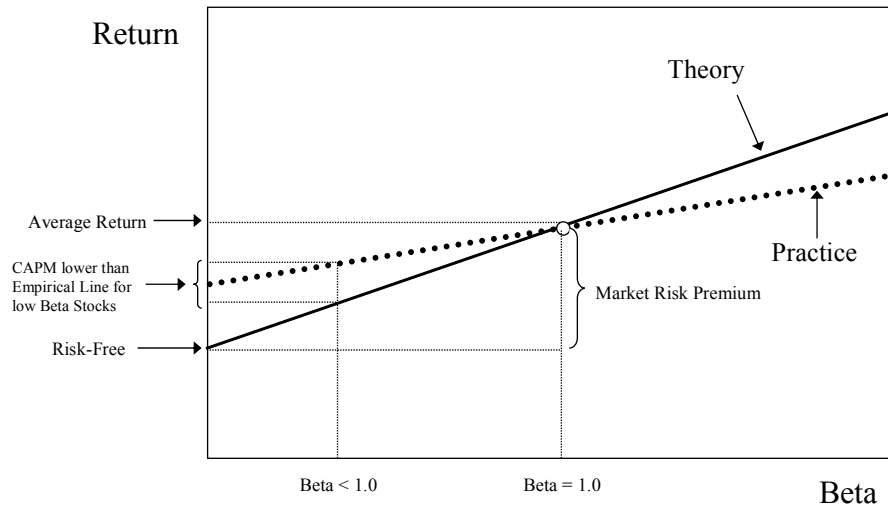
CAPM and Risk - Return in Capital Markets



A myriad empirical tests of the CAPM have shown that the risk-return tradeoff is not as steeply sloped as that predicted by the CAPM, however. That is, low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. In other words, the CAPM tends to overstate the actual sensitivity of the cost of capital to beta: low-beta stocks tend to have higher returns and high-beta stocks tend to have lower risk returns than predicted by the CAPM. The difference between the CAPM and the type of relationship observed in the empirical studies is depicted in the figure below. This is one of the most widely known empirical findings of the finance literature. This extensive literature is summarized in Chapter 13 of Dr. Morin's book [Regulatory Finance, Public Utilities Report Inc., Arlington, VA, 1994].

Risk vs Return

Theory vs. Practice



A number of refinements and expanded versions of the original CAPM theory have been proposed to explain the empirical findings. These revised CAPMs typically produce a risk-return relationship that is flatter than the standard CAPM prediction. The following equation makes use of these empirical findings by flattening the slope of the risk-return relationship and increasing the intercept:

$$K = R_F + \alpha + \beta (MRP - \alpha) \quad (3)$$

where α is the "alpha" of the risk-return line, a constant determined empirically, and the other symbols are defined as before. Alternatively, Equation 3 can be written as follows:

$$K = R_F + a MRP + (1-a) \beta MRP \quad (4)$$

where a is a fraction to be determined empirically. Comparing Equations 3 and 4, it is easy to see that alpha equals 'a' times MRP, that is, $\alpha = a \times MRP$

Theoretical Underpinnings

The obvious question becomes what would produce a risk return relationship which is flatter than the CAPM prediction, or in other words, how do you explain the presence of “alpha” in the above equation. The exclusion of variables aside from beta would produce this result. Three such variables are noteworthy: dividend yield, skewness, and hedging potential.

The dividend yield effects stem from the differential taxation on corporate dividends and capital gains. The standard CAPM does not consider the regularity of dividends received by investors. Utilities generally maintain high dividend payout ratios relative to the market, and by ignoring dividend yield, the CAPM provides biased cost of capital estimates. To the extent that dividend income is taxed at a higher rate than capital gains, investors will require higher pre-tax returns in order to equalize the after-tax returns provided by high-yielding stocks (e.g. utility stocks) with those of low-yielding stocks. In other words, high-yielding stocks must offer investors higher pre-tax returns. Even if dividends and capital gains are undifferentiated for tax purposes, there is still a tax bias in favor of earnings retention (lower dividend payout), as capital gains taxes are paid only when gains are realized.

Empirical studies by Litzenberger and Ramaswamy (1979) and Litzenberger et al. (1980) find that security returns are positively related to dividend yield as well as to beta. These results are consistent with after-tax extensions of the CAPM developed by Breenan (1973) and Litzenberger and Ramaswamy (1979) and suggest that the relationship between return, beta, and dividend yield should be estimated and employed to calculate the cost of equity capital.

As far as skewness is concerned, investors are more concerned with losing money than with total variability of return. If risk is defined as the probability of loss, it appears more logical to measure risk as the probability of achieving a return which is below the expected return. The traditional CAPM provides downward-biased estimates of cost of capital to the extent that these skewness effects are significant. As shown by Kraus and Litzenberger (1976), expected return depends on both on a stock's systematic risk (beta) and the systematic skewness. Empirical studies by Kraus and Litzenberger (1976),

Friend, Westerfield, and Granito (1978), and Morin (1981) found that, in addition to beta, skewness of returns has a significant negative relationship with security returns. This result is consistent with the skewness version of the CAPM developed by Rubinstein (1973) and Kraus and Litzenberger (1976).

This is particularly relevant for public utilities whose future profitability is constrained by the regulatory process on the upside and relatively unconstrained on the downside in the face of socio-political realities of public utility regulation. The process of regulation, by restricting the upward potential for returns and responding sluggishly on the downward side, may impart some asymmetry to the distribution of returns, and is more likely to result in utilities earning less, rather than more, than their cost of capital. The traditional CAPM provides downward-biased estimates of cost of capital to the extent that these skewness effects are significant.

As far as hedging potential is concerned, investors are exposed to another kind of risk, namely, the risk of unfavorable shifts in the investment opportunity set. Merton (1973) shows that investors will hold portfolios consisting of three funds: the risk-free asset, the market portfolio, and a portfolio whose returns are perfectly negatively correlated with the riskless asset so as to hedge against unforeseen changes in the future risk-free rate. The higher the degree of protection offered by an asset against unforeseen changes in interest rates, the lower the required return, and conversely. Merton argues that low beta assets, like utility stocks, offer little protection against changes in interest rates, and require higher returns than suggested by the standard CAPM.

Another explanation for the CAPM's inability to fully explain the process determining security returns involves the use of an inadequate or incomplete market index. Empirical studies to validate the CAPM invariably rely on some stock market index as a proxy for the true market portfolio. The exclusion of several asset categories from the definition of market index mis-specifies the CAPM and biases the results found using only stock market data. Kolbe and Read (1983) illustrate the biases in beta estimates which result from applying the CAPM to public utilities. Unfortunately, no comprehensive and easily accessible data exist for several classes of assets, such as mortgages and business investments, so that the exact relation between return and stock betas predicted by the CAPM does not exist. This suggests that the empirical relationship

between returns and stock betas is best estimated empirically (ECAPM) rather than by relying on theoretical and elegant CAPM models expanded to include missing assets effects. In any event, stock betas may be highly correlated with the true beta measured with the true market index.

Yet another explanation for the CAPM's inability to fully explain the observed risk-return tradeoff involves the possibility of constraints on investor borrowing that run counter to the assumptions of the CAPM. In response to this inadequacy, several versions of the CAPM have been developed by researchers. One of these versions is the so-called zero-beta, or two-factor, CAPM which provides for a risk-free return in a market where borrowing and lending rates are divergent. If borrowing rates and lending rates differ, or there is no risk-free borrowing or lending, or there is risk-free lending but no risk-free borrowing, then the CAPM has the following form:

$$K = R_Z + \beta(R_m - R_F)$$

The model, christened the zero-beta model, is analogous to the standard CAPM, but with the return on a minimum risk portfolio which is unrelated to market returns, R_Z , replacing the risk-free rate, R_F . The model has been empirically tested by Black, Jensen, and Scholes (1972), who found a flatter than predicted CAPM, consistent with the model and other researchers' findings.

The zero-beta CAPM cannot be literally employed in cost of capital projections, since the zero-beta portfolio is a statistical construct difficult to replicate.

Empirical Evidence

A summary of the empirical evidence on the magnitude of alpha is provided in the table below.

Empirical Evidence on the Alpha Factor		
Author	Range of alpha	Period relied
Black (1993)	-3.6% to 3.6%	1931-1991
Black, Jensen and Scholes (1972)	-9.61% to 12.24%	1931-1965
Fama and McBeth (1972)	4.08% to 9.36%	1935-1968
Fama and French (1992)	10.08% to 13.56%	1941-1990
Litzenberger and Ramaswamy (1979)	5.32% to 8.17%	
Litzenberger, Ramaswamy and Sosin (1980)	1.63% to 5.04%	1926-1978
Pettengill, Sundaram and Mathur (1995)	4.6%	
Morin (1994)	2.0%	1926-1984
Harris, Marston, Mishra, and O'Brien (2003)	2.0%	1983-1998

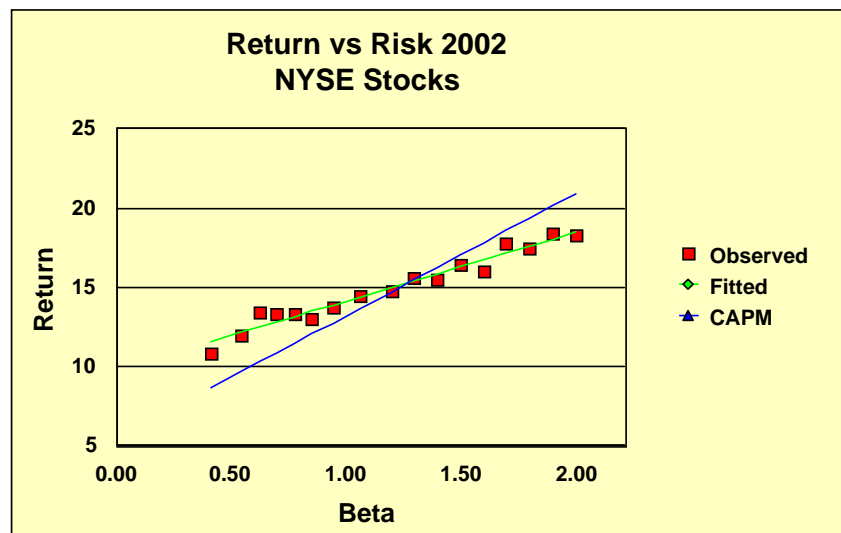
Given the observed magnitude of alpha, the empirical evidence indicates that the risk-return relationship is flatter than that predicted by the CAPM. Typical of the empirical evidence is the findings cited in Morin (1989) over the period 1926-1984 indicating that the observed expected return on a security is related to its risk by the following equation:

$$K = .0829 + .0520 \beta$$

Given that the risk-free rate over the estimation period was approximately 6 percent, this relationship implies that the intercept of the risk-return relationship is higher than the 6 percent risk-free rate, contrary to the CAPM's prediction. Given that the average return on an average risk stock exceeded the risk-free rate by about 8.0 percent in that period, that is, the market risk premium ($R_M - R_F$) = 8 percent, the intercept of the observed relationship between return and beta exceeds the risk-free rate by about 2 percent, suggesting an alpha factor of 2 percent.

Most of the empirical studies cited in the above table utilize raw betas rather than Value Line adjusted betas because the latter were not available over most of the time periods covered in these studies. A study of the relationship between return and adjusted beta is reported on Table 6-7 in Ibbotson Associates Valuation Yearbook 2001. If we exclude the portfolio of very small cap stocks from the relationship due to significant size effects, the relationship between the arithmetic mean return and beta for the remaining portfolios is flatter than predicted and the intercept slightly higher than predicted by the CAPM, as shown on the graph below. It is noteworthy that the Ibbotson study relies on adjusted betas as stated on page 95 of the aforementioned study.

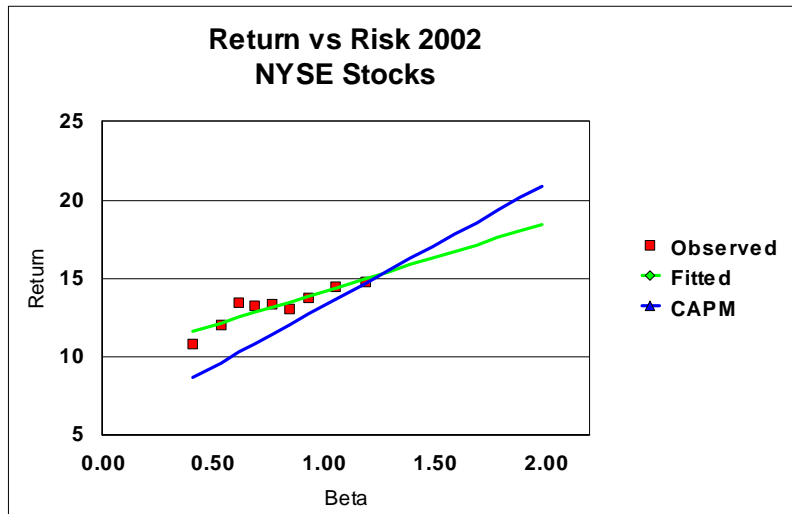
CAPM vs ECAPM



Another study by Morin in May 2002 provides empirical support for the ECAPM. All the stocks covered in the Value Line Investment Survey for Windows for which betas and returns data were available were retained for analysis. There were nearly 2000 such stocks. The expected return was measured as the total shareholder return (“TSR”) reported by Value Line over the past ten years. The Value Line adjusted beta was also retrieved from the same data base. The nearly 2000 companies for which all data were available were ranked in ascending order of beta, from lowest to highest. In order to palliate measurement error, the nearly 2000 securities were grouped into ten portfolios of approximately 180 securities for each portfolio. The average returns and betas for each portfolio were as follows:

Portfolio #	Beta	Return
portfolio 1	0.41	10.87
portfolio 2	0.54	12.02
portfolio 3	0.62	13.50
portfolio 4	0.69	13.30
portfolio 5	0.77	13.39
portfolio 6	0.85	13.07
portfolio 7	0.94	13.75
portfolio 8	1.06	14.53
portfolio 9	1.19	14.78
portfolio 10	1.48	20.78

It is clear from the graph below that the observed relationship between DCF returns and Value Line adjusted betas is flatter than that predicted by the plain vanilla CAPM. The observed intercept is higher than the prevailing risk-free rate of 5.7 percent while the slope is less than equal to the market risk premium of 7.7 percent predicted by the plain vanilla CAPM for that period.



In an article published in Financial Management, Harris, Marston, Mishra, and O’Brien (“HMMO”) estimate ex ante expected returns for S&P 500 companies over the period 1983-1998¹. HMMO measure the expected rate of return (cost of equity) of each dividend-paying stock in the S&P 500 for each month from January 1983 to August 1998 by using the constant growth DCF model. They then investigate the relation between the risk premium (expected return over the 20-year U.S. Treasury Bond yield) estimates for each month to equity betas as of that same month (5-year raw betas).

The table below, drawn from HMMO Table 4, displays the average estimate prospective risk premium (Column 2) by industry and the corresponding beta estimate for that industry, both in raw form (Column 3) and adjusted form (Column 4). The latter were calculated with the traditional Value Line – Merrill Lynch – Bloomberg adjustment methodology by giving 1/3 weight of to a beta estimate of 1.00 and 2/3 weight to the raw beta estimate.

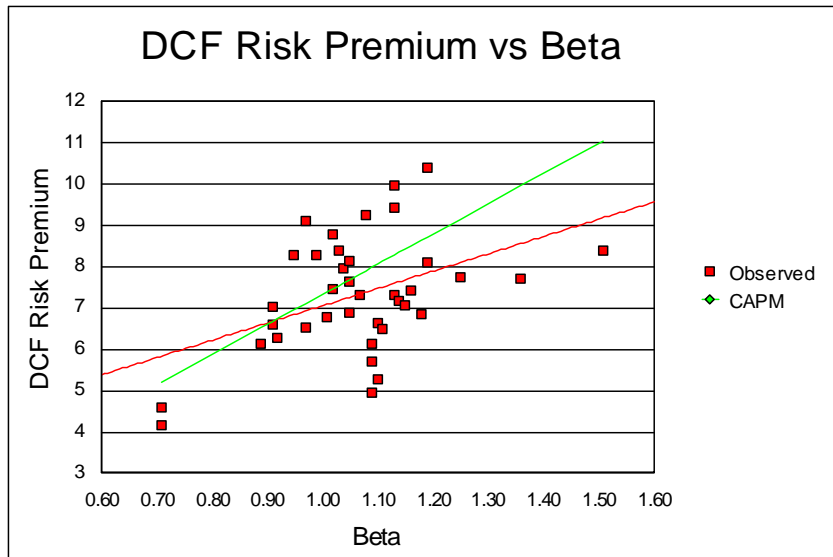
Table A-1 Risk Premium and Beta Estimates by Industry

Industry	DCF Risk Premium	Raw Industry Beta	Adjusted Industry Beta
(1)	(2)	(3)	(4)
1 Aero	6.63	1.15	1.10
2 Autos	5.29	1.15	1.10
3 Banks	7.16	1.21	1.14

¹ Harris, R. S., Marston, F. C., Mishra, D. R., and O’Brien, T. J., “Ex Ante Cost of Equity Estimates of S&P 500 Firms: The Choice Between Global and Domestic CAPM,” Financial Management, Autumn 2003, pp. 51-66.

4	Beer	6.60	0.87	0.91
5	BldMat	6.84	1.27	1.18
6	Books	7.64	1.07	1.05
7	Boxes	8.39	1.04	1.03
8	BusSv	8.15	1.07	1.05
9	Chems	6.49	1.16	1.11
10	Chips	8.11	1.28	1.19
11	Clths	7.74	1.37	1.25
12	Cnstr	7.70	1.54	1.36
13	Comps	9.42	1.19	1.13
14	Drugs	8.29	0.99	0.99
15	ElcEq	6.89	1.08	1.05
16	Energy	6.29	0.88	0.92
17	Fin	8.38	1.76	1.51
18	Food	7.02	0.86	0.91
19	Fun	9.98	1.19	1.13
20	Gold	4.59	0.57	0.71
21	Hlth	10.40	1.29	1.19
22	Hsld	6.77	1.02	1.01
23	Insur	7.46	1.03	1.02
24	LabEq	7.31	1.10	1.07
25	Mach	7.32	1.20	1.13
26	Meals	7.98	1.06	1.04
27	MedEq	8.80	1.03	1.02
28	Pap	6.14	1.13	1.09
29	PerSv	9.12	0.95	0.97
30	Retail	9.27	1.12	1.08
31	Rubber	7.06	1.22	1.15
32	Ships	1.95	0.95	0.97
33	Stee	4.96	1.13	1.09
34	Tele	6.12	0.83	0.89
35	Toys	7.42	1.24	1.16
36	Trans	5.70	1.14	1.09
37	Txtls	6.52	0.95	0.97
38	Util	4.15	0.57	0.71
39	Whlsl	8.29	0.92	0.95
	MEAN	7.19		

The observed statistical relationship between expected return and **adjusted beta** is shown in the graph below along with the CAPM prediction:



If the plain vanilla version of the CAPM is correct, then the intercept of the graph should be zero, recalling that the vertical axis represents returns in excess of the risk-free rate. Instead, the observed intercept is approximately 2 percent, that is approximately equal to 25 percent of the expected market risk premium of 7.2 percent shown at the bottom of Column 2 over the 1983-1998 period, as predicted by the ECAPM. The same is true for the slope of the graph. If the plain vanilla version of the CAPM is correct, then the slope of the relationship should equal the market risk premium of 7.2 percent. Instead, the observed slope of close to 5 percent is approximately equal to 75 percent of the expected market risk premium of 7.2 percent, as predicted by the ECAPM.

In short, the HMMO empirical findings are quite consistent with the predictions of the ECAPM.

Practical Implementation of the ECAPM

The empirical evidence reviewed above suggests that the expected return on a security is related to its risk by the following relationship:

$$K = R_F + \alpha + \beta (MRP - \alpha) \tag{5}$$

or, alternatively by the following equivalent relationship:

$$K = R_F + a \text{ MRP} + (1-a) \beta \text{ MRP} \quad (6)$$

The empirical findings support values of α from approximately 2 percent to 7 percent. If one is using the short-term U.S. Treasury Bills yield as a proxy for the risk-free rate, and given that utility stocks have lower than average betas, an alpha in the lower range of the empirical findings, 2 percent - 3 percent is reasonable, albeit conservative.

Using the long-term U.S. Treasury yield as a proxy for the risk-free rate, a lower alpha adjustment is indicated. This is because the use of the long-term U.S. Treasury yield as a proxy for the risk-free rate partially incorporates the desired effect of using the ECAPM². An alpha in the range of 1 percent - 2 percent is therefore reasonable.

To illustrate, consider a utility with a beta of 0.80. The risk-free rate is 5 percent, the MRP is 7 percent, and the alpha factor is 2 percent. The cost of capital is determined as follows:

$$\begin{aligned} K &= R_F + \alpha + \beta (\text{MRP} - \alpha) \\ K &= 5\% + 2\% + 0.80(7\% - 2\%) \\ &= 11\% \end{aligned}$$

A practical alternative is to rely on the second variation of the ECAPM:

$$K = R_F + a \text{ MRP} + (1-a) \beta \text{ MRP}$$

With an alpha of 2 percent, a MRP in the 6 percent - 8 percent range, the ‘a’ coefficient is 0.25, and the ECAPM becomes³:

² The Security Market Line (SML) using the long-term risk-free rate has a higher intercept and a flatter slope than the SML using the short-term risk-free rate

³ Recall that alpha equals ‘a’ times MRP, that is, $\alpha = a \text{ MRP}$, and therefore $a = \alpha / \text{MRP}$. If alpha is 2 percent, then $a = 0.25$

$$K = R_F + 0.25 \text{ MRP} + 0.75 \beta \text{ MRP}$$

Returning to the numerical example, the utility's cost of capital is:

$$\begin{aligned} K &= 5\% + 0.25 \times 7\% + 0.75 \times 0.80 \times 7\% \\ &= 11\% \end{aligned}$$

For reasonable values of beta and the MRP, both renditions of the ECAPM produce results that are virtually identical⁴.

⁴ In the Morin (1994) study, the value of "a" was actually derived by systematically varying the constant "a" in equation 6 from 0 to 1 in steps of 0.05 and choosing that value of 'a' that minimized the mean square error between the observed relationship between return and beta:

$$K = 0.0829 + .0520 \beta$$

The value of a that best explained the observed relationship was 0.25.

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APPENDIX B

FLOTATION COST ALLOWANCE

To obtain the final cost of equity financing from the investors' expected rate of return, it is necessary to make allowance for underpricing, which is the sum of market pressure, costs of flotation, and underwriting fees associated with new issues. Allowance for market pressure should be made because large blocks of new stock may cause significant pressure on market prices even in stable markets. Allowance must also be made for company costs of flotation (including such items as printing, legal and accounting expenses) and for underwriting fees.

1. MAGNITUDE OF FLOTATION COSTS

According to empirical studies, underwriting costs and expenses average at least 4% of gross proceeds for utility stock offerings in the U.S. (See Logue & Jarrow: "Negotiations vs. Competitive Bidding in the Sale of Securities by Public Utilities", Financial Management, Fall 1978.) A study of 641 common stock issues by 95 electric utilities identified a flotation cost allowance of 5.0%. (See Borum & Malley: "Total Flotation Cost for Electric Company Equity Issues", Public Utilities Fortnightly, Feb. 20, 1986.)

Empirical studies suggest an allowance of 1% for market pressure in U.S. studies. Logue and Jarrow found that the absolute magnitude of the relative price decline due to market pressure was less than 1.5%. Bowyer and Yawitz examined 278 public utility stock issues and found an average market pressure of 0.72%. (See Bowyer & Yawitz, "The Effect of New Equity Issues on Utility Stock Prices", Public Utilities Fortnightly, May 22, 1980.)

Eckbo & Masulis ("Rights vs. Underwritten Stock Offerings: An Empirical Analysis", University of British Columbia, Working Paper No. 1208, Sept., 1987) found an average flotation cost of 4.175% for utility common stock offerings. Moreover, flotation costs increased progressively for

smaller size issues. They also found that the relative price decline due to market pressure in the days surrounding the announcement amounted to slightly more than 1.5%. In a classic and monumental study published in the prestigious Journal of Financial Economics by a prominent scholar, a market pressure effect of 3.14% for industrial stock issues and 0.75% for utility common stock issues was found (see Smith, C.W., "Investment Banking and the Capital Acquisition Process," Journal of Financial Economics 15, 1986). Other studies of market pressure are reported in Logue ("On the Pricing of Unseasoned Equity Offerings, Journal of Financial and Quantitative Analysis, Jan. 1973), Pettway ("The Effects of New Equity Sales Upon Utility Share Prices," Public Utilities Fortnightly, May 10 1984), and Reilly and Hatfield ("Investor Experience with New Stock Issues," Financial Analysts' Journal, Sept.- Oct. 1969). In the Pettway study, the market pressure effect for a sample of 368 public utility equity sales was in the range of 2% to 3%. Adding the direct and indirect effects of utility common stock issues, the indicated total flotation cost allowance is above 5.0%, corroborating the results of earlier studies.

As shown in the table below, a comprehensive empirical study by Lee, Lochhead, Ritter, and Zhao, "The Costs of Raising Capital," Journal of Financial Research, Vol. XIX, NO. 1, Spring 1996, shows average direct flotation costs for equity offerings of 3.5% - 5% for stock issues between \$60 and \$500 million. Allowing for market pressure costs raises the flotation cost allowance to well above 5%.

FLOTATION COSTS: RAISING EXTERNAL CAPITAL

(Percent of Total Capital Raised)

Amount Raised in \$ Millions	Average Flotation Cost: Common Stock	Average Flotation Cost: New Debt
\$ 2 - 9.99	13.28%	4.39%
10 - 19.99	8.72	2.76
20 - 39.99	6.93	2.42
40 - 59.99	5.87	1.32
60 - 79.99	5.18	2.34
80 - 99.99	4.73	2.16
100 - 199.99	4.22	2.31
200 - 499.99	3.47	2.19
500 and Up	3.15	1.64

Note: Flotation costs for IPOs are about 17 percent of the value of common stock issued if the amount raised is less than \$10 million and about 6 percent if more than \$500 million is raised. Flotation costs are somewhat lower for utilities than others.

Source: Lee, Inmoo, Scott Lochhead, Jay Ritter, and Quanshui Zhao, "The Costs of Raising Capital," *The Journal of Financial Research*, Spring 1996.

Therefore, based on empirical studies, total flotation costs including market pressure amount to approximately 5% of gross proceeds. I have therefore assumed a 5% gross total flotation cost allowance in my cost of capital analyses.

2. APPLICATION OF THE FLOTATION COST ADJUSTMENT

The section below shows: 1) why it is necessary to apply an allowance of 5% to the dividend

yield component of equity cost by dividing that yield by 0.95 (100% - 5%) to obtain the fair return on equity capital, and 2) why the flotation adjustment is permanently required to avoid confiscation even if no further stock issues are contemplated. Flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years.

Flotation costs are just as real as costs incurred to build utility plant. Fair regulatory treatment absolutely must permit the recovery of these costs. An analogy with bond issues is useful to understand the treatment of flotation costs in the case of common stocks.

In the case of a bond issue, flotation costs are not expensed but are rather amortized over the life of the bond, and the annual amortization charge is embedded in the cost of service. This is analogous to the process of depreciation, which allows the recovery of funds invested in utility plant. The recovery of bond flotation expense continues year after year, irrespective of whether the company issues new debt capital in the future, until recovery is complete. In the case of common stock that has no finite life, flotation costs are not amortized. Therefore, the recovery of flotation cost requires an upward adjustment to the allowed return on equity. Roger A. Morin, Regulatory Finance, Public Utilities Reports Inc., Arlington, Va., 1994, provides numerical illustrations that show that even if a utility does not contemplate any additional common stock issues, a flotation cost adjustment is still permanently required. Examples there also demonstrate that the allowance applies to retained earnings as well as to the original capital.

From the standard DCF model, the investor's required return on equity capital is expressed as:

$$K = D_1/P_0 + g$$

If P_0 is regarded as the proceeds per share actually received by the company from which dividends and earnings will be generated, that is, P_0 equals B_0 , the book value per share, then the company's required return is:

$$r = D_1/B_0 + g$$

Denoting the percentage flotation costs 'f', proceeds per share B_0 are related to market price P_0 as follows:

$$P - fP = B_0$$

$$P(1 - f) = B_0$$

Substituting the latter equation into the above expression for return on equity, we obtain:

$$r = D_1/P(1-f) + g$$

that is, the utility's required return adjusted for underpricing. For flotation costs of 5%, dividing the expected dividend yield by 0.95 will produce the adjusted cost of equity capital. For a dividend yield of 6% for example, the magnitude of the adjustment is 32 basis points: $.06/.95 = .0632$.

In deriving DCF estimates of fair return on equity, it is therefore necessary to apply a conservative after-tax allowance of 5% to the dividend yield component of equity cost.

Even if no further stock issues are contemplated, the flotation adjustment is still permanently required to keep shareholders whole. Flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years, even if no future financing is contemplated. This is demonstrated by the numerical example contained in pages 7-9 of this Appendix. Moreover, even if the stock price, hence the DCF estimate of equity return, fully reflected the lack of permanent allowance, the company always nets less than the market price. Only the net proceeds from an equity issue are used to add to the rate base on which the investor earns. A permanent allowance for flotation costs must be authorized in order to insure that in each year the investor earns the required return on the total amount of capital actually supplied.

The example shown on pages 7-9 shows the flotation cost adjustment process using illustrative, yet realistic, market data. The assumptions used in the computation are shown on page 7. The stock is selling in the market for \$25, investors expect the firm to pay a dividend of \$2.25 that will grow at a rate of 5% thereafter. The traditional DCF cost of equity is thus $k = D/P + g = 2.25/25 + .05 = 14\%$. The firm sells one share stock, incurring a flotation cost of 5%. The traditional DCF cost of equity adjusted for flotation cost is thus $ROE = D/P(1-f) + g = .09/.95 + .05 = 14.47\%$.

The initial book value (rate base) is the net proceeds from the stock issue, which are \$23.75, that is, the market price less the 5% flotation costs. The example demonstrates that only if the company is allowed to earn 14.47% on rate base will investors earn their cost of equity of 14%. On page 8, Column 1 shows the initial common stock account, Column 2 the cumulative retained earnings balance, starting

at zero, and steadily increasing from the retention of earnings. Total equity in Column 3 is the sum of common stock capital and retained earnings. The stock price in Column 4 is obtained from the seminal DCF formula: $D_1/(k - g)$. Earnings per share in Column 6 are simply the allowed return of 14.47% times the total common equity base. Dividends start at \$2.25 and grow at 5% thereafter, which they must do if investors are to earn a 14% return. The dividend payout ratio remains constant, as per the assumption of the DCF model. All quantities, stock price, book value, earnings, and dividends grow at a 5% rate, as shown at the bottom of the relevant columns. Only if the company is allowed to earn 14.47% on equity do investors earn 14%. For example, if the company is allowed only 14%, the stock price drops from \$26.25 to \$26.13 in the second year, inflicting a loss on shareholders. This is shown on page 9. The growth rate drops from 5% to 4.53%. Thus, investors only earn $9\% + 4.53\% = 13.53\%$ on their investment. It is noteworthy that the adjustment is always required each and every year, whether or not new stock issues are sold in the future, and that the allowed return on equity must be earned on total equity, including retained earnings, for investors to earn the cost of equity.

ASSUMPTIONS:

ISSUE PRICE = \$25.00
FLOTATION COST = 5.00%
DIVIDEND YIELD = 9.00%
GROWTH = 5.00%

EQUITY RETURN = **14.00%**
(D/P + g)
ALLOWED RETURN ON EQUITY = **14.47%**
(D/P(1-f) + g)

Yr	COMMON STOCK (1)	RETAINED EARNINGS (2)	TOTAL EQUITY (3)	STOCK PRICE (4)	MARKET	EPS (6)	DPS (7)	PAYOUT (8)
					/ BOOK RATIO (5)			
1	\$23.75	\$0.000	\$23.750	\$25.000	1.0526	\$3.438	\$2.250	65.45%
2	\$23.75	\$1.188	\$24.938	\$26.250	1.0526	\$3.609	\$2.363	65.45%
3	\$23.75	\$2.434	\$26.184	\$27.563	1.0526	\$3.790	\$2.481	65.45%
4	\$23.75	\$3.744	\$27.494	\$28.941	1.0526	\$3.979	\$2.605	65.45%
5	\$23.75	\$5.118	\$28.868	\$30.388	1.0526	\$4.178	\$2.735	65.45%
6	\$23.75	\$6.562	\$30.312	\$31.907	1.0526	\$4.387	\$2.872	65.45%
7	\$23.75	\$8.077	\$31.827	\$33.502	1.0526	\$4.607	\$3.015	65.45%
8	\$23.75	\$9.669	\$33.419	\$35.178	1.0526	\$4.837	\$3.166	65.45%
9	\$23.75	\$11.340	\$35.090	\$36.936	1.0526	\$5.079	\$3.324	65.45%
10	\$23.75	\$13.094	\$36.844	\$38.783	1.0526	\$5.333	\$3.490	65.45%
				5.00%	5.00%	5.00%		5.00%

Yr	COMMON	RETAINED	TOTAL	STOCK	MARKET/ BOOK	EPS	DPS	PAYOUT
	STOCK (1)	EARNINGS (2)	EQUITY (3)	PRICE (4)	RATIO (5)	(6)	(7)	(8)
1	\$23.75	\$0.000	\$23.750	\$25.000	1.0526	\$3.325	\$2.250	67.67%
2	\$23.75	\$1.075	\$24.825	\$26.132	1.0526	\$3.476	\$2.352	67.67%
3	\$23.75	\$2.199	\$25.949	\$27.314	1.0526	\$3.633	\$2.458	67.67%
4	\$23.75	\$3.373	\$27.123	\$28.551	1.0526	\$3.797	\$2.570	67.67%
5	\$23.75	\$4.601	\$28.351	\$29.843	1.0526	\$3.969	\$2.686	67.67%
6	\$23.75	\$5.884	\$29.634	\$31.194	1.0526	\$4.149	\$2.807	67.67%
7	\$23.75	\$7.225	\$30.975	\$32.606	1.0526	\$4.337	\$2.935	67.67%
8	\$23.75	\$8.627	\$32.377	\$34.082	1.0526	\$4.533	\$3.067	67.67%
9	\$23.75	\$10.093	\$33.843	\$35.624	1.0526	\$4.738	\$3.206	67.67%
10	\$23.75	\$11.625	\$35.375	\$37.237	1.0526	\$4.952	\$3.351	67.67%
			4.53%	4.53%			4.53%	4.53%