BEFORE THE PUBLIC SERVICE COMMISSION

OF MARYLAND

IN THE MATTER OF THE		
APPLICATION OF BALTIMORE GAS	)	
AND ELECTRIC COMPANY FOR	)	Case No. 9888
AUTHORITY TO INCREASE	)	
EXISTING RATES AND CHARGES	)	
FOR ELECTRIC SERVICE	)	

DIRECT TESTIMONY AND ATTACHMENTS

OF DANIEL CASSARA

ON BEHALF OF

THE MARYLAND OFFICE OF PEOPLE'S COUNSEL

SEPTEMBER 22, 2026

TABLE OF CONTENTS

LIST OF ATTACHMENTS

1. Introduction & Purpose of Testimony

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

A. My name is Daniel Cassara. I am a Senior Consultant at Current Energy Group LLC (CEG). My business address is 4764 E Sunrise Drive #508, Tucson, Arizona 85718.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Maryland Office of People's Counsel.

Q. Have you previously testified in proceedings before the Maryland Public Service Commission?

A. No.

Q. Have you testified in other regulatory jurisdictions before?

A. Yes. I have testified in North Carolina in the most recent rate case proceedings for Duke Energy Carolinas and Duke Energy Progress.

Q. Please summarize your professional and educational background.

A. I have a Bachelor of Arts in Economics from the University of Chicago and a Master of Public Administration in Environmental Science & Policy from Columbia University.

After completing my undergraduate studies, I worked for five years at Dimensional Fund Advisors, a prominent investment manager with more than $1 trillion in assets under management. At Dimensional I worked directly with some of the largest and most sophisticated investors in the country, supporting key relationships with analysis on investment products and portfolio construction. I completed the requirements for the Certified Financial Professional® designation, though I allowed my certification to lapse since leaving the investment industry. Since joining Current Energy Group in 2025, I have supported testimony regarding return on equity ("ROE") and capital structure in several rate case proceedings, have provided testimony on ROE in two North Carolina rate case proceedings, and have co-authored a forthcoming whitepaper analyzing the use of financial models to estimate cost of equity in rate cases. My resume is attached as Attachment DMC-1.

Q. What is the purpose of your direct testimony?

A. The purpose of this testimony is to assist the Commission in finding an appropriate return on equity ("ROE") and capital structure for Baltimore Gas and Electric Company ("BGE," or "company").

Q. What documents do you rely upon for your analysis, findings, and recommendations?

A. My analysis relies primarily upon public and private data, analysis, and reports available from the largest asset managers, capital advisors, and financial institutions in the United States. This information is combined with the testimonies and exhibits filed by the company.

2. Summary & Recommendations

Q. Please describe the company's proposed capital structure, return on equity, return on debt, and overall rate of return.

A. The company proposes an overall rate of return ("ROR") of 7.68 percent, based on the following capital structure and cost of capital for equity, long-term debt, and short-term debt:

Table 1: BGE's Proposed Capital Structure and Rate of Return[1]

Capital Type	Ratio	Capital Cost	Weighted Cost
Long-term debt	48.0%	4.72%	2.27%
Equity	52.0%	10.40%	5.41%
Total	**100%**	**-**	**7.68%**

Q. Please summarize the cost of equity results that company produces.

A. Company witness Adrien McKenzie uses the Discounted Cash Flow ("DCF"), Capital Asset Pricing Model ("CAPM"), Empirical Capital Asset Pricing Model ("ECAPM"), a Utility Risk Premium model, and the Expected Earnings Approach to estimate a cost of equity for a group of companies that proxy BGE. His analyses produce mean estimates of 10.2 percent (DCF), 10.7 percent (CAPM), 11.2 percent (ECAPM), 10.5 percent (Utility Risk Premium), and 10.4 percent (Expected Earnings), for an overall average of 10.6 percent. The range that Mr. McKenzie develops from this set of analysis is from 9.9 percent to 10.9, and he

[1] Direct Testimony of Michael J. Cloyd ("Cloyd Direct") at 13.

recommends the Commission adopt a 10.4 percent ROE, the midpoint of the range, as BGE's ROE.[2]

Q. Please briefly describe your testimony and analysis.

A. To begin with, I considered the legal standards from *Hope* and *Bluefield* that specify a fair ROE for BGE should allow equity shareholders to earn a return similar to that being offered by similarly risky equity investments and that it should be sufficient to enable BGE to attract capital and remain financially stable. Next, I considered the research and analysis of professional investment managers and academics, along with current capital market conditions. Unbiased, highly experienced investors currently expect the overall US market to return 8 percent or less over the coming years. Because utilities' stocks are less risky than the overall market, 8 percent is the ceiling on a reasonable estimate of BGE's cost of equity. Finally, I estimated BGE's cost of equity using the Capital Asset Pricing Model and a Multi-Stage Discounted Cash Flow model. The results from these models are summarized in Table 2 below.

[2] Direct Testimony of Adrien M. McKenzie ("McKenzie Direct") at 3; *see also* BGE Exhibit AMM-2.

Table 2: Summary of Cost of Equity Model Results

Cost of Equity Model	**Proxy Group**	**Exelon Corporation**
Capital Asset Pricing Model	**6.81%**	**6.35%**
Multi-Stage DCF		
Growth = GDP	7.82%	8.04%
Growth = Utility EPS	7.57%	7.79%
Average	**7.70%**	**7.91%**
Mean Result	7.26%	7.13%
ROE Recommendation	**7.30%**	

Q. Please summarize your recommendations to the Commission.

A. I recommend the following:

1. The Commission should approve an ROE for BGE of 7.3 percent. I recommend an ROE of 7.3 percent based on the results of my CAPM and DCF models, the capital market assumptions published by investment managers, research from the academic community, and current market conditions.
2. The Commission should accept the Company's proposed cost of debt of 4.72 percent and proposed equity ratio of 52 percent, in line with the equity ratio that it authorized in prior cases.
3. The Commission should give little weight to the results from Mr. McKenzie's models and should reject the framework that BGE used to develop its ROE proposal. BGE's framework has the following three errors which should be corrected:

(a) BGE conflates *return on equity*, which represents the regulatory decision-making of commissions, with the *cost of equity*, which represents price discovery in competitive markets. Conflating the two concepts leads to inaccurate analysis and contributes to an unreasonably high ROE recommendation.

(b) BGE's analysis fails to distinguish between the return BGE earns as a company, which is an accounting measure, and the return BGE shareholders earn, which is a market measure. Understanding the difference between the two measures and correctly relying on the market return shareholders earn is necessary to properly evaluate how the returns offered to BGE's investors compare to those offered to investors in other similar utilities.

(c) The inputs and assumptions BGE uses to estimate the cost of equity are not suitably grounded in asset pricing theory and are disconnected from the estimates of academic researchers and professional investment managers. For these reasons, BGE's analysis does not reflect the best practices of the investment industry, and its requested ROE is a clear outlier from the expectations of equity market investors and academics.

4. Based on my above recommendations (1) through (3), the Commission should set BGE's overall rate of return at 6.07 percent as shown in Table 3 below.
5. The Commission should reject BGE's proposed Operating Income Adjustment 25 because the adjustment unreasonably increases the company's equity ratio and overall ROR for non-EmPOWER assets, raising its revenue requirement by $6.96 million and largely eliminating the impact of Operating Income Adjustment 24, which was made to comply with statutory mandates in House Bill 864.

Table 3: Recommended Capital Structure and Cost of Capital for BGE

Capital Type	Ratio	Capital Cost	Weighted Cost
Equity	52.0%	7.30%	3.80%
Long-term Debt	48.0%	4.72%	2.27%
Total	**100%**	**-**	**6.07%**

Q. How would customers' bills be impacted should the Commission adopt your recommended 7.3 percent ROE?

A. 25 percent of the rate increase that BGE has proposed in this proceeding would be used to support higher profits for the company. Adopting a 7.3 percent ROE would lower rates relative to the company's proposal by $134 million annually. Of that, residential customers would save nearly $82 million in rates each year, or roughly $110 per customer.

Q. If you do not address statements made by BGE in its testimony, does that signal that you agree with such statements?

A. No. To the extent that I have not addressed statements made in testimony filed by BGE, it does not constitute agreement with such testimony.

Q. How is the rest of your testimony organized?

A. Sections 2 and 3 summarize the Company's proposal for rate of return and my recommendations to the Commission. The remainder of my testimony is broadly split into two parts.

The first part, from Sections 3 to 6, reviews asset pricing theory and uses market data to estimate a reasonable ceiling for BGE's ROE. Specifically, Section 3 discusses the equivalence between cost of equity, investors required return on equity, and the expected market return on equity, as well as the distinction between utility accounting or "book" returns and shareholder or "market" returns; Section 4 addresses the regulatory standards for a just and reasonable ROE; Section 5 examines historic data to contextualize return forecasts and discusses how valuation ratios such as Price-to-Book are informative about the relationship between COE and ROE; Section 6 reviews evidence from academics and investors about current expected market returns.

Part two of my testimony, from Sections 7 to 11, evaluates a fair return for BGE and the impact ROE has on BGE's ratepayers. Specifically, Section 7 summarizes the COE models I implemented; Section 8 estimates the savings to ratepayers from lowering BGE's ROE; Section 9 discusses the flaws in BGE's analysis, including the claim that reducing the company's ROE could actually increase the total cost of service borne by consumers; Section 10 evaluates BGE's proposed capital structure and cost of debt to develop an overall rate of return ("ROR"); and Section 11 summarizes my recommendations to Commission.

3. Principles for Evaluating the Cost of Equity

Q. What is the purpose of this section of your testimony?

A. This section of my testimony aims to accomplish three things. First, I define key terms relevant to determining a just and reasonable ROE for BGE. There are multiple types of "return" that are frequently discussed in ratemaking proceedings, and many witnesses use the term "return" to describe different measures interchangeably; confusion about which return is being referred to can lead to misleading analysis. Second, I discuss which of these returns is relevant to determining a utility's cost of equity. Evaluating the correct return is critical to measuring the cost a utility faces. Finally, I discuss the empirical strategies for estimating the cost of equity.

i. The terms cost of equity, expected return on equity, and required return on equity are synonymous with each other, and are all based on the opportunity cost investors face.

Q. What is the cost of capital?

A. The cost of capital is the return investors require in exchange for providing capital. Different forms of capital—e.g., equity and debt capital—will have different costs. The overall cost of capital is the weighted average cost of each form of capital the utility uses to finance operations and capital expenditures.

Q. Explain how you use the terms cost of equity, the expected return on equity, and investors' required return on equity.

A. The cost of equity is determined by the collective actions of buyers and sellers and in the stock market. Each buyer and seller has their own views and preferences with respect to the expected future profits and risks a utility faces, and the market's aggregate supply and demand for a stock sets its cost of equity. Investors are willing to provide a maximum amount of capital given the return they expect to receive. The difference between the capital provided versus the proceeds the investors expect to receive is the "cost" from the utility's perspective, and the "expected return" from the investor's perspective. In other words, the two terms are equivalent.

In competitive markets (e.g., US stock markets) a utility can attract capital from the investor(s) requiring the lowest return, who thus provide capital for the lowest price. If a stock's expected return is below what investors require, they will sell the stock, reducing its price and increasing the expected return until it matches their requirement. This process also runs in reverse.[3]

For this reason, the "cost of equity", "expected return", and "required return" are effectively all the same. Throughout my testimony, I refer to all three terms

[3] *See, e.g.,* Z. Bodie, A. Kane & A. Marcus, *Investments* (12th ed., McGraw-Hill Education, 2021) at 10 ("if any particular asset offered higher expected returns without imposing extra risk, investors would rush to buy it, with the result that its price would be driven up. Individuals considering investing in the asset at the now-higher price will find the investment less attractive. The price will rise until the expected return is no more than commensurate with risk"); *see also*, R.A. Morin, *New Regulatory Finance*, Public Utilities Reports, Inc. (2006) at 22 ("Cost of capital is synonymous with required return.").

synonymously, depending on the context. For example, when I refer to research from the regulatory arena, the use of "required returns" is more common, whereas professional investors typically discuss "expected returns." It is important to understand that although different stakeholders may use different terminology, they are discussing the same fundamental concepts, and as such, their perspectives speak directly to each other.

Q. Please explain the difference between "expected" and "realized" returns, and the relevance of the distinction to utility ratemaking.

A. Because future outcomes are inherently uncertain, executives and investors must make decisions about how to deploy capital based on expectations for the future. The return that is anticipated before-the-fact is the "expected return," whereas the return that is actually generated is the "realized return." Realized returns can differ from expected returns, but the divergence does not retroactively change expected returns.

The distinction between expected and realized returns can be applied to any type of return (e.g., a project-level return or a stock price return) or over any time frame, but is most commonly used to refer to an investor's expected return on equity or debt investments. Throughout my testimony, I use the phrase "expected return" to refer to the expected return on equity investments, and "expected return on book equity" to refer to a utility's anticipated accounting return on the net book value of its assets.

Q. Please explain how opportunity cost is related to the three synonymous terms of cost of equity, expected returns, and required returns.

A. Opportunity cost is the return an investor could expect to receive from investing in other enterprises with similar levels of risk. Opportunity cost is thus what determines the cost of capital: if an investor can expect to receive a higher rate of return from another security with commensurate risk, she will sell those investments offering lower returns and replace them with those offering higher returns.[4]

Opportunity cost is a forward-looking measure: investors providing capital today are concerned with returns for tomorrow, not what returns would have been had they provided capital yesterday.[5] In other words, opportunity cost is based on expected returns, not realized returns. The expected return to an investor for providing capital to the utility must be equal to the expected return for providing capital to other enterprises with equivalent risks, or the utility will not be able to access capital.

[4] Morin (2006) at 21-22.

[5] This is not to imply that past returns are not useful information. As I will discuss in greater detail in Section 5, past returns are useful for forming a reasonable expectation for the future, but past returns alone do not tell the full story.

Q. Are there multiple uses for the phrase "return on equity" in accounting, finance, and utility ratemaking?

A. Yes. The *authorized return on equity* is a utility ratemaking concept. It is set during a rate case and represents the revenue a utility may include in rates to provide a reasonable opportunity for its shareholders to earn a return on equity investments. The *realized return on equity* is the utility's book return.

Q. How are a utility's *authorized* return on equity and *realized* return on equity related?

A. A utility's *authorized* return on equity and *realized* return on equity are distinct, but interrelated concepts. As noted above, the *authorized* return on equity is a component of a utility's revenue requirement. A utility's revenue requirement directly influences the net income the utility can earn, which makes it a determining factor in the utility's *realized* return on equity.

For clarity, throughout the remainder of my testimony, I will refer to the concept of *realized* return on equity as the book return, and the concept of an *authorized* return on equity as the authorized ROE or simply ROE.

ii. Understanding the distinction between the book return earned by BGE and the market return earned by its equity investors is crucial to setting a just and reasonable ROE.

Q. You've shown that cost of equity, expected returns, and required returns are equivalent to each other. How are "returns" measured?

A. A utility generates two different types of returns: (1) an accounting, or *book return* and (2) a *market return* for equity shareholders of its stock.

Q. Please explain what is meant by the accounting, or book return.

A. Book returns are measured by dividing the net income to shareholders by the value of shareholder equity. Book returns are an accounting measure of the utility's realized return on equity. Effectively, the book return is the return to the utility itself.

Q. Please explain what is meant by the market return.

A. Market returns are the total return to a shareholder, defined as the dividends received plus the capital appreciation (increase) in the stock price. When investors evaluate the prospective market returns of a potential investment, they are evaluating the investment's expected return.

Q. Why does the distinction between book returns and market returns matter?

A. The Supreme Court directs regulators to set an ROE such that "[t]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks."[6] This is known as the "comparable earnings standard," which I will discuss in more detail in the following Section. For now, however, it is important to note that the Supreme Court simply states "the return to the equity owner," but does not specify how to measure said return. Thus, to properly evaluate the Court's guidance on a just and reasonable ROE, it is necessary to understand the distinction between different types of returns.

[6] *Bluefield Waterworks & Improvement Co. v. Public Service Commission*, 262 U.S. 679, 692-693 (1923).

Q. Do the rates customers pay to BGE support the company's book return, investors' market return, or both?

A. The rates that customers pay, which are determined in part by the ROE set by the Commission, directly increase company's book return. When the Commission authorizes a higher ROE, customers pay higher rates for each unit of BGE's rate base.

Q. Are there examples of the company's testimony confusing the two types of returns?

A. Yes. Mr. McKenzie oscillates between comparing investors' expectations for utilities' ROEs (book returns) and investors' expectations for equity returns (market returns). For example, the quote below comes from Mr. McKenzie's discussion on the Expected Earnings approach. In the *italicized text*, Mr. McKenzie references book returns, while in the <u>underlined text</u> he references market returns:

> Regulators do not set the returns that investors earn in the capital markets, which are a function of dividend payments and fluctuations in common stock prices, both of which are outside their control. Regulators can only establish *the allowed ROE, which is applied to the book value of a utility's investment in rate base, as determined from its accounting records.* This is analogous to *the expected earnings approach, which measures the return that investors expect the utility to earn on book value.* As a result, *the expected earnings approach provides a meaningful guide to ensure that the allowed ROE is similar to what other utilities of comparable risk will earn on invested capital*. This expected earnings test does not require theoretical models to indirectly infer investors' perceptions from stock prices or other market data. As long as the proxy companies are similar in risk, *their expected earned returns on invested capital* provide a direct benchmark for investors' opportunity costs that is independent of the limitations inherent in any theoretical model of investor behavior.[7]

While he acknowledges that regulators do not set the returns investors earn in the market—which are a function of the cost of equity—Mr. McKenzie attempts to directly link "the return that investors expect the utility to earn on book value" or the utility's book return, to "investors' opportunity costs," or their cost of equity. These are two different types of returns, and conflating the two is both incorrect and inappropriate.

Q. You state that book returns and market returns are different types of returns. Can you demonstrate that they do not equal to each other?

A. Yes, it is easy to show that book returns and market returns typically differ. For example, Exelon Corporation (Exelon), the publicly traded parent company of BGE, reported a book return on common equity of 9.94% in 2025,[8] while a

[7] McKenzie Direct at 59 (emphasis added).

[8] Annual Form 10-K, Exelon Corporation (Feb. 2026) at 120 https://investors.exeloncorp.com/node/41186/html. Exelon reported $2,768 million in net income

shareholder who held Exelon stock for the year had a market return of 20.5%.[9] Figure 1 below plots the book return on equity (y-axis) and the market return (x-axis) for each stock in Mr. McKenzie's proxy group and for the last ten calendar years. The R-squared, a statistical measure of how much change in one variable is explained by change in another variable, is 0.04 for the proxy group companies and 0.13 for Exelon. In other words, very little of the annual market return for the proxy group companies and for Exelon was explained by their book return over this 10 year period.

Figure 1: Stock Returns vs. Book Returns (2016-2025)[10]

available to common stockholders. Exelon had an average value of Total Common Equity of $27,859.5 million for the year. Thus, the return on common equity = $2,768 / $27,2859.5 = 9.94%.

[9] *Id.* at 34-35.

[10] S&P CapIQ for data; Analysis by author.

Figure 1 demonstrates that shareholders' market returns have not been strongly tied to the book return the studied utilities reported over the past decade, as indicated by the R-squared terms.

Figure 1 also shows that book returns have generally been between 7.8 percent and 11.4 percent (the 25th and 75th percentile for this dataset). These book returns are similar to the 9.64 percent average authorized ROE for electric during the same period, consistent with the expectation that authorized returns heavily influence a utility's net income.[11] Book returns have been similar to authorized ROEs over this period, but have not had much influence over market returns.

Q. Why do book returns and market returns typically differ?

A. The utility's opportunity to earn higher book returns is a function of the authorized ROE the Commission approves, with higher ROEs translating directly to higher rates for customers and to higher book returns for the company. The utility does not pay for the right to charge customers higher rates, the Commission simply authorizes higher rates. Shareholders, on the other hand, are not given the opportunity to buy shares at the book value of equity and must pay the market-determined stock price for a claim on the residual book earnings paid to investors. When authorized rates rise, expected book returns (and thus cash flow to investors) also rise. Investors buy the stock, pushing up its stock price. Existing shareholders reap an immediate gain, but expected market returns for new

[11] S&P RRA Rate Case Statistics (accessed September 3, 2026).

investors are the same as before a higher ROE was authorized; prices adjust to lower ROEs in the same manner.[12] This price-adjustment process is ultimately what explains why book returns do not translate into market returns.

Q. Is the cost of equity related to book returns or market returns?

A. The cost of equity a utility faces is related to the market returns investors expect to receive. Book returns are independent from the capital markets and shareholders do not earn the book return reported by a firm, thus the cost of equity is not directly based on a firm's expected book returns.

iii. The cost of equity is different from return on equity. Cost of equity must be estimated using financial models and is a function of risk.

Q. How is the cost of equity estimated?

A. The cost of equity cannot be observed directly and must be estimated using financial analyses, which may include the Capital Asset Pricing Model ("CAPM") and Discounted Cash Flow ("DCF") models. These models aim to estimate the expected return of a stock using information about market conditions, expected future returns for investors, and current prices.

[12] *See, e.g.,* Z. Bodie, A. Kane & A. Marcus, *Investments* (12th ed., McGraw-Hill Education, 2021) at 10 ("if any particular asset offered higher expected returns without imposing extra risk, investors would rush to buy it, with the result that its price would be driven up. Individuals considering investing in the asset at the now-higher price will find the investment less attractive. The price will rise until the expected return is no more than commensurate with risk.")

Q. Please explain the relationship between cost of equity and risk.

A. The relationship between cost of equity ("COE"), investor expectations, and risk is simple: investors are willing to accept a lower return on capital invested in securities that have a lower risk of yielding a financial loss.

Q. How do you measure risk?

A. There are two main metrics that investors use to measure a stock's risk: volatility and beta. Volatility, or standard deviation, measures the dispersion of a stock's market returns; higher volatility equates to larger price swings and uncertainty, and thus higher risk. Beta measures the correlation between a stock's return and that of a broad market index, usually the S&P 500. A beta higher than 1 corresponds to above average risk, while a beta lower than 1 corresponds to below average risk.

Q. Do all risks increase a utility's cost of equity?

A. No. Equity investors face two different types of risks: company-specific (or diversifiable) risk and market (also called systemic or non-diversifiable) risk. Rational investors diversify broadly across sectors and companies, which reduces their exposure to company-specific risk. For this reason, diversified investors do not need to be compensated for company-specific risks and are willing to pay higher prices for a given security than undiversified investors, who do bear company-specific risk. As a result, the price of the stock will be set by diversified investors, and the stock's expected return will only reflect exposure to market risk. The fact that investors diversify their risks is a crucial market reality that regulators must bear in mind when authorizing a utility's return on equity.

Q. How does the risk of investing in utility stocks compare to the risk of investing in non-utility stocks?

A. Utility stocks are less risky than non-utility stocks because utilities operate as a protected monopoly, which provides assurance that prudently incurred costs can be recovered through the rates the utility is allowed to charge. The assurance of cost recovery significantly reduces the risks that investors face. A utility's cost of equity reflects that reduction in risk. For example, Yahoo! Finance reports that the beta for Exelon Corporation, the parent company of BGE, is 0.39, whereas the betas for prominent companies across various industries such as Meta (1.24), Ford Motors (1.84), Nvidia (2.22), Bank of America (1.16), and Apple (1.09) are all above 1.[13] Later in my testimony I provide data showing that the beta for utilities in general has been persistently below 1, reflecting the fact that their equity is less risky than the equity for the average company in the market.

Q. Is there a difference between a utility's COE and its authorized ROE?

A. Yes. The COE and authorized ROE are frequently confused in utility regulatory proceedings, in part because utility experts often use the two terms interchangeably. However, COE and authorized ROE are different concepts. The authorized ROE is simply the return on equity that a Commission sets for a utility in a rate case, while the COE is the expected market return from the perspective of shareholders. When a utility commission authorizes a ROE higher than a utility's COE, it favors shareholders at the expense of consumers. Muddying the difference between the

[13] Yahoo! Finance betas as of August 2026; accessed September 15, 2026.

COE and ROE, therefore, is not simply a semantic concern. The Commission cannot uphold its obligation to establish just and reasonable rates unless it authorizes an ROE that aligns with the utility's *actual* COE. The confusion between *cost* of equity and *return* on equity has infiltrated some of the models commonly used in utility ratemaking proceedings. For example, the Risk Premium or Expected Earnings analyses rely on historical or forecasted authorized ROEs, without reference to utilities' actual cost of equity. These models in particular should be rejected outright. All other models must be examined closely and compared with data from independent financial sources to determine which, if any, are suitable for estimating the cost of equity.

4. Regulatory Standards for Setting a Fair Return on Equity

Q. Please describe the legal standards applicable to establishing a utility's authorized return on equity.

A. The United States Supreme Court established the primary objectives of utility ratemaking in two seminal cases: *Bluefield Waterworks & Improvement Co. v. Public Service Commission* (*Bluefield*), and *Federal Power Commission v. Hope Natural Gas Co.* (*Hope*).

In Bluefield, the Court established that a public utility is entitled to rates that will permit investors to earn a return "equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties," but that the utility "has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures."[14]

In *Hope*, the Court stated that setting "just and reasonable rates" is the primary objective in public utility ratemaking, which requires "a balancing of the investor and the consumer interests."[15] Consumers want to minimize rates while receiving safe and reliable service. A utility's debt investors expect to receive interest payments and, therefore, "[have] a legitimate concern with the financial integrity of the company whose rates are being regulated," meaning an interest in the utility's credit quality and ability to repay its debts.[16] Equity investors expect to receive a fair return on equity. *Hope* establishes the governing principle for judging a fair return, stating that: "[t]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. The return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital."[17]

Q. Do *Hope* and *Bluefield* establish any standards that regulators should use to determine a just and reasonable ROE?

A. Yes, *Hope* and *Bluefield* established three standards: (1) the comparable earnings standard, (2) the capital attraction standard, and (3) the financial integrity standard.

[14] *Bluefield Waterworks & Improvement Co. v. Public Service Commission*, 262 U.S. 679, 692-693 (1923).
[15] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).
[16] *Hope* at 603.
[17] *Hope* at 603.

The comparable earnings standard is derived from *Hope*'s dictate that "[t]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks."[18] The capital attraction standard is based on the requirement that a return be "sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital."[19] The financial integrity standard follows from the direction that rates must be "sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit" and enable it to raise the money necessary for the proper discharge of its public duties."[20]

Q. How should the Commission evaluate whether a given ROE meets the comparable earnings standard?

A. The *Hope* decision, in articulating the comparable earnings test, specifies that "[t]he return to the equity owner" must be comparable to returns for similarly risky investments. Because the test references the equity owner's return, it should be measured using market returns.[21] Book returns, by comparison, are a poor measure for the comparable earnings test both because equity owners do not earn

---

[18] *Supra* fn. 17.

[19] *Supra* fn. 17; *see also, Bluefield* at 693, in which the Court states that returns should be "reasonably sufficient to assure investor confidence in the financial soundness of the utility and... to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties."

[20] *Bluefield* at 693; in *Hope*, the Court added that bond holders have a "legitimate concern with the financial integrity of the company whose rates are being regulated" (*Hope* at 603).

[21] See Section 3 for a more detailed discussion on the distinction between market returns and book returns.

the utility's book return, and because a utility's forward-looking book returns can only be estimated by first determining the authorized ROE, which would create a circularity.[22] In other words, evaluating whether an ROE meets the comparable earnings standard requires estimating the cost of equity (or equivalently, expected equity returns or required returns), which is separate from an estimate of the return on book equity value that BGE or a comparably risky utility might be expected to earn.

An implication of relying on market returns for the comparable earnings test is that BGE's ROE need not be within a particular range of other utilities' ROEs to satisfy the comparable earnings test. As long as the ROE set by the Commission is at least equal to the cost of equity, investors will bid the price of equity up or down to reflect higher or lower book returns BGE is expected to earn for a given ROE, such that the price enables investors to earn, on expectation, a market return equal to their required return. Because required returns are comparable for comparably risky securities, this price-setting mechanism would make BGE's expected market return commensurate to the expected market return of comparable securities. In other words, an ROE at least equal to the cost of equity would satisfy the comparable earnings test because it would allow equity investors to set a price such that the expected market return fairly compensates

[22] S.C. Myers, *The Application of Finance Theory to Public Utility Rate Cases,* The Bell Journal of Economics and Management Science 3(1), 58–97 (1972), attached as DMC-8.

them for the risks they have taken and that is commensurate with the market return they could earn by investing in similarly risky equities.

Q. How can the Commission determine whether a particular return meets the capital attraction and financial integrity standards?

A. If a utility can attract capital at market rates, then its return is sufficient to meet the capital attraction and financial integrity standards. This follows simply from what it means to raise capital: that investors expect to earn a return that meets or exceeds their cost of capital.[23] Thus, a utility that *can and does* issue debt and raise equity is collecting rates sufficient to remain financially sound in the eyes of the market.

The *Hope* and *Bluefield* decisions do not address the terms on which capital is raised and, in a competitive market like the US equity and bond markets, companies are able to raise capital from investors offering the best price. Utilities may wish to raise capital more cheaply than the market clearing price, but this desire is irrelevant to the capital attraction standard. For example, Mr. McKenzie states that ROE must "enable the utility to offer a return adequate to attract new capital *on reasonable terms,*"[24] but that "the Court has not established specific guidelines as to terms that would be considered reasonable or unreasonable."[25]

---

[23] Myers (1972) at 80.
[24] McKenzie Direct at 5 (emphasis added).
[25] BGE Response to OPC Data Request 03-01.

However, authorizing higher returns to enable BGE to pay lower rates on its debt is grounded in neither financial theory nor the Court's standards.

Q. What ROE could the Commission authorize to meet the comparable earnings, capital attraction, and financial integrity standards?

A. An authorized ROE based on BGE's cost of equity would meet all three *Hope* and *Bluefield* standards. Professor Myers states that authorizing an ROE *equal* to a utility's cost of equity "is consistent with the comparable earnings standard established by the *Hope* case."[26] Similarly, Columbia professor James Bonbright wrote that treating fair rate of return as the cost of capital has the "claim for acceptance" that it "compli[es] with the requirement of credit maintenance and of corporate ability to attract capital on terms favorable to the company and hence to its consumers."[27]

Q. Have the courts provided guidance on the cost of equity utilities must pay relative to nonregulated entities?

A. Yes, the Supreme Court has opined that investments in utilities carry comparatively low risk and, for that reason, utilities pay a lower cost of equity than businesses in competitive industries. For example, in *Bluefield*, the Court stated that utilities have "no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures."[28] Similarly, in *Wilcox v. Consolidated Gas Co. of New York*, the Supreme Court noted that the

---

[26] Myers (1972) at 80.
[27] J.C. Bonbright, Principles of Public Utility Rates, *Columbia University Press* (1961) at 241. Available at https://www.raponline.org/knowledge-center/principles-of-public-utility-rates/.
[28] *Bluefield*, 692-693.

"amount of risk in the business is a most important factor" and found that public utilities are low-risk investments.[29]

Q. Please summarize the principles for setting a just and reasonable ROE set forth in Supreme Court jurisprudence.

A. The *Bluefield* and *Hope* decisions direct regulators to set just and reasonable rates that meet the comparable earnings, capital attraction, and financial integrity standards. An ROE that meets these standards will (1) offer investors expected returns that are commensurate with those being offered by similarly risky enterprises, (2) provide confidence in the company's finances, and (3) allow the company to maintain its credit and attract capital. Researchers and practitioners have identified that an authorized return based on the cost of capital—in other words, expected market returns—is a "fair return" and one that meets the standards enumerated by the Court.

5. Past and Current Market Data Should Inform COE Models

Q. What is the purpose of this section of your testimony?

A. In this section, I discuss how historic market returns and current valuation ratios can inform the Commission about reasonable expectations for future expected returns. Because of the equivalence between expected returns, required returns, and the cost of equity, this historic context provides guidance to the Commission

[29] *Wilcox v. Consolidated Gas Co. of New York*, 212 U.S. 19, 48-49 (1909).

about a reasonable range in which BGE's true COE lies, and thus about the range in which a just ROE should be set.

i. Historic risk and return is the proper starting point for estimating future returns.

Q. In light of the reality that setting an ROE is an inherently forward-looking endeavor, what information can today's prices provide about anticipated returns to investors and the cost of equity?

A. Both equity and bond markets are considered "efficient," meaning the price of a security reflects the relevant information available to investors at any given time. In an efficient market, prices adjust immediately to new information.[30] Numerous studies have confirmed that markets reflect all publicly available information.[31]

The most important implication of efficient markets for ratemaking purposes is that *today's prices* reflect investors' expectations and preferences *for the future*, and thus cost of capital estimates should be based on *today's prices*.[32] In other words, analyses that speculate about uncertainty in the future (e.g., that inflation or tariff policies may change) do not provide insights into investors' expectations that *are not already* reflected in prices.

---

[30] E.F. Fama, *Efficient Capital Markets: A Review of Theory and Empirical Work*, Journal of Finance, Vol. 25, No. 2 (May 1970), 383-417. Available at: https://www.jstor.org/stable/2325486.

[31] *See, e.g.,* F.K. Reily, K. Brown, and S.J. Leeds, *Investment Analysis and Portfolio Management*, Cengage (11th Ed., 2018); Morin (2006) at 279.

[32] *See, e.g.,* Morin (2006) at 279-280 ("a cost of capital estimate should be based on current prices rather than on an average of past prices. . . . Since the current stock price P_0 is caused by the growth foreseen by investors at the present time and not at any other time, it is clear that the use of spot prices is preferable.").

Q. What is the value of looking at historical data on the risk and returns of stocks when determining ROE in a ratemaking proceeding?

A. Today's prices provide the most accurate reflection of investors' expectations for the future. To translate the information in today's prices into an estimate of the COE, an analyst must estimate expected future cash flows. Almost all investors consider historical data when developing their own expectations for future returns, meaning history is embedded into investor behavior. Historical data can be extremely valuable to analysts because it offers context for (1) the range of potential outcomes, (2) how often each outcome has occurred, and (3) average outcomes.

Q. What is the equity risk premium?

A. The equity risk premium (ERP) is the additional return that an investor expects in exchange for taking equity market risk. It is one of the most important variables for estimating the COE.[33]

Q. What is the historic ERP?

A. From 1928 to 2025, the longest period for which there is reliable data, stocks have returned a 5.48 percent premium over long-term bonds, calculated as the

[33] F. Duarte & C. Rosa, *The Equity Risk Premium: A Review of Models*, Federal Reserve Bank of New York, Staff Report No. 714 (Feb. 2015). Available at: https://www.newyorkfed.org/medialibrary/media/research/staff_reports/sr714.pdf. Note that the equity risk premium is also sometimes referred to as the "market risk premium." These terms are synonymous.

difference between the geometric mean of annual returns for the S&P 500 Index and long-term government bonds.[34]

Q. How can these historical returns be helpful to the Commission in this proceeding?

A. The context provided by historic return and the historic ERP is a reasonable starting point for analysis in this proceeding. For example, Mr. McKenzie estimates the ERP to be 7.9 percent, and uses this figure in his CAPM analysis. An ERP of 7.9 percent over a ten-year period would be in the 69th percentile.[35] It is valuable for the Commission to consider that the company's analysis is based on forecasting an outcome that happens only 3 in 10 times.

ii. Valuation ratios provide information about the relationship between COE and ROE.

Q. What is a valuation ratio?

A. Valuation ratios compare a company's market price to measures of its fundamental value such as revenue, earnings, or assets. These ratios can contextualize a company's share price and provide insight into expected future returns. Price-to-Earnings and Price-to-Book are two valuation ratios commonly used by investors.

---

[34] A. Damodaran, *Historical Returns on Stocks, Bonds, Real Estate and Gold (for historical risk premiums)*, Damodaran Online (Jan. 2026). Available at: https://pages.stern.nyu.edu/~adamodar/pc/datasets/histretSP.xls. Geometric mean of annual S&P 500 and long-term government bond returns.

[35] McKenzie Direct at 49; S&P 500 return data from A. Damodaran, *Historical Returns on Stocks, Bonds, Real Estate and Gold (for historical risk premiums)*, analysis by author.

Q. Please discuss the Price-to-Earnings Ratio.

A. The Price-to-Earnings ratio (P/E) compares a company's share price to its earnings and can be calculated using trailing twelve month (TTM) EPS or expected EPS for the coming period. P/E ratios are a helpful measure to assess how much of a company's stock price performance is caused by earnings growth (which would lower P/E) or valuation growth (which would increase P/E).

Q. What is a Price-to-Book ratio?

A. The Price-to-Book Ratio (P/B ratio) compares a company's share price to the net book value of its assets per share, calculated by dividing a company's share price by the net book value per share. The P/B ratio is particularly important for evaluating the ROE of utilities because earnings are a function of rate base, which can be proxied by net book value.

Q. How do investors use valuation ratios to evaluate current market conditions?

A. Valuation ratios can help investors assess stock price and performance. When valuation ratios across the market are higher than their historical average, investors are willing to pay a higher price relative to markers of prospective earnings. For example, the higher the P/E ratio, the more investors are willing to pay per dollar of earnings the company generates today.

Investors can compare valuation ratios to historic norms at the security level, industry level, or market level, but caution should be used when comparing the valuation ratio of a stock in one industry to that of a stock in another industry because different industries have different earnings growth potential. For example, technology stocks tend to grow earnings faster than utility stocks, which means it is rational for investors to pay more per dollar of a tech stock's current earnings than a utility stock's current earnings, even if the investor wants to generate the same return from either investment.

Q. What do high valuation ratios imply about expected returns?

A. When investors are willing to pay more expensive prices to invest in a stock, it can mean (1) the market thinks the company's profits will increase at above average rates in the future; (2) the market is willing to accept lower returns in exchange for future profits (e.g., is discounting future profits at a lower rate); or (c) a combination of the two.

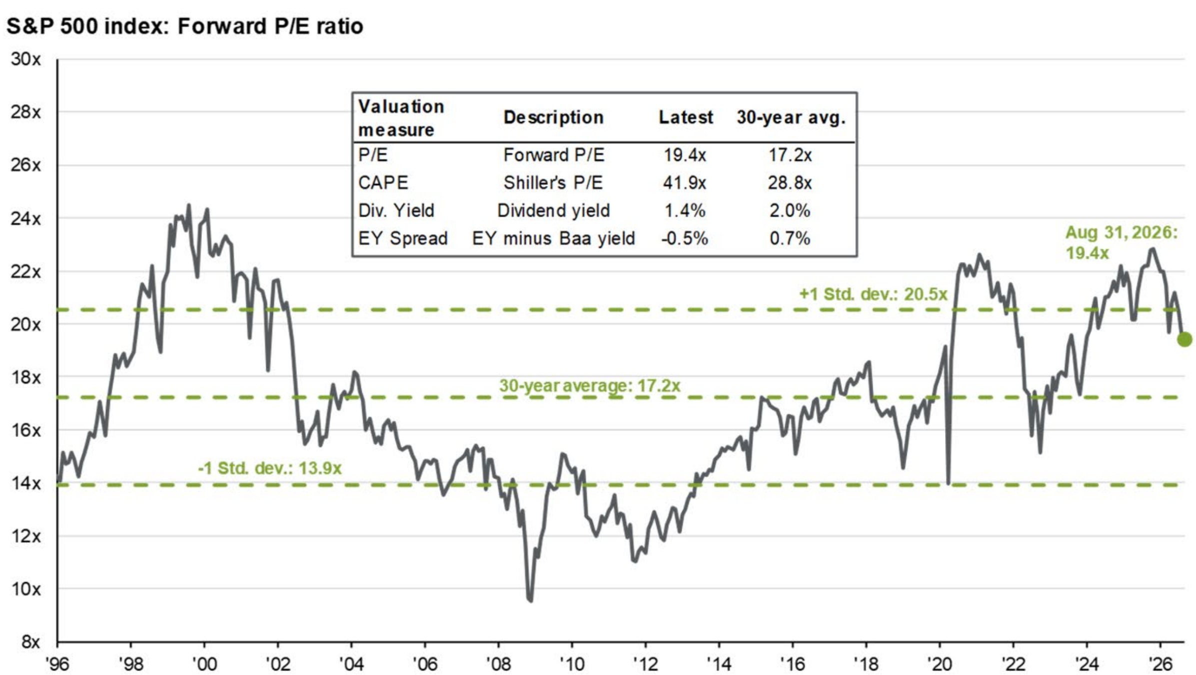
Significant evidence demonstrates that when valuation ratios are above average, expected returns for the next ten-plus years are below average.[36] Because of this, P/E ratios are a good barometer for market sentiment: when P/E ratios are very high, it is unlikely investors require above average returns.

[36] *See, e.g.,* J.Y. Campbell, and R.J. Shiller, *The Dividend-Price Ratio and Expectations of Future Dividends and Discount Factors*, The Review of Financial Studies, 1(3), 195–228 (1988). http://www.jstor.org/stable/2961997; *see also* Q. Wang, *What determines equity returns*, Vanguard Research (Oct. 22, 2025), https://corporate.vanguard.com/content/corporatesite/us/en/corp/vemo/what-determines-equity-returns.html. This does not rule out the possibility that investors *also* expect above average future growth, it simply means that lower expected returns at least partially explain high valuations.

Q. What are valuation ratios today compared to historic norms?

A. As shown in Figure 2, valuations for the S&P 500 are currently significantly higher than their long-run averages, and near their peaks over the past 30 years. J.P. Morgan's data also shows that valuations for the utility sector, measured using the P/E ratio and dividend yield, are higher than their 20-year averages.[37] In other words, market data suggests investors are willing to accept lower expected returns right now compared to historical averages.

Figure 2: S&P 500 Valuation Measures[38]



[37] *Guide to the Markets: U.S. | 3Q 2026*, J.P. Morgan Asset Management (August 2026) at 16. Available at: https://am.jpmorgan.com/us/en/asset-management/institutional/insights/market-insights/guide-to-the-markets/.

[38] Reproduced from *Guide to the Markets: U.S. | 3Q 2026* (August 2026) at 5.

Q. What drives shareholders' market returns?

A. Market returns are the sum of dividend income and capital appreciation (a change in share price). Capital appreciation itself is a combination of changes in expected future cash flows to investors and changes in valuation. Over long periods of time (e.g., a decade or longer), valuations tend to revert towards their historical mean, and growth in dividends and earnings are the primary drivers of market returns.[39] As such, understanding historic trends in dividend and earnings growth is important for assessing long-run expected market returns.

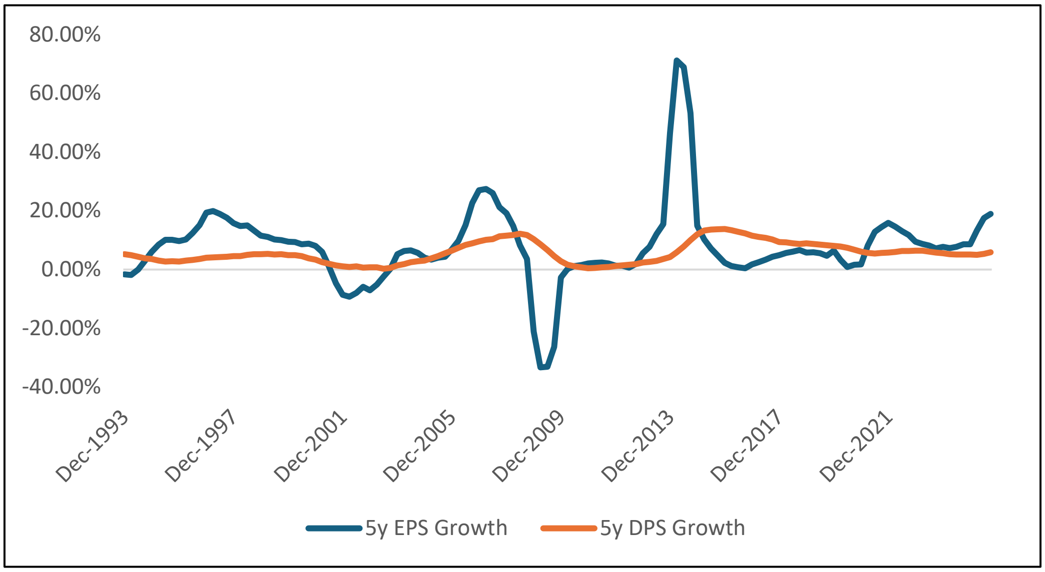
Q. Please describe the historic growth rate for earnings and dividends.

A. S&P publishes data on the earnings per share and dividends per share for companies in the S&P 500 Index from March 1988 through September 2025.[40] Reported earnings per share (EPS) grew 6.73 percent per year and dividends per share (DPS) grew 5.98 percent per year over that time. EPS is more variable than DPS, neither has maintained growth above those averages for prolonged a period of time.

[39] *What Drives Long-Term Equity Returns*, MSCI, Inc., Paper No. 2010-04 (January 6, 2010), available at: https://ssrn.com/abstract=1552125 or http://dx.doi.org/10.2139/ssrn.1552125; *see also*, R. Ibbotson and P. Chen, *Stock Market Returns in the Long Run: Participating in the Real Economy* (Mar. 2002), available at: https://papers.ssrn.com/sol3/papers.cfm?abstract_id=274150; *see also*, Q. Wang, *What determines equity returns*, Vanguard Research (Oct. 22, 2025), available at: https://corporate.vanguard.com/content/corporatesite/us/en/corp/vemo/what-determines-equity-returns.html.

[40] H. Silverblatt, *S&P 500 Earnings and Estimates Report* (Jan. 2026). Available at: https://www.spglobal.com/spdji/en/documents/additional-material/sp-500-eps-est.xlsx.

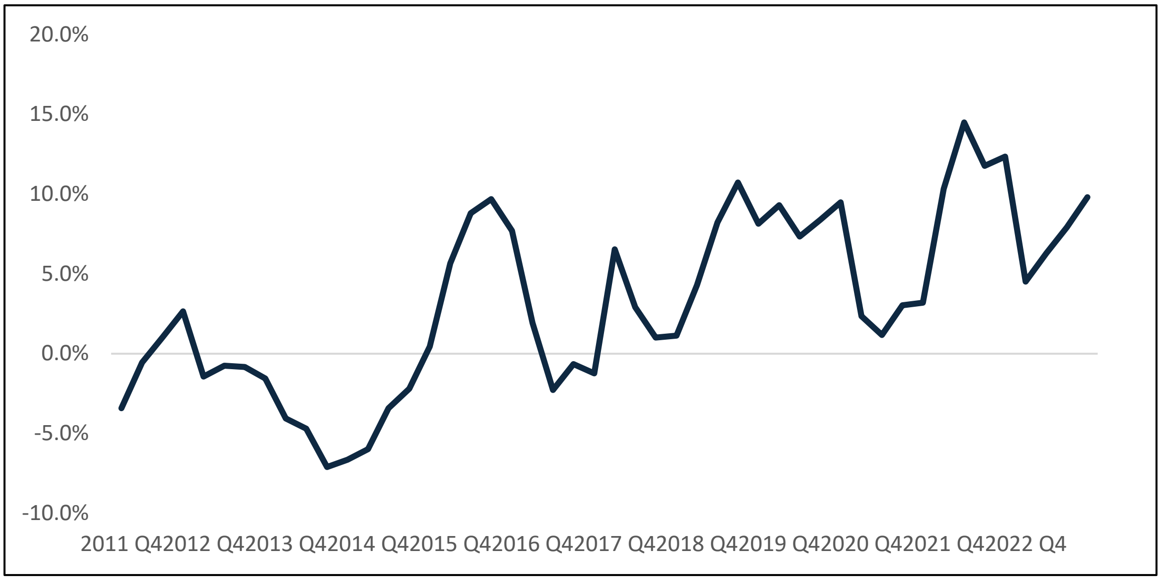
Figure 3: Rolling 5-Year EPS and DPS Growth for S&P 500 Stocks[41]



The same dataset also includes sector-specific data from March 2008 through September 2025. Over that period, annual EPS for the Utilities sector grew 3.43 percent per year.[42] Figure 4 below shows EPS growth for the Utility sector over rolling five year periods. EPS growth for the Utility sector, like the S&P Index as a whole, has varied over time, but high EPS growth rates have not persisted.

[41] S&P 500 Earnings and Estimates Report (Jan. 2026); analysis by author.
[42] S&P 500 Earnings and Estimates Report (Jan. 2026); analysis by author.

Figure 4: Rolling 5-Year EPS Growth for the S&P 500 Utility Sector



Q. Why are the trends discussed above important?

A. EPS growth is an input to the models used in this proceeding. Knowing that utilities' EPS growth is variable—elevated growth over a few years tends not to persist—and that it has averaged less than 4 percent per year are important context for evaluating the inputs used in this proceeding. Specifically, forecasts that suggest that growth well above 4 percent can be maintained over many years should be regarded skeptically.

Q. Why is the P/B ratio important in ratemaking proceedings?

A. Recall the distinction between book returns and market returns discussed in Section 3. When shareholders pay more than book value to acquire utility stock, they dilute their ability to capture the book returns that the company generates, meaning their expected market return is lower than the expected book return. If a utility's authorized ROE is close to its COE, the utility will have the opportunity to make enough profit to pay its costs, including the cost of capital, without making excess profit above its COE; this drives P/B towards 1.0. In his textbook, NYU Professor Aswath Damodaran mathematically derives the relationship between the P/B ratio, the return on equity (book returns), and the cost of equity (market returns). He stated that,

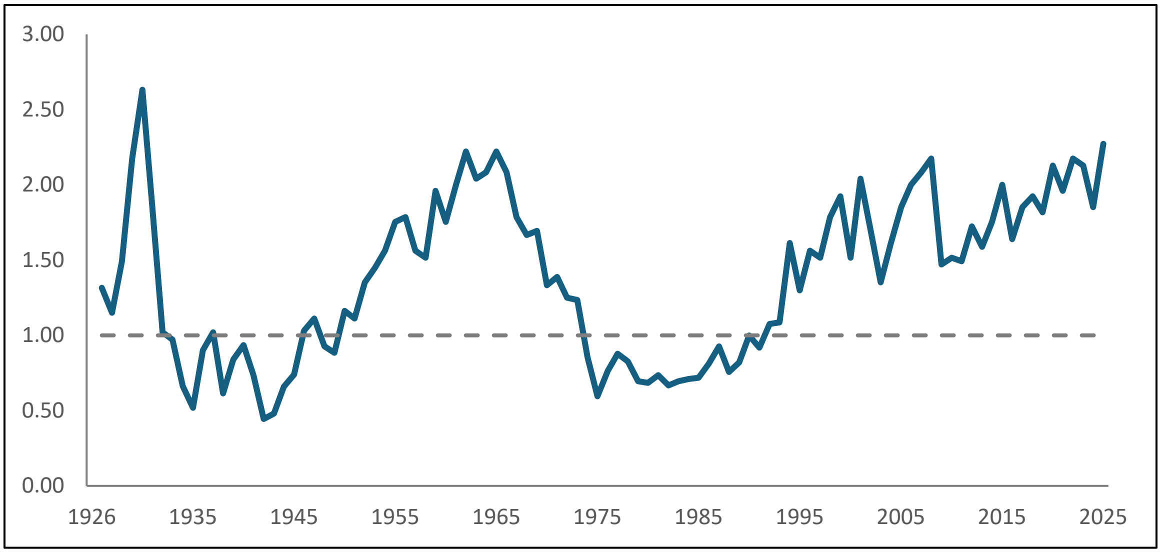
> The price-book value ratio of a stable firm is determined by the differential between the return on equity and its cost of equity. If the return on equity exceeds the cost of equity, the price will exceed the book value of equity; if the return on equity is lower than the cost of equity the price will be lower than the book value of equity.[43]

Q. What are the current P/B ratios for utilities, in general, and the studied utilities, in particular?

A. The average P/B ratio for the utility sector was 2.33 at the end of 2025 and has exceeded 1.0 for the past three decades.

[43] A. Damodaran, *Investment Valuation*, Wiley Finance (3rd Ed., 2012) at 493.

Figure 5: Average P/B Ratio for Utility Stock's Over Time[44]



For the companies in Mr. McKenzie's proxy group, the average P/B ratio as of the end of June 2026 was 2.17 as shown in Table 4 below. This data indicates that the proxy group companies have ROEs above their COE, making it inappropriate to interpret the authorized ROEs of these companies as a proxy for BGE's cost of equity.

Table 4: Price-to-Book Ratio for the McKenzie Proxy Group Companies[45]

Company	Price-to-Book Ratio
Ameren Corp.	2.29
Consolidated Edison	1.59
Fortis Inc.	1.75
NextEra Energy, Inc.	3.21
OGE Energy Corp.	2.02
Portland General Elec.	1.46

---

[44] K. French, *Current Research Returns*, Data Library, available at: https://mba.tuck.dartmouth.edu/pages/faculty/ken.french/data_library.html (accessed August 30, 2026); Value-weighted Util P/B ratios.

[45] Data from Yahoo! Finance as of August 30, 2026 (accessed September 14, 2026).

PPL Corp.	1.82
Southern Company	2.78
WEC Energy Group	2.69
Xcel Energy Inc.	2.08
Average	**2.17**

iii. Summary

Q. What should the Commission take from this section of your testimony?

A. The combination of historical returns and current valuation ratios provides useful context for understanding the returns that investors currently expect and require from their equity investments. Knowing the typical range for returns in the past is valuable because almost all investors incorporate this information into their decision-making process and expectations for the future, and therefore past returns help investors understand the likelihood of different future outcomes. The historical average is a good starting point for future expectations, and it can be combined with today's market prices and valuation ratios to create more precise expectations for the future. Research shows that high valuation ratios are a signal that expected returns—or equivalently, the cost of equity—are low, and vice versa. Because of this, and because valuation ratios are currently high, models that are implemented correctly should forecast market returns below the historical average of roughly 10 percent. In the next section, I will discuss how the forecasts published by professional investors and academics conform to this framework.

6. There is Consensus Among Academics and Investment Managers that Expected Market Returns are Lower than BGE's Requested ROE

Q. What role can academic and investment industry perspectives play in a rate case proceeding?

A. Academics and investment managers offer rigorous, unbiased evidence through their analysis and reports. Academics offer unbiased evidence on capital markets and the adherence of ROEs to asset pricing theory. Investment managers are collectively responsible for investing trillions of dollars, and thus must estimate the cost of capital to price risk correctly and make good investment decisions. Underestimating costs leads to overpaying for assets; overestimating leads to missed opportunities. Additionally, fierce competition for clients incentivizes robust, objective analysis. All of these factors contribute to investment managers' expertise in estimating the cost of capital.

Q. What are capital market assumptions?

A. Many investment managers publish capital market assumptions (CMAs), which forecast risk and returns across asset classes, typically over a 10-year horizon.

Q. Why are CMAs relevant in a rate case proceeding?

A. CMAs are useful for evaluating the expected returns—equivalently the cost of equity—for US stocks as a whole. Some differences between investment managers' CMAs and the financial models used in this proceeding are to be expected, but financial models that produce results that differ dramatically from the estimates of leading asset managers are likely not credible.[46]

Q. What expectations do the largest investment managers have for US stock returns going forward?

A. I studied CMAs from the 25 largest investment managers, and several of the largest banks with asset management and/or wealth management businesses that were published at the end of 2025 or beginning of 2026.[47] Because of overlap between the two categories, and because not all investment managers publish CMAs, I considered a total of twenty in my analysis. The results, shown in Figure 6 below, indicate a range from one percent to nine percent and an average of 6.16 percent.

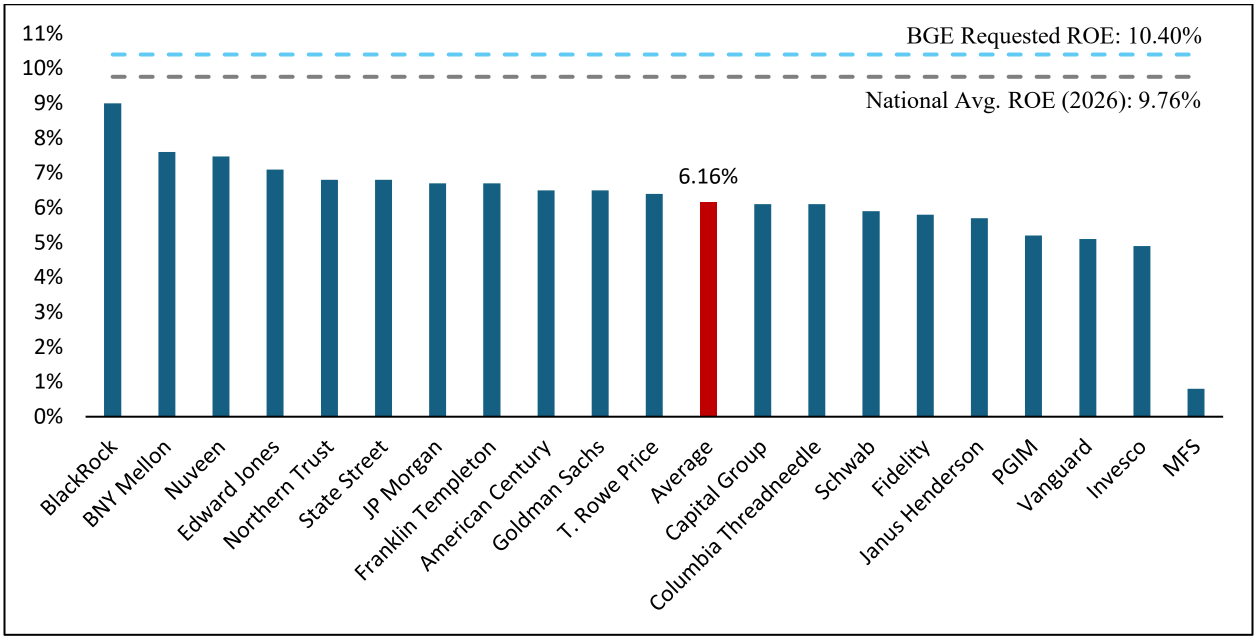
Most of the CMAs were between roughly five and eight percent; excluding an outlier forecast of one percent would raise the average to 6.44 percent. Eighteen of the twenty CMAs are within a roughly three percentage point spread from 4.90 percent to 7.60 percent. Importantly, *no* asset manager or bank published a forecast of greater than 9 percent returns for US stocks in the next decade.

---

[46] Capital Market Assumptions will often differ from cost of equity model results used in utility ratemaking because CMAs evaluate an entire asset class rather than a set of proxy stocks, and because of differing time horizons for evaluation, among other factors. However, because utility stocks are considered less risky than the broad market (see Section 3 for more detail), expected returns for US stocks broadly should be higher than expected returns for utility stocks.

[47] Largest asset managers as defined by assets under management per Morningstar. Not all asset or fund managers publish CMAs. Note that there is overlap between the largest banks and asset managers, e.g., J.P. Morgan would qualify under both categories; *see* Comparing the Largest 150 US Fund Families, Morningstar (December 5, 2024, updated February 10, 2026). Available at: https://www.morningstar.com/business/insights/blog/comparison-fund-family-digest (accessed May 1, 2026).

Figure 6: US Equity Return Expectations from Large Investment Managers



Q. How should the Commission interpret these CMAs?

A. There are two primary ways that the Commission could view the largest and most experienced investors in the country unanimously forecasting US stock returns substantially lower than BGE's current ROE and the national average authorized ROE of 9.76 percent.[48] The first is that the asset managers have done a worse job of analyzing market and economic conditions than utility witnesses like Mr. McKenzie, who testified that he believes investors currently require a 10.4 percent return from stocks with similar risk as BGE.[49] The far more plausible alternative is that authorized ROEs are inflated relative to the returns investors currently require from US stocks as a whole, let alone low-risk utility stocks. Given that large asset

[48] S&P RRA for rate case data; 9.76% is the average ROE authorized in electric rate case decisions in January to August 2026.
[49] McKenzie Direct at 3.

managers are better resourced, more experienced, and more incentivized to be objective than utility witnesses in a rate case, the Commission should interpret these results as evidence that authorized ROEs currently exceed the actual COE.

Q. Is there any academic evidence that supports this view?

A. Yes. Academic estimates of the COE are aligned with the estimates published by asset managers. Further, academic researchers have found that authorized ROEs cannot be explained by asset pricing theory, which means that ROEs are not being set based on the cost of equity as required by *Hope* and *Bluefield*.

Q. What academic evidence is there on the COE?

A. Since 1999, New York University Stern School of Business (NYU Stern) Professor of Finance Dr. Aswath Damodaran has published data on the COE for US Equities.[50] The results are freely available, published annually on the NYU Stern website, and are based on the same standard financial formulas used throughout the investment industry.[51]

Q. Why are the estimates on the COE published by Professor Damodaran credible?

A. Professor Damodaran has taught and researched finance at NYU Stern for more than a quarter century, has published a leading textbook on investment valuation

[50] A. Damodaran, *Cost of Equity and Capital (US)*, Damodaran Online (Jan. 2026). Available at: https://pages.stern.nyu.edu/~adamodar/New_Home_Page/datafile/wacc.html.
[51] A. Damodaran *Cost of Equity and Capital (US)* (Jan. 2026).

and finance, and has been called the "Dean of Valuation."[52] In short, Professor Damodaran is highly credentialed, experienced, and credible.

Q. What is Professor Damodaran's current estimate of the COE?

A. Professor Damodaran estimates that the cost of equity for the Total Market is 8.02 percent. Among the 94 sectors in Professor Damodaran's dataset, Utilities have the lowest COE: 5.02 percent. There are only four sectors in the dataset with an estimated COE higher than BGE's requested 10.4 percent ROE.

Professor Damodran's roughly 8.02 percent COE estimate is similar to the 6.16 percent average CMA published by asset managers, despite the fact that they may use different methods and consider different time horizons.[53] Both sets of estimates are much more closely aligned to each other than to the 12.7 percent market return Mr. McKenzie forecasts in his CAPM analysis.[54] In the context of investment industry and academic analysis, Mr. McKenzie's estimate stands as a clear outlier.

Q. Is there any other academic evidence that is relevant to this proceeding?

A. Yes, there are several other academic studies that have analyzed authorized ROEs and found that ROEs are inflated relative to widely accepted markers of the cost of

[52] K. Harris, *Professor Aswath Damodaran on Valuation*, Forbes (Jul. 17, 2018). Available at: https://www.forbes.com/sites/kevinharris/2018/07/17/professor-aswath-damodaran-on-valuation/.

[53] CMAs typically estimate returns over the next ten years, Professor Damodaran's COE estimate is a snapshot as of January 2026.

[54] McKenzie Direct at 49.

capital. I will address three studies from the (1) University of California, Berkeley, (2) Carnegie Mellon and (3) Columbia.

Q. Please explain the findings from researchers at the University of California, Berkeley (Berkeley) regarding the premium in authorized ROEs.

A. Researchers at Berkeley found that investor-owned utilities have been granted "a premium in approved returns on equity ranging from one to five percentage points over the past three decades."[55] A premium, in this context, is the amount by which an authorized ROE exceeds COE. The researchers used multiple approaches to measure the COE utilities face and concluded that their highest estimates are below the ROEs that have been authorized. The researchers estimate that inflated ROEs have cost American ratepayers $7 billion annually for the past three decades.[56]

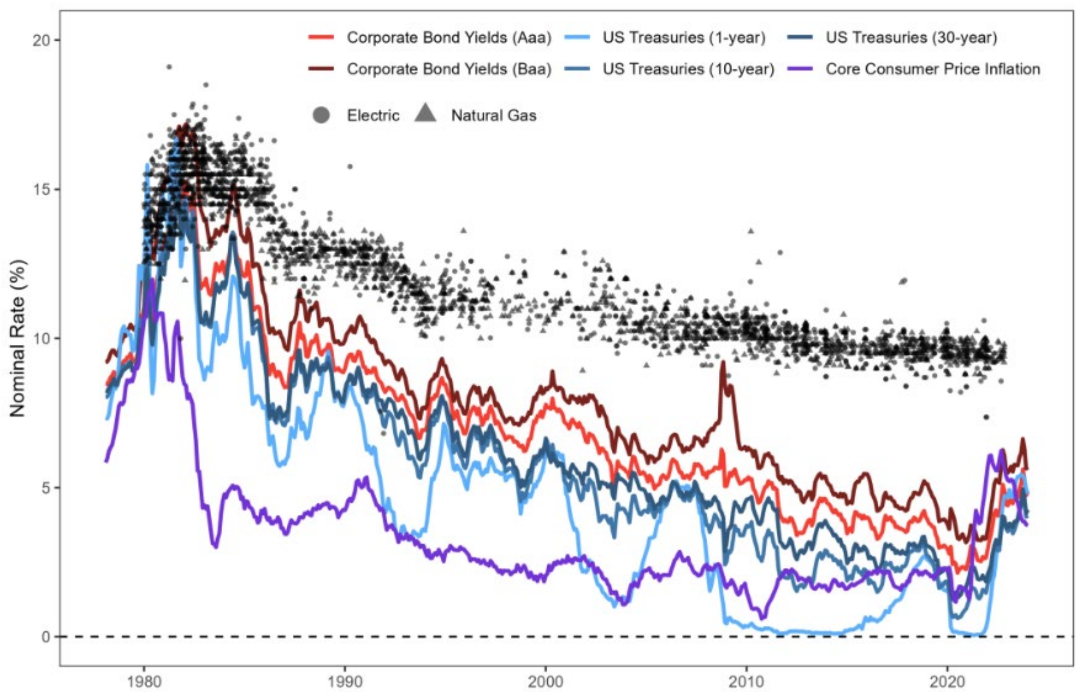
Q. What was the primary driver of the increasing premiums in approved ROEs according to the researchers?

A. There has been a large decline in interest rates (a benchmark for the cost of capital) since the early 1980s. During that time, 30-year US Treasury rates have fallen from roughly 12 percent to 4.9 percent (this includes the recent increases in rates).[57] Over that same time, the average authorized ROE fell at a significantly

[55] K.D., and S. Jarvis, *Rate of Return Regulation Revisited*, Energy Institute at Haas (Mar. 2025). Available at: https://haas.berkeley.edu/wp-content/uploads/WP329.pdf, attached as Attachment DMC-9.
[56] Werner and Jarvis (2025).
[57] *Market Yield on U.S. Treasury Securities at 30-Year Constant Maturity*, Federal Reserve Bank of St. Louis (access September 8, 2026). Available at: https://fred.stlouisfed.org/series/DGS30. 4.9 percent refers to the yield on 30-Year US Treasuries as of April 2026, the dates that Mr. McKenzie used for his analysis.

slower rate, which lead to difference between the average ROE and 30-year US Treasury rates to double from between 2 to 3 percent in the early 1980s to 5 to 6 percent today. Figure 7 below, reproduced from the original paper, illustrates this trend over the past several decades.

Figure 7: Authorized ROEs vs. Benchmarks for the Cost of Equity[58]



[58] Werner and Jarvis (2025).

Q. Would the trend in authorized ROEs and US Treasury rates look similar if other utilities are removed from the analysis?

A. Yes, Figure 8 and Figure 9 below depict the information about BGE's ROE and US Treasuries. Those figures show that in the five year period from November 1979 to November 1984, BGE's authorized ROE was 2.44 percent higher than 30-Year Treasury rates on average.[59] From the mid-1980s until 2020, this spread increased from 2.44 percent to as high as 9.06 percent. Over the last five years ending August 30, 2026, BGE's authorized ROE has been 5.42 percent higher than 30-Year Treasury rates on average. Even though rising interest rates over the past few years have compressed the premium of BGE's ROE over US Treasuries, the premium is still more than double what it was several decades ago.

[59] Rate case data from S&P RRA; Federal Reserve Bank of St. Louis for Treasury Yields; spread calculated by author.

Figure 8: BGE Authorized ROEs Since 1979[60]

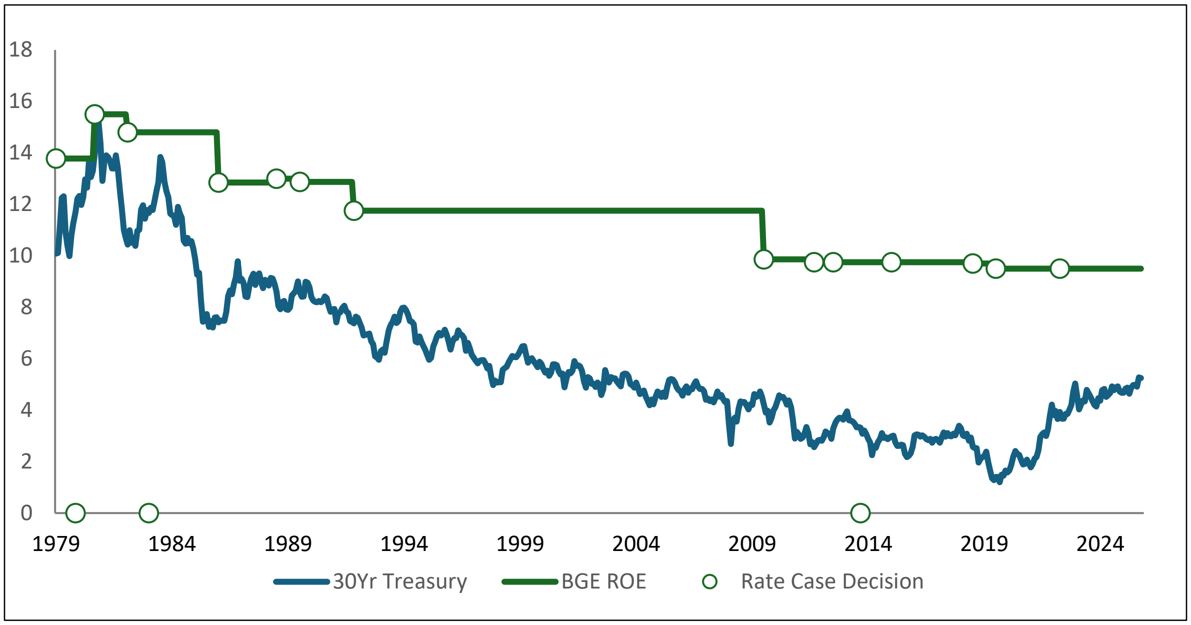
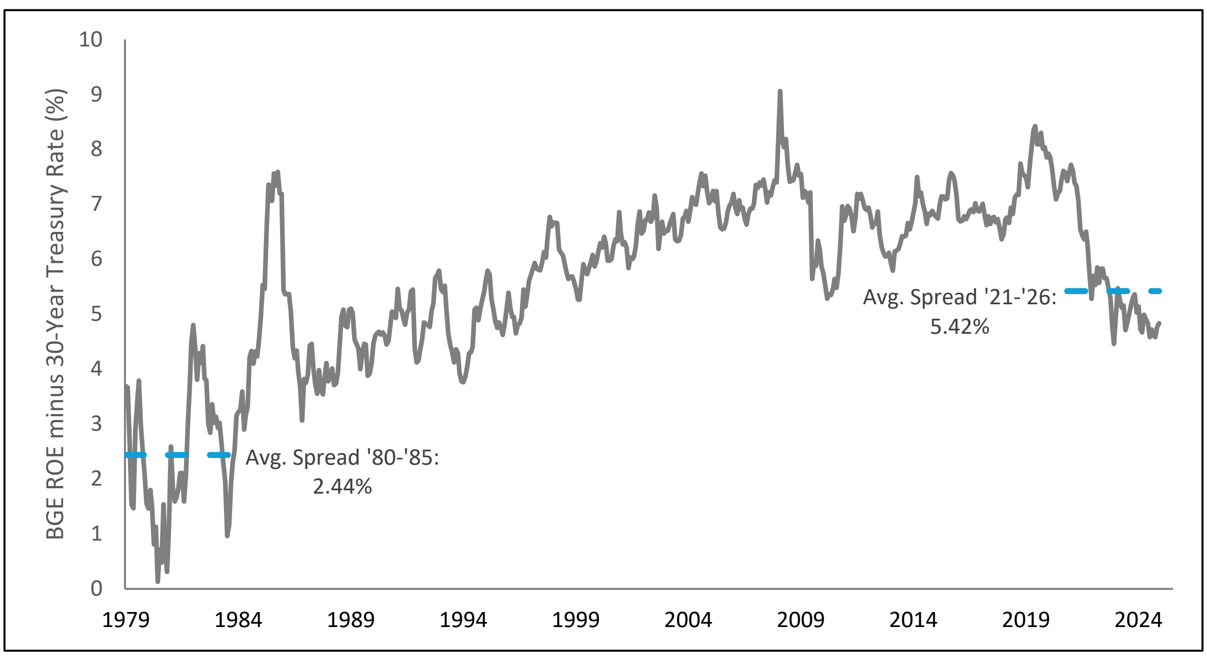


Figure 9: BGE's Authorized ROE minus 30-Year Treasury Rates[61]



---

[60] S&P RRA for rate case and ROE data; *Market Yield on U.S. Treasury Securities at 30-Year Constant Maturity*, Federal Reserve Bank of St. Louis (accessed September 8, 2026). Available at: https://fred.stlouisfed.org/series/DGS30.
[61] *Id.*

Q. Does Mr. McKenzie agree that there is a relationship between interest rates and the COE?

A. Yes. Mr. McKenzie states that, "[y]ields on 30-year Treasury bonds are generally accepted as a guide to the risk-free rate. While yields on long-term Treasury bonds can be impacted by monetary policy (e.g., quantitative easing) or a flight to safety in times of turmoil, they provide an observable benchmark for underlying trends in capital costs."[62] In response to discovery, Mr. McKenzie confirmed that "the returns required by investors on Treasury bonds, debt securities and common stock would be expected to move in the same direction, although not in lockstep." [63] In other words, decreasing US Treasury bond yields over the past 40 years indicate a decline in the cost of capital over that time.

Q. Have any other studies also concluded that authorized ROEs are inflated relative to utilities' COE?

A. Yes, studies conducted by Carnegie Mellon[64] and Columbia[65] have come to similar conclusions.

Rode and Fischbeck at Carnegie Mellon conclude that "rates of return authorized by U.S. state regulatory agencies… [demonstrate] a growing spread over the riskless rate of return across the time horizon studied. The size and

---

[62] McKenzie Direct at 19.

[63] BGE Response to OPC Data Request 03-03.

[64] D. Rode & P. Fischbeck, *Regulated Equity Returns: A Puzzle*, Energy Policy, 133: 110891 (Oct. 2019). Available at: https://doi.org/10.1016/j.enpol.2019.110891, attached as Attachment DMC-10**.**

[65] S. Azgad-Tromer & E.L. Talley, *The Utility of Finance*, Columbia University School of Law Center for Law & Economic Studies, Working Paper No. 569 (2017) at 25. Available at: https://scholarship.law.columbia.edu/faculty_scholarship/2042/.

growth of this spread—the risk premium—does not appear to be consistent with classical finance theory, as expressed by the CAPM. In fact, regression analysis of the data suggests the *opposite* of what would be predicted if the CAPM holds."[66]

Similarly, Columbia professors analyzed how authorized ROEs compared to expected rates of return using standard asset pricing models and found "that rate setting practices adopted by [public utility commissions] diverge appreciably (even violently) from the predictions of financial economics across numerous dimensions."[67] In fact, the mean awarded ROEs analyzed in this study were such outliers from the financial industry that they were higher than returns from "Fortune Magazine's top twenty investments from the last decade."[68]

Finally, a suite of recent articles from former regulators,[69] power producer executives,[70] and non-profit research organizations[71] all unanimously conclude that authorized ROEs are higher than the true COE that utilities face. Collectively, these articles, alongside the set of studies discussed above, offer a suite of

[66] D. Rode & P. Fischbeck (2019).
[67] Azgad-Tromer & Talley (2017).
[68] Azgad-Tromer & Talley (2017).
[69] J. Van Nostrand, *The Circle Game: Estimating the Cost of Equity Capital* (Mar. 19, 2026). Available at: https://basedrates.substack.com/p/the-circle-game-estimating-the-cost#footnote-anchor-1-191405506.
[70] M. Lee, *The Utility Business Model Is Built for a Different Era. Regulators Are Starting to Notice.* (Feb. 24, 2026). Available at: https://distributedgrid.substack.com/p/the-utility-business-model-is-built?triedRedirect=true.
[71] D. Tait, S. Green, and S. Sturgis, *Paying for Their Profits: How Ratepayers Foot the Bill for Soaring Utility Profits,* Energy & Policy Institute (Mar. 12, 2026). Available at: https://energyandpolicy.org/utility-profit-report/.

evidence that BGE's current 9.5 percent ROE, let alone its proposed 10.4 percent ROE, is higher than its actual COE.

Q. Can you summarize the evidence that academic research and professional investment managers can offer the Commission?

A. In summary, academic researchers and investment managers offer experience and expertise in asset pricing and valuation. The Commission should use the rigorous, unbiased evidence these experts publish when evaluating BGE's ROE. CMAs are a useful benchmark of the industry's expectations for stock market returns. Expected return estimates from asset managers and academic researchers generally conclude that the COE for US stocks as a whole is currently no higher than 8 percent.[72] Because utility stocks are less risky than the average US stock, this means that 8 percent should be viewed as the highest reasonable estimate for the cost of equity for a US utility; indeed, the true COE for a utility is likely significantly lower than that. Currently, the average authorized ROE for electric utilities is 9.76 percent, well above this 8 percent ceiling.[73] Studies from multiple universities, as well as articles from former regulators and energy industry participants, all reach the same conclusion: authorized ROEs currently exceed utilities' actual cost of equity.

[72] Nineteen of twenty CMAs, plus Professor Damodaran's market data estimate expected market returns of 8 percent or lower, with the lone exception being BlackRock's estimate of 9 percent.
[73] S&P RRA rate case data for January through August 2026.

7. Models & Analysis to Estimate the Cost of Equity

Q. Which models did you use to estimate BGE's cost of equity?

A. My analysis considers the results from a Capital Asset Pricing Model and Discounted Cash Flow model. Both models have been heavily studied by academics and the investment community and are frequently used in regulatory proceedings.

Q. What companies did you consider for your proxy group?

A. I began with Mr. McKenzie's proxy group and then removed NextEra Energy (ticker: NEE) due to the merger with Dominion Energy that was announced in May 2026.[74] Throughout my testimony, to make my results more directly comparable with Mr. McKenzie's, I show results using both Mr. McKenzie's proxy group, my revised proxy group, and Exelon Corporation (ticker: EXC).

i. Capital Asset Pricing Model

Q. Please explain the Capital Asset Pricing Model.

A. The Capital Asset Pricing Model (CAPM) is the most popular method for estimating expected returns. The CAPM estimates expected return as a function of the return on a risk-free asset plus a premium for exposure to the risk of the overall

[74] "NextEra Energy and Dominion Energy to Combine, Creating the World's Largest Regulated Electric Utility Business and North America's Premier Energy Infrastructure Platform Benefiting Customers." *NextEra Investor Relations* (May 18, 2026), https://www.investor.nexteraenergy.com/news-and-events/news-releases/2026/05-18-2026-123054903. After the announcement of a proposed merger, the stock price of a company begins to reflect the economics of the proposed merger, making the company's result an inappropriate measure for COE; *see also* BGE Response to Data Request OPC 11-03, in which Mr. McKenzie confirms he would remove NEE from his proxy group were he to re-run his analysis today.

market. Company-specific risk can be diversified away, but market risk cannot. Rational investors should expect higher returns for systematic (market) risks that cannot be diversified away, but not for company-specific risks.[75] Formally, the CAPM estimates the return on a security as:

$$\text{Expected Return} = R_f + \text{Beta} * (R_m - R_f)\text{, where:}$$

R_f = the return on a risk-free asset
Beta = the security's exposure to the market
R_m = the return on the market portfolio

The additional return for the market portfolio above the risk-free rate of return is referred to as the equity risk premium (ERP) or market risk premium (MRP).

Q. Please describe the risk-free rate that you used in your analysis.

A. The risk-free rate is the return an investor can receive without assuming any risk. It is typically based on the return on US Treasuries. The biggest question when estimating the risk-free rate is which US Treasury to use.

Treasuries with shorter maturities will have little to no price risk but may have reinvestment risk if the time horizon of the analysis is longer than the Treasury's maturity. For example, an investor who wants to calculate expected returns for the next 20 years may choose a 6-month Treasury Bill as her risk-free rate, virtually guaranteeing that her principal will not lose value. However, the Treasury Bill will mature and need to be reinvested 40 times over the course of her

[75] E.F. Fama and K. French, *The Capital Asset Pricing Model: Theory and Evidence*, Journal of Economic Perspectives, 18(3), 25-46; *see also* J. Graham, S. Smart, and W. Megginson, *Corporate Finance: Linking Theory to What Companies Do,* South-Western Cengage Learning (3rd ed., 2010).

time horizon, and each time there is a risk that the return she can earn from the new 6-month Treasury Bill will be lower. To minimize the combination of price risk and reinvestment risk, it is common in corporate finance and valuation to use 10-year US Treasuries.

Because it is common to use 10-year US Treasury yields as a measure of the risk-free rate, I do so in my CAPM analysis. Specifically, I use the average yield on 10-year US Treasuries throughout August 2026.

Q. Did you use forecasts of interest rates in your analysis?

A. No. The use of forecasted interest rates is unnecessary and can introduce a source of bias into the CAPM. Recall from Section 5 that markets are remarkable information processing machines, and that prices today reflect the information available to investors, including expectations for the future. The implication is that today's Treasury yields are the best forecast available for Treasury yields in the future. Indeed, researchers found that assuming rates will not change produces a smaller error on average than the rate predicted by analysts, including Blue Chip.[76]

Q. Why did you calculate an average yield over one month?

A. There is substantial evidence that markets are highly efficient, and thus current prices offer the best view into investors' current expectations and return

[76] H. Baghestani, *Forecasting in Efficient Bond Markets: Do Experts Know Better?*, International Review of Economics & Finance, 18(4): 624-630 (Oct. 2009), https://doi.org/10.1016/j.iref.2008.10.007; *see also* G. Duffee, *Forecasting Interest Rates* in *Handbook of Economic Forecasting Vol. 2, Part A,* Elsevier (2013) at 385–426*; see also* M.D. Bauer and J.D. Hamilton, *Do Macro Variables Help Forecast Interest Rates?*, Federal Reserve Board of San Francisco (Jun. 2016), https://www.frbsf.org/wp-content/uploads/el2016-20.pdf.

requirements. This was discussed in more detail in Section 5, and is supported by academics such as Stewart Myers and Roger Morin.[77] Consistent with market efficiency, I use recent prices. The average yield over a month balances the need to use current information with the need to reduce the impact day-to-day volatility could introduce into the CAPM analysis.

Q. Please explain how you calculated beta for your analysis.

A. I calculated beta for each security in the proxy group as the average beta reported by Yahoo! Finance and Zacks as of August 31, 2026. Both Yahoo! Finance and Zacks use five years of data to calculate beta.

Q. Please explain how you estimated the ERP for your CAPM analysis.

A. I average four estimates of the ERP for my CAPM analysis. I did not conduct my own analysis to estimate the ERP because estimates of expected returns for the S&P 500 Index are already produced by firms with strong incentives to correctly estimate the cost of capital.

The first two estimates come from Professor Damodaran's data. His annual update includes estimates of the Historic ERP and the Implied ERP given current

[77] *See, e.g.,* Myers (1972) at 73 ("[market efficiency] indicates that observed prices at any time t approximate the equilibrium values, given [current information]. Thus, an estimate of [the required return] at time t should be based on prices at t, not on an average of these and previous prices. There is no point in 'smoothing' stock price series"); *see also* Morin (2006) at 280 ("since the current stock price P_0 is caused by the growth foreseen by investors at the present time and not any other time, it is clear that the use of spot prices is preferred.").

market conditions. As of the end of 2025, the Historic ERP was 5.48 percent and the Implied ERP was 4.23 percent.[78]

The third estimate of the ERP leverages the results of the quarterly *CFO Survey* conducted by the Federal Reserve Banks of Atlanta and Richmond. The 367 CFOs surveyed in Q2 2026 expected annual S&P 500 returns of 9.7 percent for the next 10 years, yielding a 5.02 percent ERP estimate.[79]

The final estimate of the ERP follows a methodology developed by McKinsey & Company. McKinsey studied forward-looking COE estimates and determined the cost of equity has remained roughly 7 percent in real dollars.[80] Adding expected inflation provides an estimate of the forward-looking COE. As a measure of expected inflation, I used the 10-Year Breakeven Inflation Rate, which was 2.29 percent in August 2026.[81] Those inputs produce the fourth ERP estimate, 4.60 percent.[82]

---

[78] A. Damodaran (*Historical Returns on Stocks, Bonds, Real Estate and Gold,* Jan. 2026); A. Damodaran, *Implied ERP (annual) from 1960 to Current*, NYU Stern (Jan. 2026), https://pages.stern.nyu.edu/~adamodar/pc/datasets/histimpl.xls.

[79] *The CFO Survey – Q2 2026,* Duke Fuqua School of Business, Federal Reserve Banks of Richmond and Atlanta (May 18 – Jun. 5, 2026), https://www.richmondfed.org/research/national_economy/cfo_survey/data_and_results/2026/20260325_data_and_results. The estimated ERP was calculated by subtracting the risk-free rate of return of 4.68 percent from the expected returns of 9.7 percent.

[80] V. Gupta, D. Kohn, T. Koller, and W. Rehm, *Markets versus textbooks: Calculating today's cost of equity*, McKinsey & Company (Jan. 24, 2023), https://www.mckinsey.com/capabilities/strategy-and-corporate-finance/our-insights/markets-versus-textbooks-calculating-todays-cost-of-equity.

[81] *10-Year Breakeven Inflation Rate [T10YIE]*, Federal Reserve Bank of St. Louis (accessed September 3, 2026). https://fred.stlouisfed.org/series/T10YIE.

[82] This estimate was calculated by adding McKinsey's real dollar ERP (7%) to the 10-Year- Breakeven Inflation Rate (2.29%) and then subtracting the risk-free rate (4.68%).

Across the four measures I considered, the low ERP was 4.23 percent, the high ERP was 5.48 percent, and the average ERP was 4.83 percent. Expecting an ERP that is slightly lower than the historic average ERP (5.48 percent) is consistent with the fact that valuations are currently higher than historic averages. When valuations are higher, investors are willing to pay more for each dollar of earnings, translating to lower expected returns.[83]

Q. What were the results of your CAPM analysis?

A. Table 5 below provides a summary of my CAPM analysis results; the full results are available as Attachment DMC-3. The low, high, and average estimates were 6.55 percent, 7.10 percent, and 6.81 percent, respectively.

Table 5: Summary of CAPM Results

	Low COE Estimate (%)	High COE Estimate (%)	Average COE Estimate (%)
Cassara Proxy Group	6.55	7.10	6.81
McKenzie Proxy Group	6.63	7.21	6.91
Exelon Corporation	6.14	6.57	6.35

ii. Discounted Cash Flow Model

Q. Please explain the Discounted Cash Flow Model.

A. The Discounted Cash Flow (DCF) model is based on the idea that the price of a stock is the present value of the cash flows it is expected to generate in the future.

$$Price = \frac{D_1}{1+K} + \frac{D_2}{(1+K)^2} + \dots + \frac{D_n}{(1+K)^n}$$

[83] For a more in-depth discussion on valuations and their role in expected future returns, please see Section 5.

These cash flows come primarily in the form of dividends, but can also come via share buybacks. In a generalized DCF model, the price of a stock is calculated as:

Where:	*Price*	=	*Current stock price*
	D_1....	=	*Expected future cash flows*
	K	=	*Discount rate / expected*

The generalized DCF model can be simplified into a few common forms depending on the assumptions an analyst makes about the growth rate for expected future cash flows over time.

Q. Please explain the Constant Growth DCF.

A. The Constant Growth DCF is the most common form of the DCF used in regulatory proceedings. This model is appropriate for mature companies, like most utilities, that are growing at a stable rate.[84] Under the assumptions that (i) cash flows to shareholders grow as a constant rate, (ii) the discount rate remains constant, and (iii) valuation ratios remain stable, the generalized DCF can be simplified into a Constant Growth DCF:

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

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

Where *K* is the cost of equity (equivalently, the discount rate or the expected return), D_1 is the expected cash flows in the next period, P_0 is the current stock

[84] A. Damodaran, *Discounted Cash Flow Models: What They Are and How to Choose the Right One*, NYU Stern, https://pages.stern.nyu.edu/~adamodar/New_Home_Page/lectures/basics.html.

price, and g is the expected growth rate of future cash flows. Given the assumptions above, the cost of equity equals dividend yield plus expected growth in future cash flows.

Q. Please summarize the Constant Growth DCF Model you used to estimate BGE's COE.

A. For each company in the proxy group, I estimated the three variables for the Constant Growth DCF as follows:

(1) Dividends: I used the forward dividend forecast from Yahoo! Finance as of August 31, 2026.

(2) Price: I used the average adjusted closing stock price for August 2026.

(3) Expected Growth Rate: I considered two sustainable long-run growth rates that are consistent with the Constant Growth DCF's requirement that the expected growth not exceed the growth rate of the economy. First, I used the long-run nominal GDP growth forecast from the U.S. Congressional Budget Office (CBO), which is 3.80 percent.[85] Second, I use the historical compound growth rate in EPS for the S&P Utility Sector, which is 3.43 percent.[86]

---

[85] *The Long-Term Budget Outlook: 2026 to 2056*, U.S. Congressional Budget Office (Feb. 25, 2026), https://www.cbo.gov/publication/62044. The U.S. CBO estimates nominal GDP will grow by an average rate of 3.8 percent from 2026 to 2056.

[86] H. Silverblatt, *S&P 500 Earnings and Estimates Report* (Jan. 2026), https://www.spglobal.com/spdji/en/documents/additional-material/sp-500-eps-est.xlsx. Trailing twelve month earnings grew from $11.61 in Q4 of 2008 to $20.44 in Q3 of 2025, a compound growth rate of 3.43 percent.

Q. Please elaborate on the requirement that the expected growth rate not exceed the growth rate of the economy.

A. A key tenet of the Constant Growth DCF is that the growth rate for the company or proxy group cannot exceed the growth rate of the overall economy in which they operate. For example, Dr. Morin writes "eventually all company growth rates, especially utility services growth rates, converge to a level consistent with the growth rate of the aggregate economy."[87] A company with a perpetual growth rate higher than the economy's will eventually become the entire economy, an obviously absurd outcome.[88]

Large, mature economies like the United States do not grow more than 2 percent to 3 percent in real terms, or 4 percent to 5 percent in nominal terms. The CBO's latest forecast is for 3.8 percent GDP growth for the next three decades.[89] Similarly, McKinsey & Company states that a proper Constant Growth DCF for US companies should have a growth rate no higher than approximately 4 percent, comprised of 2 percent inflation and 2 percent GDP growth. Finally, John Burr Williams, the creator of the DCF, and Professor Damodaran both conclude that stable growth rates of 1 to 2 percent are reasonable, while also contending that "no company can continue to grow in dividend-paying power forever."[90]

---

[87] Morin (2006) at 308.
[88] McKinsey & Co., *Measuring and Managing the Value of Companies* at Chapter 12, Wiley (8th ed., May 20, 2025).
[89] U.S. Congressional Budget Office (Feb. 2026).
[90] J. Burr Williams, *The Theory of Investment Value*, North Holland Publishing Company (1938) at 87, https://ia601506.us.archive.org/18/items/in.ernet.dli.2015.225177/2015.225177.The-Theory.pdf; *see also* A. Damodaran, *Investment Valuation*, Wiley Finance (3rd Ed., 2012) at 304.

Q. Why did you use one month of prices to calculate an average price?

A. As in my CAPM model, I use recent prices in my analysis because that is consistent with evidence that markets are highly efficient, and thus recent prices offer the best view into investors' current expectations and return requirements. The average of prices over a month balances the need to use current information with the need to reduce the impact day-to-day volatility could introduce into the DCF analysis.

Q. What were the results of your Constant Growth DCF analysis?

A. I ran a Constant Growth DCF using the inputs described above for each company in the proxy group and Exelon. The full results are available in Attachment DMC-4.

Using CBO's GDP forecast as the long-run growth rate, the mean COE for the Cassara proxy group, McKenzie proxy group and Exelon were 7.27 percent, 7.22 percent, and 7.64 percent, respectively. Using the compound growth rate of S&P Utility companies' EPS as the long-run growth rate, the average COE for the Cassara proxy group, McKenzie proxy group and Exelon were 6.90 percent, 6.86 percent, and 7.27 percent, respectively.

Table 6: Summary of Constant Growth DCF Results

Perpetual Growth Rate	Cassara Proxy Group	McKenzie Proxy Group	Exelon
US GDP Growth	7.27%	7.22%	7.64%
Utility Sector EPS Growth	6.90%	6.86%	7.27%
Average	**7.08%**	**7.04%**	**7. 46%**

Q. Please describe other variations of the DCF model that you considered in your analysis.

A. Earnings growth for utilities is expected to rise over a short-to-medium term horizon of 3 to 5 years because the rapid buildout of new infrastructure to meet the needs of data centers, electric vehicles, and other electrifying load could lead to a substantial expansion of utilities' rate base. This is reflected in the analyst EPS growth forecasts of 7 percent that Mr. McKenzie cites in his direct testimony, as well as in Professor Damodaran's data showing that EPS for utilities is expected to grow 6.91 percent for the next five years; both figures are substantially above the 3.43 percent rate at which the utility sector has grown earnings since 2008, when S&P began tracking this data.[91]

When there are short-run shifts in expectations, extrapolating those short-run trends into perpetuity can overstate the COE. For example, Dr. Morin writes, "the [constant growth] DCF model would be incorrectly specified when the

[91] BGE Exhibit AMM-5; A. Damodaran, *Historical (Compounded Annual) Growth Rates by Sector*, NYU Stern (Jan. 2026), https://pages.stern.nyu.edu/~adamodar/New_Home_Page/datafile/histgr.html.

investors' expected intermediate EPS growth rate differs from the long-term sustainable EPS growth rate."[92]

To account for the expectation that utilities' short-run EPS growth may be higher than a sustainable long-run rate, I use the results of my Constant Growth DCF as a check for robustness, but do not factor them into my final ROE recommendation. Instead, I use the results from a Multi-Stage DCF model to form my recommendation. Relying on the Multi-Stage DCF avoids the mistake of forecasting elevated short-run growth forecasts into perpetuity while reflecting the industry's accelerated rate base and accompanying earnings growth.

Q. Please explain how the Multi-Stage DCF model works.

A. A Multi-Stage DCF is refinement of the Constant Growth DCF that considers different rates of growth over short, intermediate, and long time horizons. Analyst forecasts for EPS growth are used to proxy short-term growth and the sustainable growth rate is used for the long-term. In between, growth is assumed to transition between the analyst forecasts and the sustainable long-term growth rate over a period of 10 years.

Q. What inputs did you use in your Multi-Stage DCF?

A. Consistent with my Constant Growth DCF, I used the following inputs:

[92] Morin (2006) at 286.

(1) Dividends: I used the trailing twelve months of dividends (through Q2, 2026) as the starting dividends, and then escalated dividends per share by each year's estimated growth rate.

(2) Price: I used the daily adjusted closing stock price for August 2026.

(3) Short-term growth: I used the average of the EPS growth forecasts from Zacks and S&P Capital IQ.

(4) Long-term Growth Rate: I consider the long-run nominal GDP growth forecast from the CBO and the long-run compound growth rate in EPS for the S&P Utility Sector.[93]

Q. What were the results of your Multi-Stage DCF analysis?

A. The results of my DCF analyses are shown in Table 7 below; more detail is available in Attachments DMC-4 and DMC-5. As discussed above, I use the Constant Growth DCF as a check for robustness but only consider the results of the Multi-Stage DCF in my ROE recommendation. The results of the Multi-Stage DCF are higher than those of the Constant Growth DCF, which reflects expectations for faster EPS growth in the near to medium term. Both DCF models produce results that are consistent with estimates from academics and investment managers.

---

[93] *Supra* fn. 85, the U.S. CBO estimates nominal GDP will grow by an average rate of 3.8 percent from 2026 to 2056; *supra* fn. 86, S&P data shows that the Utility sector has grown EPS by 3.43 percent since the data began in 2008.

Table 7: Consolidated Summary of DCF Results

	Cassara Proxy Group	McKenzie Proxy Group	Exelon
Constant Growth DCF			
Growth = GDP	7.27%	7.22%	7.64%
Growth = Utility EPS	6.90%	6.86%	7.27%
Average	7.08%	7.04%	7.46%
Multi-Stage DCF			
Growth = GDP	7.82%	7.76%	8.04%
Growth = Utility EPS	7.57%	7.51%	7.79%
Average	7.70%	7.64%	7.91%

iii. Conclusions

Q. What COE do you estimate for BGE based on your CAPM and DCF analyses?

A. The COE analyses that I conducted for the proxy group yielded estimates of 6.81 percent (CAPM) and 7.70 percent (Multi-Stage DCF), with a range from 6.81 percent to 7.82 percent. The average of the estimates is 7.26 percent, and the midpoint between the low and high model results is 7.32 percent. Across the analyses, the average result for BGE's parent company, Exelon, was similar to the results for the proxy group (average of 7.13 percent vs. the proxy group average of 7.26 percent). Given these results, I conclude that a reasonable estimate of BGE's actual COE is 7.3 percent, and I recommend the Commission adopt this figure as BGE's authorized ROE.

8. Setting an ROE than Better Aligns with BGE's COE Could Provide Significant Savings to Ratepayers

Q. What increase to its revenue requirement did BGE propose?

A. BGE proposed a $156 million increase to its revenue requirement, from a base of $1.716 billion, a 9.09 percent increase.[94] The company calculated its proposed revenue increase using an adjusted rate base of $6.055 billion, its proposed ROE of 10.40 percent, and operating income of $3.55 million in the twelve months ending March 31, 2026.[95]

Q. How does BGE's revenue requirement at BGE's requested ROE compare to the revenue requirement at the ROE you are recommending?

A. Using BGE's proposed rate base, BGE's proposed 10.4 percent ROE would require the retail revenue requirement to increase from $1.716 billion to $1.872 billion, a $156 million rate increase. If the Commission were to instead adopt my ROE recommendation of 7.3 percent, BGE's total retail revenue requirement would be set at approximately $1.738 billion; this would represent a $22 million increase in BGE's revenue relative to the year ending March 31, 2026 and a $135 million decrease relative to BGE's proposal.[96]

Q. What is the impact of one basis point on BGE's revenue requirement?

A. Each basis point in additional ROE increases BGE's retail revenue requirement by approximately $433,000 each year.

---

[94] BGE Exhibit JCF-5E.
[95] BGE Exhibit JCF-5E.
[96] BGE Exhibit JCF-5E. Results calculated by updating the "Cost of Common Equity" field (Line 31) and comparing the changes to the Rev. Rqmt. Deficiency (Line 46) in BGE Exhibit JCF-5E.

Q. If the Commission were to adopt BGE's proposed ROE, how would customer bills be impacted?

A. It is well established that customer bills increase with a utility's authorized ROE. To isolate the bill impacts of ROE, I used BGE's requested rate base of $6.055 billion, though that does not mean I endorse that figure. In this case, BGE is requesting a rate increase of roughly $156 million, based on an ROE of 10.4 percent. If BGE's revenue requirement was instead calculated using its currently approved ROE of 9.5 percent, the necessary rate increase would be $117 million, based on a total revenue requirement of $1.833 billion. The difference between these figures—$39 million—is the amount BGE is requesting that would pay for higher returns for its shareholders.

Table 8: BGE's Total Retail Revenue Requirement at Different ROEs[97]

ROE	Rev. Rqmt. Deficiency/(Excess) *$000s*	Total Rev. Rqmt. *$000s*	Difference vs. 9.5% ROE *$000s*
10.40%	$156,115	$1,872,893	$39,154
10.00%	$138,623	$1,855,401	$21,662
9.50%	$116,960	$1,833,739	$ -
9.00%	$95,296	$1,812,074	($21,665)
8.50%	$73,625	$1,790,403	($43,336)
8.00%	$51,947	$1,768,726	($65,013)
7.50%	$30,265	$1,747,044	($86,695)
7.30%	$21,922	$1,738,701	($95,038)
7.00%	$8,573	$1,725,352	($108,387)

[97] BGE Exhibit JCF-5E. Results calculated by updating the "Cost of Common Equity" field (Line 31) and comparing the changes to the Rev. Rqmt. Deficiency (Line 46) in BGE Exhibit JCF-5E.

Q. If the Commission were to adopt your recommended ROE for BGE, how would customer bills be impacted?

A. Whereas BGE's proposed 10.4 percent ROE requires the retail revenue requirement to increase by $156 million, my ROE recommendation of 7.3 percent would require total revenues to increase only $22 million, saving ratepayers $134 million annually relative to BGE's proposal.[98] Of that, residential rate classes would save $81.8 million annually, which translates to just over $9 per customer each month, as shown in Table 9.[99]

Table 9: Impact of Reducing BGE's ROE on Retail Rates and Distribution Bills[100]

ROE	Increase in Res. Rev. Rqmt. *$000s*	Total Res. Rev. Rqmt. *$000s*	Avg. Distribution Bill *$/month*	Change in Avg. Bill *$/month*	Change vs. 9.5% ROE *$/month*
10.40%	$95,267	$1,142,911	$78.45	$10.72	$2.69
10.00%	$84,593	$1,132,236	$77.71	$9.51	$1.49
9.50%	$71,374	$1,119,017	$76.81	$8.03	$ -
9.00%	$58,153	$1,105,797	$75.90	$6.54	($1.49)
8.50%	$44,929	$1,092,572	$74.99	$5.05	($2.97)
8.00%	$31,700	$1,079,344	$74.08	$3.57	($4.46)
7.50%	$18,469	$1,066,113	$73.18	$2.08	($5.95)
7.30%	$13,378	$1,061,021	$72.83	$1.50	($6.52)
7.00%	$5,232	$1,052,875	$72.27	$0.59	($7.44)

[98] This calculation accepts all other aspects of BGE's application to create an apples-to-apples comparison, but should not be construed as an endorsement of the other items in BGE's proposal.
[99] BGE Exhibit JCF-5E for total Revenue Requirement impacts. BGE's Cost of Service model provided in Staff DR 05-01 – Attachment 1 was used to estimate the Residential classes' (Residential Service (R) and RES Large Time of Day (TL)) allocation of Rate Base and Revenue Requirement, as well as the number of customers.
[100] *Supra* fn. 97.

An ROE of 7.3 percent would meet BGE's cost of equity, enabling the company to attract needed capital and providing investors with an opportunity to make a fair return, while also saving BGE's ratepayers from substantial rate increases.

9. Addressing Problems with BGE's Analysis

Q. Why are your COE estimates significantly lower than Mr. McKenzie's estimates?

A. Mr. McKenzie estimated BGE's COE to be between 9.9 percent and 10.9 percent and he recommended setting BGE's ROE at 10.4 percent.[101] In comparison, I estimate BGE's COE to be 7.3 percent. The difference between our results stems from the fact that Mr. McKenzie (1) used assumptions that violate basic principles of finance, (2) adjusted inputs inappropriately to mechanically increase his COE estimates, and (3) used models that do not actually measure the COE.

In this section, I discuss problems I have identified in Mr. McKenzie's DCF, CAPM, ECAPM, Risk Premium, and Expected Earnings models.

i. BGE's DCF Analysis

Q. Please summarize Mr. McKenzie's DCF analysis.

A. Mr. McKenzie uses the Constant Growth version of the DCF model. He uses Value Line's estimate of dividends over the next twelve months, divided by the prior 30-day average stock price to estimate expected dividend yield for each proxy group company.[102] Mr. McKenzie then uses EPS growth forecasts from IBES, S&P

[101] McKenzie Direct at 3.
[102] McKenzie Direct at 42.

Capital IQ, Value Line, and Zacks, along with a "sustainable growth rate" that he calculates, to estimate the growth term of the DCF for each proxy group company.[103] Mr. McKenzie excludes any DCF results below 7.7 percent or above 12.5 percent because he states these results would be "implausibly low or high."[104]

Q. Are the inputs and assumptions that Mr. McKenzie uses in his DCF reasonable?

A. No. The most important mistake that Mr. McKenzie makes in his DCF is using 3 to 5 year analyst forecasts as an input in a model requiring a perpetual growth rate.

Q. Please elaborate on Mr. McKenzie's misapplication of analysts' EPS growth forecasts.

A. Using 3 to 5 year analyst forecasts as an input to a Constant Growth DCF analysis is an inappropriate choice for three reasons: (1) a 3 to 5 year forecast is not sufficiently long-term in nature to approximate a perpetual growth rate; (2) the 6.6 percent growth rate Mr. McKenzie calculates is roughly double historical growth rates, which makes it an unrealistic perpetual growth rate; and (3) he is using a form of the DCF model that is inconsistent with the growth he projecting. Said differently, the Constant Growth form of the DCF model produces valid results when future growth will be similar to historic growth. If one believes that a utility's earnings growth in the next 3 to 5 years will be much higher than it has been historically, one should use a Multi-Stage DCF.

[103] McKenzie Direct at 43-44.
[104] McKenzie Direct at 45, 47.

Q. Why are 3 to 5 year forecasts too short to approximate a perpetual growth rate?

A. In his testimony, Mr. McKenzie acknowledges that this model assumes "a constant growth rate for both dividends and earnings" and that this assumptions "extend[s] to infinity."[105] Textbooks on implementing the DCF are littered with warnings about extrapolating patterns observed over 3 to 5 years into the future because the results can be highly misleading.[106] Mr. McKenzie ignores those warnings because "all financial models used to estimate the cost of equity—including the DCF approach—are necessarily based on simplifying assumptions, and there is no single financial model that can be considered failsafe" and because "implementation of the DCF model is not a theoretical exercise." [107] Importantly, he admitted that he neither performed any analysis nor is aware of any research that verifies how much deviation from the simplifying assumptions of the model is acceptable before the model no longer produces reasonable estimates.[108]

---

[105] McKenzie Direct at 40, fn 72.
[106] *Supra* fn. 84*; see also, supra* fn. 88*; see also, supra* fn. 90*; see also,* Morin (2006) at 308 ("the problem is that from the standpoint of the DCF model that extends into perpetuity, analysts' horizons are too short, typically five years. It is often unrealistic for such growth to continue.").
[107] BGE Response to OPC Data Request 03-05.
[108] BGE Response to OPC Data Request 03-05.

Q. Why is the average growth rate that Mr. McKenzie calculates unrealistic?

A. The average EPS growth estimate that Mr. McKenzie uses in his analysis is 7.0 percent.[109] His estimate is not supported by data showing that this growth can be sustained perpetually.

To assess the reasonableness of a 7.0 percent growth forecast, I analyzed historical growth, a common starting point for estimating future growth rates.[110] I analyzed the compound growth rate in annual EPS and DPS for each proxy group company from 2000 through 2025. Over that time, the proxy group companies have grown earnings and dividends at compound average rates of 2.77 percent and 2.42 percent, respectively.[111] In other words, the growth rate that Mr. McKenzie relies upon in his DCF model is more than double the growth rate his proxy group companies have actually achieved historically.

Q. Is a Constant Growth DCF analysis appropriate if the proxy group companies are expected to grow earnings at 7 percent for the next 3 to 5 years?

A. No. One of the fundamental premises of the Constant Growth DCF is the company's growth is stable (i.e., the future looks like the past).[112] Stable growth enables the extrapolation of past growth into the future. If Mr. McKenzie thinks

---

[109] BGE Exhibit AMM-5. Adjusted to reflect the exclusion of certain estimates for Consolidated Edison, Fortis Inc., and OGE Energy Corp. in Mr. McKenzie's results.

[110] *See, e.g.,* Morin (2006) at 283 ("historical growth rates in dividends, earnings, and book value are often used as proxies for investor expectations in DCF analysis. Investors are certainly influenced to some extent by historical growth rates in formulating their future growth expectations.").

[111] See Attachment DMC-6 for detail on each of the proxy group companies; for robustness, I also analyzed growth rates from the first period data was available through 2025. Those growth rates were even lower than growth rates over the past 25 years: 1.45% (EPS) and 1.09% (DPS).

[112] *See, e.g.,* Morin (2006) at 256; *see also* A. Damodaran (2012) at 321.

the future will look dramatically different (e.g., 7 percent per annum growth vs. less than 3 percent per annum growth), then the Constant Growth DCF is not a conceptually valid model choice and he should run a Multi-Stage DCF as I did.

ii. BGE's CAPM Analysis

Q. Please summarize the CAPM analysis that Mr. McKenzie conducted.

A. Mr. McKenzie uses the average yield on 30-year Treasury bonds over the six months ending April 30th for his risk-free rate. He calculates his ERP by subtracting the risk-free rate from his estimate of expected returns for the S&P 500 Index. The latter is calculated by running a Constant Growth DCF model on the dividend paying firms in the S&P 500 Index, removing those whose forecasted growth rates are either negative or greater than 20 percent, which produces an estimated market return of 12.7 percent; net of the risk-free rate, this yields an estimated ERP of 7.9 percent. For his beta terms, Mr. McKenzie uses exclusively Value Line betas. Finally, Mr. McKenzie performs a size adjustment, sourced from Kroll.[113]

Q. Does Mr. McKenzie use reasonable inputs and assumptions?

A. No. Mr. McKenzie makes several choices that stray from established best practices. Those choices increase his overall estimate of the COE. The primary issues are Mr. McKenzie's use of adjusted betas, calculation of the ERP, and size adjustment.

[113] McKenzie Direct at 48-51.

Q. Please explain the problems with Mr. McKenzie's beta estimates.

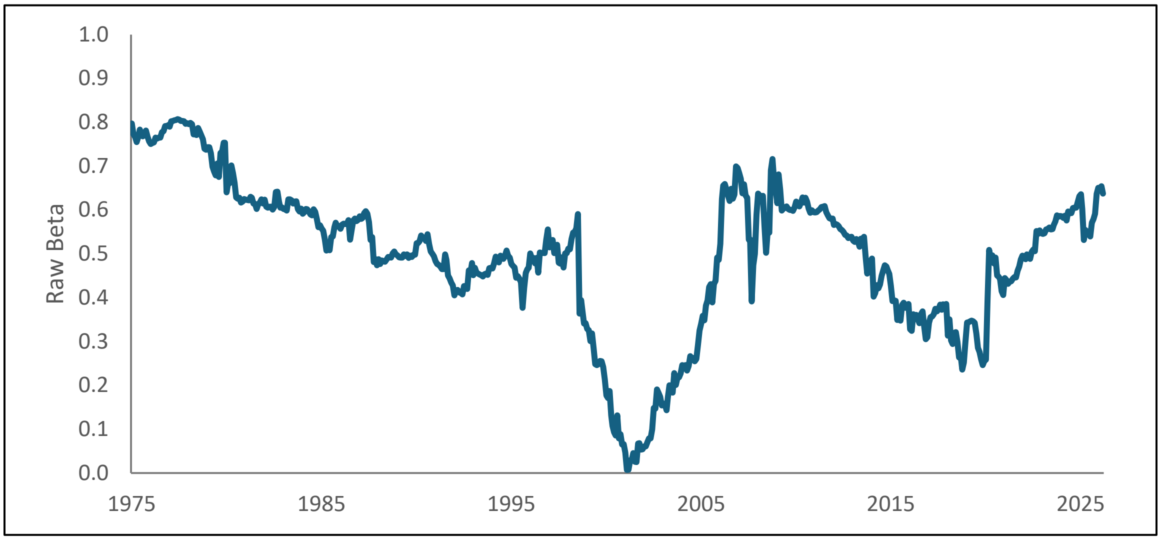
A. The primary problem with Mr. McKenzie's beta is that he uses "adjusted" betas from Value Line.[114] The adjustment that Value Line makes to beta is based on research by Marshall Blume from 1971 showing that betas had historically reverted towards a mean of 1.0.[115] For stocks with low betas, like utilities, this adjustment will increase the estimate of beta. This will produce larger adjustments the further the raw beta estimate is from 1.0. For example, I use beta estimates from Yahoo! Finance and Zacks, for a proxy group average of 0.44. Applying the Blume adjustment would increase the beta estimate to 0.62, a 42 percent increase. These substantial increases in beta are not justified by Blume's research.[116]

Blume's original 1971 paper looked at stocks generally and did not investigate whether stocks across different sectors may behave differently. Intuitively, it makes sense that utility stocks would have more stable betas than those of non-regulated firms, as utilities are more insulated from competition, the business cycle, and changes in consumer preference. Multiple academic researchers have found that utility betas tend to be stable below 1.0—i.e., do not converge towards 1.0—and tend to be among the lowest of any sector; these researchers have concluded that using adjusted betas in a ratemaking context is

[114] McKenzie Direct at 49-50, BGE Exhibit AMM-7.
[115] M. Blume, *On the Assessment of Risk*, 26:1 The J. of Fin. at 1-10 (1971) https://onlinelibrary.wiley.com/doi/10.1111/j.1540-6261.1971.tb00584.x.
[116] Specifically, the adjustment used by providers like Bloomberg is: $\beta_{adj} = \left(\frac{2}{3}\beta_{raw}\right) + \frac{1}{3}$.

inappropriate.[117] That utility betas do not revert to 1.0 can also be seen graphically, below.

Figure 10: Betas for the Utility Sector, Last 50 Years[118]



Ample evidence demonstrates that utility betas do not revert towards 1.0. Consequently, an upwards adjustment—based on the premise that they do revert towards 1.0—is inappropriate for utilities. Had Mr. McKenzie used unadjusted betas, his proxy group average beta would have been roughly 0.59, which illustrates that this adjustment alone explains about half the difference in our beta terms. Adjusted betas directly lead to CAPM estimates that are 1 to 3 percentage points higher, depending on the ERP used.

[117] R.A. Michelfelder & P. Theodossiou, *Public Utility Beta Adjustment and Biased Costs of Capital in Public Utility Rate Proceedings*, 26:9 The Electricity J. at 60-68 (2013), https://www.sciencedirect.com/science/article/abs/pii/S1040619013002340?via%3Dihub; *see also* L. Baele and J.M. Londono, *Understanding Industry Betas*, Journal of Empirical Finance 22:30-51 (2013), https://linkinghub.elsevier.com/retrieve/pii/S0927539813000108. Baele and Londono find that utilities are in the lowest 30% of betas 92% of the time.

[118] French (*Current Research Returns Data Library*); analysis by author, betas calculated.

Q. Please explain the problems with Mr. McKenzie's estimate of the Market Risk Premium.

A. Mr. McKenzie's Market Risk Premium (MRP, another term for Equity Risk Premium) is based on a Constant Growth DCF that he uses to estimate the expected return for the S&P 500 Index. Mr. McKenzie's analysis repeats the mistakes he made in running the Constant Growth DCF on the proxy group companies. Using this type of DCF model with all companies in the S&P 500, when many of those companies are less mature than utility companies or are in industries experiencing extremely rapid short-term growth, amplifies the other problems with his analysis. He estimates that investors require a 12.7 percent return from the S&P 500, higher than the estimates from any investment manager, academic, or survey I am aware of.[119]

Q. Do you agree with the size adjustment that Mr. McKenzie makes to his CAPM model?

A. No, I do not. To begin with, the Commission has repeatedly rejected the use of a size adjustment in the CAPM model, a fact which Mr. McKenzie acknowledges.[120] Mr. McKenzie states that his analysis differs from those rejected by the Commission in the past because he "is not proposing to include a business risk premium," his "recommendation does not include any adjustment related to the

[119] McKenzie Direct at 49.
[120] *See, e.g.*, Md. Pub. Serv. Comm'n, Order No. 89678, Application of Baltimore Gas and Electric Company for an Electric and Gas Multi-Year Plan (Case No. 9645, Dec. 16, 2020) at 153; Md. Pub. Serv. Comm'n, Order No. 89072, Application of the Potomac Edison Company for Adjustments to its Retail Rates for the Distribution of Electric Energy (Case No. 9490, March 22, 2019) at 75-76; McKenzie Direct at 51.

relative size of BGE," and the "size adjustment is specific to the CAPM."[121] Given that Mr. McKenzie's recommendation ultimately incorporates his CAPM results, his claim to not include adjustments related to the size of BGE in his overall recommendation is simply untrue. He has not provided any new information or analysis to justify the validity of a size adjustment, but has simply tweaked the way in which he makes such an adjustment. As such, the Commission should continue to reject size adjustments such as Mr. McKenzie's.

iii. BGE's Empirical Capital Asset Pricing Model

Q. Please summarize Mr. McKenzie's Empirical Capital Asset Pricing Model ("ECAPM") analysis.

A. The ECAPM is premised on the idea that low-beta securities earn higher returns than the CAPM would predict, and thus an adjustment is needed to better represent expected returns for low-beta securities moving forward. Mr. McKenzie adopts a formula put forth in *New Regulatory Finance* which assigns a standard 25 percent weight to the ERP, and a 75 percent weight to the ERP times Beta. On top of this adjustment, Mr. McKenzie repeats the size adjustment that he made in his CAPM analysis. His ECAPM model estimates the COE for BGE to be 11.3 percent.[122]

Q. Do you support the use of the ECAPM model?

A. No, I do not. The ECAPM formula is neither supported by research nor used by professional investors. Although Mr. McKenzie states that replicating the

[121] McKenzie Direct at 52.
[122] McKenzie Direct at 52-54.

expectations of investors is a key consideration to running a COE model,[123] he also admits that he "is not aware of an investment analyst report that specifically utilizes the ECAPM as the basis to value a common stock."[124]

Further, the ECAPM model has been rejected by this Commission in the past.[125] Mr. McKenzie offers no reason or analysis that should deviate from its prior rejections of this model's usage. As such, I recommend Mr. McKenzie's ECAPM model be given no weight.

iv. BGE's Utility Risk Premium Analysis

Q. Please explain Mr. McKenzie's Utility Risk Premium Analysis.

A. Mr. McKenzie's Utility Risk Premium analysis estimates the COE as the sum of 30-year Treasury yields and an ERP, which he calculates as the difference between authorized ROEs and the bond yields on public utility bonds at the time the ROE was approved. His dataset includes ROE decisions for vertically integrated electric utilities from 1974 through 2025.[126]

Mr. McKenzie regresses his "risk premium" on 30-year Treasury yields. The results of his regression show that the "risk premium" for utilities increases as bond yields decrease, and vice versa. He estimates the current COE for utilities by

---

[123] BGE Response to Data Request OPC 03-05.
[124] BGE Response to Data Request OPC 03-08.
[125] *See, e.g.,* Md. Pub. Serv. Comm'n, Order No. 91181, *Potomac Elec. Power Co.'s Application for Adjustments to its Retail Rates for Distribution of Electric Energy* (Case No. 9702, Jun. 10, 2024) at 147.
[126] McKenize Direct at 55-57, BGE Exhibit AMM-9.

entering the current average yield on public utility bonds into his regression equation.[127] He estimates a "risk premium" for utility stocks over bonds that ranges from -0.40 percent to 6.32 percent, averaging 3.91 percent.[128] He reports an overall result from the Risk Premium analysis of 10.49 percent.[129]

Q. Is Mr. McKenzie's Risk Premium Analysis an analytically sound assessment of BGE's COE?

A. No. Mr. McKenzie's Utility Risk Premium Analysis substitutes past regulatory decisions for investors' required returns even though regulatory decisions *are not* the same as market prices. Using past regulatory decisions to inform current regulatory decisions is circular and creates a feedback loop that leads authorized ROEs to drift from what is economically justified, which increases the risk of unfair rates.[130] For the relationship between authorized ROEs and bond yields to represent a true risk premium, one would need to assume that authorized ROEs always equaled the cost of equity; numerous academic researchers and my testimony demonstrate this is not the case.

FERC has rejected analyses like Mr. McKenzie's Risk Premium Analysis precisely because they are circular and do not measure the COE by stating that the model was subject to "direct and acute" circularity.[131] Multiple state utility commissions have also found that the Risk Premium Model "does not provide

[127] McKenize Direct at 55-57; BGE Exhibit AMM-9.
[128] BGE Exhibit AMM-9.
[129] McKenzie Direct at 57.
[130] Werner and Jarvis (2025).
[131] 189 FERC ¶61,036.

information about the returns investors require,"[132] and that "the degree of influence of authorized ROEs from other state commissions in that analysis" makes the Risk Premium Model inappropriate.[133]

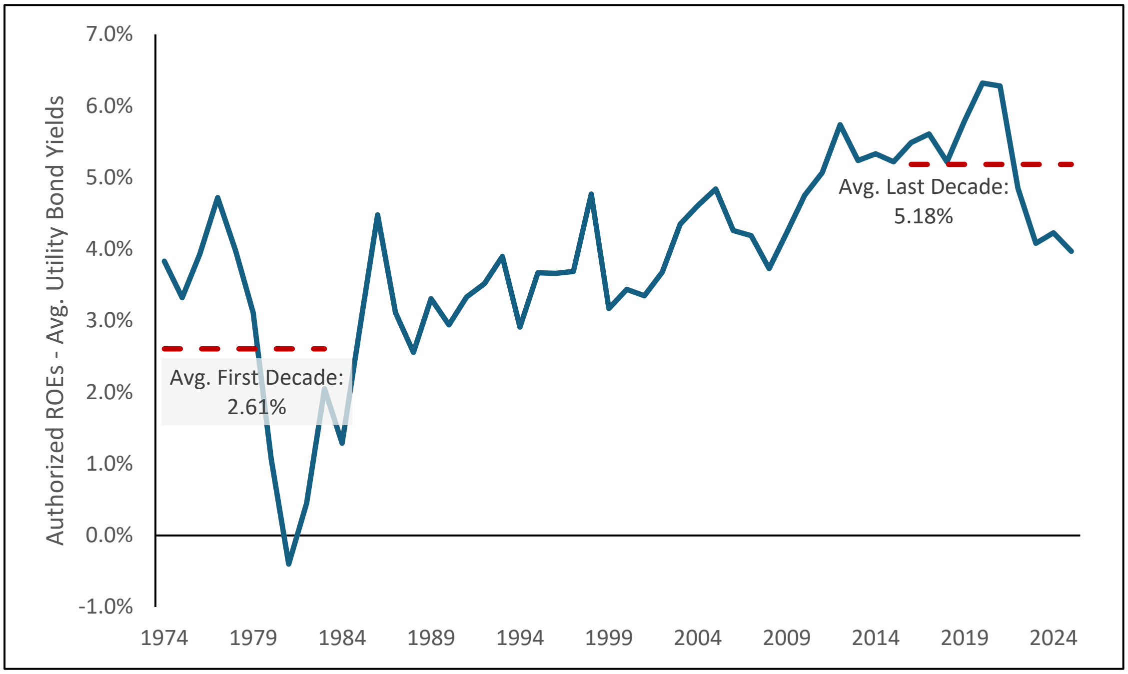
Q. How does Mr. McKenzie's Risk Premium Analysis relate to research you cited earlier in your testimony?

A. Recall that in Section 6, I discussed research from the University of California, Berkeley showing that over the past 40 years, interest rates have almost universally fallen, while authorized have lagged behind, creating a gap between the market-wide cost of capital and ROEs. Plotting the data from Mr. McKenzie's Risk Premium analysis chronologically, as I've done in Figure 11 below, shows that the difference between ROEs and bond yields that Mr. McKenzie analyzes is simply a re-arrangement of data showing the gap between authorized rates and Treasury yields has increased over time. In the first decade of Mr. McKenzie's data, ROEs were set 2.6 percent above the utility bond yields on average. In the most recent decade, ROEs were set 5.2 percent higher than utility bond yields on average, doubling the spread between bond yields and ROEs.

[132] Minn. Pub. Utils. Comm'n, In the Matter of the Application of Northern States Power Company, d/b/a Xcel Energy, for Authority to Increase Rates for Electric Service in the State of Minnesota (Case No. E-002/GR-21-630, July 17, 2023) at 89, https://efiling.web.commerce.state.mn.us/documents/%7BC0236589-0000-C115-A5A9-E96843D1FFF6%7D/download?contentSequence=0&rowIndex=241.

[133] Utah Pub. Serv. Comm'n, Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations (Docket No. 24-035-04, Apr. 25, 2025) at 25, https://pscdocs.utah.gov/electric/24docs/2403504/3395032403504,2303540,and2303544o4-25-2025.pdf.

Figure 11: Avg. Authorized Electric ROEs minus Utility Bond Yields[134]



Correlation does not equal causation, and there is no reason to believe that interest rates are a causal factor in this increasing "risk premium." Rather, the data reflects the stickiness of authorized ROEs. Over this time, Mr. McKenzie's data shows that utility bond yields fell 7 percent, while ROEs fell just 4.4 percent.[135] Mr. McKenzie's Risk Premium analysis is just another way to show that the gap between authorized ROEs and bond yields has increased almost linearly for four decades as interest rates fell from their late 1970's peaks.

[134] Data from BGE Exhibit AMM-9, analysis by author.
[135] Data from BGE Exhibit AMM-9. Utility bond yields fell from 11.39% to 4.43%, while ROEs fell from 14.00% to 9.62%.

Q. Is the type of Risk Premium analysis that Mr. McKenzie presents a method that is commonly used by investors?

A. No, I am not aware of any investors who estimate expected returns using the type of risk premium analysis that Mr. McKenzie conducted in his testimony. Although Mr. McKenzie writes that "this method is routinely referenced by the investment community and in academia and regulatory proceedings," he clarified in discovery that "this method" refers to the risk premium approach broadly (e.g., the CAPM is a risk premium method), and "not specifically to the methodology presented in Company Exhibit AMM-9."[136]

Q. What is your recommendation with respect to Mr. McKenzie's Utility Risk Premium analysis?

A. I recommend the Commission reject all Risk Premium analyses, including Mr. McKenzie's, that use past regulatory decisions as model inputs, because such models are circular.

v. BGE's Expected Earnings Analysis

Q. Please explain Mr. McKenize's Expected Earnings Approach.

A. Mr. McKenize's Expected Earnings analysis takes the Value Line forecast of the expected return on book equity for each proxy group company, and adjusts them to reflect the return earned on the average book equity value throughout the year, rather than the year-end balance. His Expected Earnings model estimates a return of 10.4 percent.[137]

---

[136] McKenzie Direct at 55 (emphasis added), BGE Response to Data Request OPC 03-09.
[137] McKenzie Direct at 58-60.

Q. What is your response to Mr. McKenzie's Expected Earnings analysis?

A. The Expected Earnings analysis is flawed in at least two ways.

Issue One: The analysis is based on book returns, not market returns, and thus does not provide information about investors' required returns.

Recall from Sections 3 and 4 that market returns—what investors earn in dividends and capital appreciation—are not well explained by the book accounting returns a utility earns. The Expected Earnings analysis is explicitly based on book returns. Recall that the comparable earnings test from *Hope* is concerned with "[t]he return to the equity owner."[138] As Dr. Morin states, "the [Expected] Earnings standard ignores capital markets,"[139] and Mr. McKenzie testifies that the approach "avoids the complexities and limitations of capital market methods and instead focuses on the returns earned on book equity."[140] Because the Expected Earnings test does not focus on market returns, it cannot be a test of what equity owners expect to receive, making it irrelevant to the comparable earnings test.

Issue Two: The Expected Earnings analysis is circular.

The Expected Earnings analysis that Mr. McKenzie conducts repeats the mistakes of the Risk Premium analysis: it substitutes regulatory decisions for investors' required returns, which creates a circular analysis.[141]

---

[138] *Hope* at 603.
[139] Morin (2006) at 393.
[140] McKenzie Direct at 58.
[141] *See, e.g.,* Myers (1972) at 63 ("Basing current regulatory decisions partly on past decisions leads to a dangerously arbitrary standard.").

Q. Has Mr. McKenzie evaluated whether there is a relationship between the forecasts he uses of return on book equity and investors' returns, expected or realized?

A. No, he has not. To begin with, he states that "[i]nvestors' rate of return on common equity is not observable," so it is not possible to analyze its relationship with authorized ROEs or book returns.[142] This is a surprising defense given the total return on common equity is widely published and available from sources like Yahoo! Finance, Morningstar, S&P, and others. Then, he writes "[c]omparisons of projected returns with actual realized returns are irrelevant in evaluating investors' expectations, which are forward-looking,"[143] undermining his claim that realized returns are not observable and ignoring that investors' forward-looking expectations are influenced by historical realized returns.[144]

Finally, when asked in discovery whether "returns on earned on book equity [are] synonymous with the expected return on common equity," Mr. McKenzie refers to his direct testimony and states that "expected earned returns on book equity provide a meaningful guide to investors' expected return on common equity for utilities because the allowed ROE is applied to the book value of a utility's rate base."[145] It is unclear how he arrived at this conclusion without conducting any analysis or referring to any authoritative academic sources, and

142 BGE Response to Data Request OPC 11-01.
143 BGE Response to Data Request OPC 11-02.
144 *See, e.g.,* R.A. Morin (2006) at 249-250, 283.
145 BGE Response to Data Request OPC 11-02.

given that he earlier stated that investors' return on common equity is unobservable.

Q. Please summarize your assessment of the Expected Earnings model.

A. Mr. McKenzie's Expected Earnings analysis does not measure the cost of equity, is circular, and lacks empirical support. Therefore, it should be given no weight.

vi. Reducing BGE's ROE is Highly Unlikely to Increase Customers' Rates

Q. Does BGE claim that there are risks associated with authorizing an ROE that is too low?

A. Yes, it does. The testimony of company witness Cloyd discusses the consequences if BGE's ROE were set too low, stating that this would "ultimately harm consumers."[146] The reason an insufficient ROE could harm consumers, according to Mr. Cloyd, is that it would adversely affect BGE's credit metrics, increasing "BGE's cost of borrowing and, by extension, the cost of service borne by customers" and impairing the company's ability to attract capital. [147] He concludes that "any near-term rate reduction achieved through an inadequate return or an unsound capital structure would be illusory, as it would be offset – and likely exceed – by higher long-term financing costs" and a deterioration in BGE's system, reliability, and quality of service.[148]

[146] Cloyd Direct at 15.
[147] Cloyd Direct at 16.
[148] Cloyd Direct at 16.

Q. Do you agree with Mr. Cloyd about the risks to BGE's ratepayers if the company's ROE were lowered?

A. I do not. While I agree with the company's witnesses that "an inadequate return" could have adverse effects on both the company and its customers, BGE's current ROE is, as my testimony has demonstrated, more than sufficient to meet investors' cost of equity. In other words, reducing BGE's ROE down to its cost of equity would have the near-term impact of reducing rates—as Mr. Cloyd acknowledges—but is highly unlikely to increase the cost of service borne by customers.

Q. Has the company conducted any analysis to support its claims about the consequences of lowering its ROE?

A. No, it has not.[149]

Q. Has the company provided any examples of a lower ROE raising future borrowing costs by an amount such that the overall ROR was higher than it had been initially?

A. No. The company confirmed in discovery that it is not aware of any such examples.[150] Nonetheless, despite being unaware of such an event ever occurring and without performing any analysis, the company maintains that "generally accepted utility finance principles" support its position.[151]

---

[149] BGE Response to Data Request OPC 11-07.
[150] BGE Response to Data Request OPC 03-14 and BGE Response to Data Request OPC 11-07.
[151] BGE Response to Data Request OPC 03-14.

Q. Have you conducted any analysis to verify whether the company's claims about the consequences of lowering its ROE are credible?

A. Yes, I have. In short, the company's position that lowering its ROE could ultimately raise the cost of service borne by customers is not credible and should be disregarded as speculative fearmongering. To begin with, I evaluated how much BGE's cost of debt would need to rise to offset the impact that lowering its ROE would have on the company's overall revenue requirement. Then, I examined historical spreads for bond yields to analyze how likely it would be that such an increase in BGE's cost of debt could occur.

Q. If the Commission were to adopt your recommended 7.3 percent ROE, how much would BGE's cost of debt need to rise for its revenue requirement to stay the same?

A. Because of the impact of taxes, customers pay more than $1 in rates to support $1 in after-tax return on equity. Thus, the cost of debt would need to rise faster than ROE falls for the cost of service borne by BGE's customers to stay the same. Table 10 below shows how much the embedded cost of debt would need to increase for a given reduction in BGE's ROE (relative to the company's proposal) such that the overall revenue requirement stays the same. For example, if BGE's ROE were reduced to my recommendation of 7.3 percent, the embedded cost of debt would need to rise by 4.70 percent to 9.42 percent for BGE's proposed revenue requirement to stay the same. Put differently, as long as BGE's cost of debt stays below 9.42 percent, customers would save money even after paying rates to support higher interest rates if BGE's ROE was set at 7.3 percent.

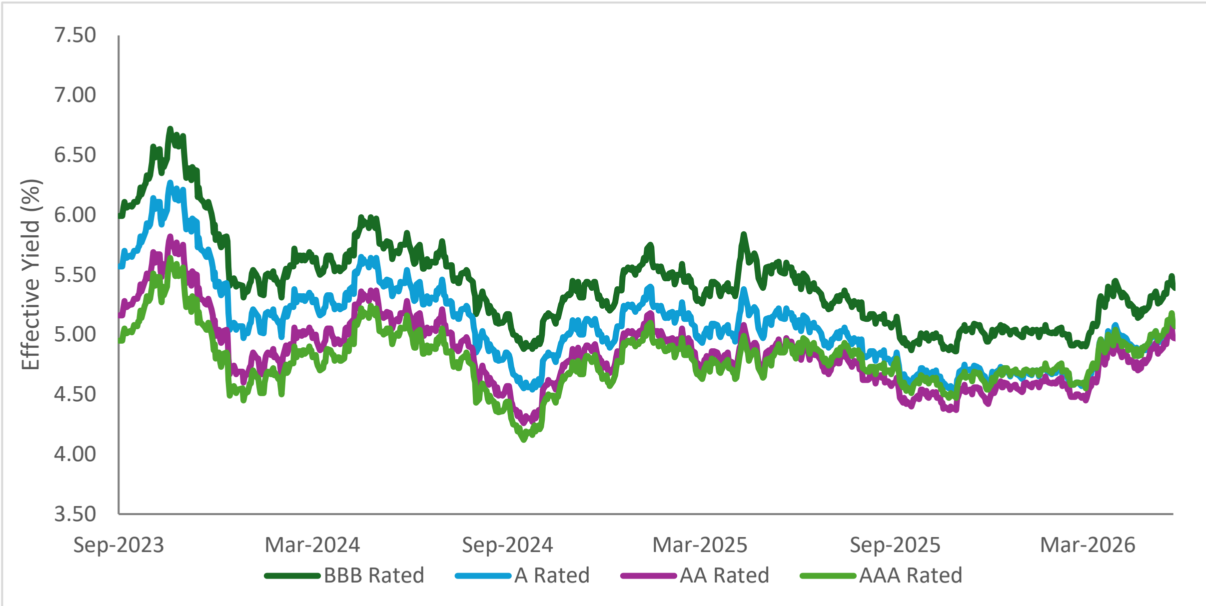
Table 10: For each 1% Reduction in ROE, BGE's Cost of Debt Needs to Rise About 1.5% for its Revenue Requirement to Stay the Same

ROE	ROE Decrease from Proposed	Cost of Debt to Maintain Rev. Rqmt.	Increase in Cost of Debt from Current
10.40%	0.00%	4.72%	0.00%
10.00%	-0.40%	5.34%	0.62%
9.50%	-0.90%	6.10%	1.38%
9.00%	-1.40%	6.85%	2.13%
8.50%	-1.90%	7.61%	2.89%
8.00%	-2.40%	8.36%	3.64%
7.50%	-2.90%	9.11%	4.39%
7.30%	-3.10%	9.42%	4.70%
7.00%	-3.40%	9.87%	5.15%

Q. How likely is it that BGE's cost of debt would rise by more than 4.5 percent if its ROE were set at 7.3 percent?

A. Highly unlikely. After a credit rating downgrade, a utility would typically need to pay a higher interest rate to borrow capital. However, rates rise in relatively small increments between each credit rating notch. Figure 12 below shows the average effective yield for investment grade corporate bonds (rated AAA through BBB) over the past three years. The difference in yields between bonds (called a "spread") rated A and BBB has been 0.34 percent on average, 0.75 percent at most, and was 0.32 percent at the end of August 2026. If BGE's credit rating were to fall because its ROE is set at a level that more accurately measures its COE, it is reasonable to conclude that its interest rate on new issuances could rise approximately 0.3 percent to 0.7 percent.

Figure 12: Corporate Bond Yields by Credit Rating[152]



The takeaway from this data is that if BGE's credit rating decreased from A- to BBB+ or BBB, its cost to issue new debt is likely to rise only moderately. Consequently, the savings that customers realize from a lower ROE are likely to exceed the additional cost of debt that customers incur from a credit downgrade.

Q. Are there any other reasons to be skeptical that lowering BGE's ROE would increase the cost of service borne by ratepayers?

A. Yes. It is important to remember that the embedded cost of debt considers the cost of *all* of BGE's debt, not just new issuances. Changes in the authorized ROE, on the other hand, impact the return on all of BGE's equity capital immediately. Even in the unlikely event that BGE's cost of debt were to increase significantly, the overall effect on BGE's embedded cost of debt would be small for several years.

[152] ICE Data Indices, LLC, ICE BofA AAA US Corporate Index Effective Yield, AA US Corporate Index Effective Yield, Single-A US Corporate Index Effective Yield, and BBB US Corporate Index Effective Yield. Federal Reserve Bank of St. Louis (accessed September 18, 2026).

In summary, I agree with the company's argument that, *all else equal*, an increase in the cost of debt would increase the cost of service borne by consumers. However, if the reason that borrowing costs increase is that the company's ROE was reduced, *all else is not equal*. In this case, the cost of debt would need to increase by more than ROE was decreased. Given the spread in bond yields from one credit rating to the next—both currently and historically—it is highly unlikely that BGE's cost of new issuances would increase by multiple percentage points, even if its credit rating were reduced. Further, such increases to the cost of new issuances would not impact the cost of all outstanding debt, limiting the risk to ratepayers. In other words, there is very little possibility that lowering BGE's ROE would raise the overall ROR borne by customers in both the short and long term.

10. Developing an Overall Rate of Return

i. Capital Structure

Q. What capital structure does BGE propose?

A. BGE is proposing a capital structure with 52 percent common equity and 48 percent debt. The company states that its actual equity ratio was 52.7 percent as of March 31, 2026, and that after adjusting for known and measurable changes that occurred after the end of the test year, the adjusted equity ratio is 52 percent.[153]

[153] Cloyd Direct at 13.

Q. What equity ratio did the Commission authorize in BGE's prior rate case?

A. In BGE's most recent rate case, Case No. 9692, the Commission authorized a capital structure of 52 percent equity and 48 percent long-term debt.[154]

Q. Does BGE's proposal make any adjustments to their actual capital structure?

A. BGE does not make any explicit adjustments to their capital structure when proposing an overall rate of return. However, the company makes an operating income adjustment that largely erases the impact of a statutorily mandated reduction in the return it can receive for its EmPOWER account by increasing the rate of return it would receive on all other assets. As described in more detail by company witness John C. Frain and in Company Exhibit JCF-6, Operating Income Adjustment 24 adjusts the capital structure used to calculate the rate of return on BGE's regulatory asset balance for EmPOWER Maryland programs, as House Bill 864 mandates that the return for such assets be limited to BGE's cost of debt. The Adjustment reduces the amortization on EmPOWER assets, increasing current operating income and reducing the requested increase to BGE's revenue requirement. However, Operating Income Adjustment 25 seeks to offset Adjustment 24 by adjusting BGE's electric distribution capital structure used to calculate the overall rate of return on BGE's remaining distribution rate base.[155]

[154] Md. Pub. Serv. Comm'n, Order No. 90948, Application of Baltimore Gas and Electric Company for an Electric and Gas Multi-Year Plan (Case No. 9692, Dec. 14, 2023) at 243.
[155] Frain Direct at 88-89.

The effect of this adjustment is to reduce the impact of HB 864 by nearly $7 million, or 91 percent, from $7.629 million to only $672,328.[156]

Q. What is the company's rationale for Operating Income Adjustment 25?

A. Maryland House Bill 864 from the 2024 General Assembly session ("Utility Relief Act") specifies that the return on the remaining balance for EmPOWER programs should be limited to the utility's cost of debt.[157] Operating Income Adjustment 24 reduces the amortization expense that BGE recognizes, increasing operating income, so that the requested revenue requirement does not include an equity return on the remaining balance of EmPOWER program assets. BGE states that this adjustment, which is needed to comply with the Utility Relief Act, should be understood to reduce the amount of debt that is available to finance the remaining assets in BGE's electric distribution rate base. Operating Income Adjustment 25 is premised on the idea that if EmPOWER Maryland is 100 percent debt financed, the remaining rate base should be financed by a higher proportion of equity, increasing the overall rate of return applied to the remaining asset base.[158]

Q. What is the magnitude of Operating Income Adjustment 25?

A. Operating Income Adjustment 24 reduces the revenue requirement that BGE is proposing by $7.63 million.[159] Operating Income Adjustment 25 reduces the

[156] Frain Direct Workpapers: "OIA-24E – Eliminate EmPower Maryland Impact," Frain Direct Workpapers: "OIA-25E – To Reflect Revised Capital Structure."
[157] PUA § 7-222(D)(2).
[158] Frain Direct at 88-89.
[159] Frain Direct Workpapers: "OIA-24E – Eliminate EmPower Maryland Impact." Calculated as the EmPOWER Rate Base times the Rate of Return Difference between an all-debt funded capital structure and BGE's proposed capital structure ($257,768,804 * 2.96%).

amount of debt in BGE's non-EmPOWER rate base, raising the equity ratio that the company applies to its non-EmPOWER rate base from 52 percent to 54.31 percent. Correspondingly, the rate of return that the company applies to its non-EmPOWER rate base rises from 7.68 percent to 7.80 percent, leading to a $6.96 million increase in the company's revenue requirement—largely erasing the impact of House Bill 864.[160]

Q. Do you believe the proposed Operating Income Adjustment 25 is reasonable?

A. I do not. The company is correct that EmPOWER program spending is limited to earning a return equal to its cost of debt. However, EmPOWER assets are still part of the utility's distribution investments, and the company is still able to use equity that would have funded EmPOWER assets for other distribution investments. The debt used for EmPOWER is still part of the Company's capital structure and removing it would artificially increase the Company's equity ratio, and therefore, its rate of return.

Q. Has the Commission issued a ruling on a similar adjustment in the past?

A. Yes. The Commission recently ruled in Potomac Electric Power Company's ("Pepco") most recent rate case that a similar adjustment would be inappropriate. In its application, Pepco reasoned that "[g]iven that a portion of Pepco's capital structure has historically supported EmPOWER program spending, the Company

[160] Frain Direct Workpapers: "OIA-25E – To Reflect Revised Capital Structure." Calculated as the ex-EmPOWER Rate Base times the difference between the company's proposed rate of return and the rate of return at the adjusted capital structure ($5,798,026,000 * 0.12%).

has adjusted its capital structure to remove the associated debt. This results in a higher equity ratio than what the Company has historically proposed."[161] In its Order, the Commission found that it would not be appropriate for ratemaking purposes for Pepco to remove EmPOWER-related debt from its capital structure. The Commission stated that:

> EmPOWER programs are part of Pepco's regulated operations and involve investments made by the Company in furtherance of its utility obligations. The fact that Pepco is permitted to earn a return on investments that have not been approved in a rate case is a benefit to Pepco to incentivize those investments, but Pepco capital used to fund Pepco's EmPOWER investments cannot be meaningfully differentiated from capital used to fund any other investment made by Pepco because money is fungible. *The debt that Pepco asserts is attributable to EmPOWER is therefore an undifferentiated part of Pepco's overall financing structure and should be reflected in the capital structure used to determine the Company's ROR in the same way that debt or equity used to fund any other investment would be*.[162]

The Operating Income Adjustments that BGE proposes are functionally the same as the adjustments that Pepco made in Case No. 9820. Accordingly, I recommend that the Commission reject Operating Income Adjustment 25, which unreasonably increases the company's revenue requirement by $6.96 million.

[161] Potomac Electric Power Company's Application for Adjustments to its Retail Rates for the Distribution of Electric Energy (Case No. 9820), Direct Testimony of Company Elizabeth O'Donnell at 5.

[162] Md. Pub. Serv. Comm'n, Order No. 92607, Potomac Electric Power Company's Application for Adjustments to its Retail Rates for the Distribution of Electric Energy (Case No. 9820, Aug. 28, 2026) at 86 (emphasis added).

ii. Cost of Debt

Q. What cost of debt does the company propose?

A. BGE has proposed a cost of debt of 4.72 percent. The company states that its proposal reflects the weighted average cost of all long-term debt outstanding at the end of the 12-month period ending March 31, 2026, adjusted for known and measurable changes. Specifically, the company adjusted the weighted average cost of all long-term debt to reflect $925 million in long-term debt issued on May 22, 2026, carrying a blended coupon rate of 5.63 percent.[163]

Q. Do you believe the company's cost of debt proposal is reasonable?

A. Yes, I do.

iii. Overall Rate of Return

Q. Please summarize your recommendation to the Commission for BGE's ROE, cost of debt, and capital structure.

A. I recommend that the Commission authorize a return on equity for BGE of 7.3 percent, a cost of debt of 4.72 percent, and a capital structure consisting of 52 percent equity and 48 percent debt. Based on these inputs, I recommend the Commission authorize an overall rate of return of 6.07 percent for BGE.

Table 11: Recommended Capital Structure and Overall Rate of Return

	Capital Amount	Rate of Return	Weighted Rate of Return
Equity	52%	7.30%	3.80%
Long-term Debt	48%	4.72%	2.27%
Total	**100%**		**6.07%**

[163] Cloyd Direct at 14-15.

11. Recommendations & Conclusion

Q. Please summarize your recommendations to the Commission.

A. I recommend the following:

1. The Commission should approve an ROE for BGE of 7.3 percent. I recommend an ROE of 7.3 percent based on the results of my CAPM and DCF models, the capital market assumptions published by investment managers, research from the academic community, and current market conditions.
2. The Commission should accept the Company's proposed cost of debt of 4.72 percent and proposed equity ratio of 52 percent, in line with the equity ratio that it authorized in prior cases.
3. The Commission should give little weight to the results from Mr. McKenzie's models and should reject the framework that BGE used to develop its ROE proposal. BGE's framework has the following three errors which should be corrected:
   - (a) BGE conflates *return on equity*, which represents regulatory decision-making, with the *cost of equity*, which represents price discovery in competitive markets. Conflating the two concepts leads to inaccurate analysis and contributes to an unreasonable ROE recommendation.
   - (b) BGE's analysis fails to distinguish between the return BGE earns as a company, which is an accounting measure, and the return BGE

shareholders earn, which is a market measure. Understanding the difference between the two measures and correctly relying on the market return shareholders earn is necessary to properly evaluate how the returns offered to BGE's investors compare to those offered to investors in other similar utilities.

(c) The inputs and assumptions BGE uses to estimate the cost of equity are not suitably grounded in asset pricing theory and are disconnected from the estimates of academic researchers and professional investors. Because of this, BGE's analysis does not reflect the best practices of the investment industry, and its requested ROE is a clear outlier from the expectations of equity market investors and academics.

4. Based on my above recommendations (1) through (3), the Commission should set BGE's overall rate of return at 6.07 percent.
5. The Commission should reject BGE's proposed Operating Income Adjustment 25 because the adjustment unreasonably increases the company's equity ratio and overall ROR for non-EmPOWER assets, raising its revenue requirement by $6.96 million and largely eliminating the impact of Operating Income Adjustment 24, which was made to comply with statutory mandates in House Bill 864.

Q. Please summarize the impact that adopting your recommendations would have on BGE's ratepayers.

A. In this proceeding, BGE has requested a rate increase of $156 million, of which $39 million would be to increase its profits. Adopting a 7.3 percent ROE would lower rates relative to the company's proposal by $134 million annually. Of that, residential customers would save nearly $82 million, or roughly $110 per customer, in rates each year.

Q. Does your recommendation satisfy the *Hope* and *Bluefield* standards?

A. Yes, a 7.3 percent authorized ROE would satisfy the comparable earnings, capital attraction, and financial integrity standards from *Hope* and *Bluefield*. My testimony presents a significant body of evidence that BGE's currently authorized ROE, like that of most electric utilities, exceeds its COE by several percentage points. My testimony has shown that BGE's analysis is flawed in several respects and that those flaws led it to request an ROE that is unnecessarily high.

Reducing BGE's ROE to 7.3 percent, a conservative estimate of its actual COE, would enable investors to earn a fair market return comparable to the market return offered to investors in similar regulated utilities while enabling BGE to attract capital and preserve a strong credit rating.

Q. Does this conclude your direct testimony?

A. Yes, it does.

CURRENT
ENERGY GROUP

Dan Cassara

Senior Consultant, (520) 286-5244, dcassara@currentenergy.group

Education

Master of Public Administration in Environmental Science and Policy
Columbia University School of International and Public Affairs (2025)

Bachelor of Arts, Economics
University of Chicago (2016)

Work Experience

Senior Consultant, Current Energy Group (July 2026 – Present)
Consultant (July 2025 – July 2026)

- Work with public interest organizations, consumer advocates, and utility commissions on regulatory issues involving cost of service, return on equity, and rate design
- Conduct financial analysis on policy, regulation, and tariffs for utility policy and regulatory proceedings

Graduate Student Consultant, Clean Tomorrow, (Jan. 2025 – May 2025)

- Manage a team of graduate student consultants producing a research report and policy briefs outlining how state-level policies such as Community Benefit Agreements impact the accrual of benefits to communities from the development of clean energy
- Lead client engagements, interview key stakeholders such as academic experts, project developers, and community organizers, edit reports and briefs, build and iterate on a work plan for the team, and present key findings to the client

Project Manager Financial Inclusion, Center for Effective Global Action – University of California, Berkeley (Aug. 2021 – May 2024)

- Managed a portfolio of 25 research projects with an active budget of $2.3M
- Co-authored research synthesis report on the impacts of small digital loans and presented the findings at three conferences and five industry network gatherings
- Authored research summaries, thought leadership articles, and policy briefs, driving a 19% increase in newsletter subscribers and 55% increase in website readership

Senior Associate, Dimensional Fund Advisors (DFA) (Jan. 2019 – Aug. 2021)
Associate (Aug. 2016 – Dec. 2018)

- Serviced 50+ client relationships representing ~$8B in assets through investment analysis, marketing support, and continued education on research and investment strategies

- Completed rigorous portfolio analyses to disaggregate performance driversDeepened key national and global partnerships and worked with firm leadership on protocols for expanded relationship rollouts
- Co-authored white paper on the global private bank landscape, providing insights on market trends, distribution frameworks, competitive threats, and recommendations for positioning

Select Publications

"Recent Trends in Colorado's Electric Rates"
Report (Apr. 2026)
Co-authored a report assessing the drivers of recent electric rate increases in Colorado and trends in capital and O&M expenditures among utilities.
Report

"Analyzing Common Cost of Equity Models & Their Application in Public Utility Rate Cases"
Report (Forthcoming)
Co-authored a report analyzing the proper use of common financial models for determining a utility's Return on Equity, common arguments utilities make to justify higher returns, and the impact that inflated returns have on residential consumer bills.

Relevant Experience

Maryland Office of People's Counsel
Re: Application of Washington Gas Light Company for Authority to Increase its Existing Rates and Charges and to Revise its Terms and Conditions for Gas Service. Case No. 9849

- Evaluated Return on Equity (ROE) testimony and identified flaws in the Company's analysis that resulted in it proposing an excessive ROE
- Analyzed a counter-proposal that better aligned the Company's ROE with its cost of capital and demonstrated that this proposal would lead to significant ratepayers savings without harming the utility's ability to attract capital or maintain its credit

Walnut Way Conservation Corp.
Application of Wisconsin Electric Power Company for Approval of its Very Large Customer and Bespoke Resources Tariffs. Docket No. 6630-TE-113

- Evaluated Large Load Tariff and identified updated Tariff design elements that would more effectively protect ratepayers from cost shifting and stranded assets
- Analyzed proposal for a Return on Equity adder and advocated for excess revenues to help offset costs for existing ratepayers

Western Resource Advocates
In the Matter of the Joint Application of Public Service Company of New Mexico, TXNM Energy, Inc. and Troy ParentCo LLC for Approval of Acquisition ad Merger of Troy Merger Sub Inc. with TXNM Energy, Inc.; Approval of a General Diversification Plan; and All Other Authorizations and Approvals Required to Consummate and Implement This Transaction. Case No. 25-00060-UT

- Analyzed the investment model and strategic guidance underpinning the proposed acquisition to understand the drivers of Blackstone Infrastructure's returns and the impact the transaction was expected to have on ratepayer bills

- Demonstrated the financial and environmental risks the proposed transaction posed to customers and developed conditions that would ameliorate the risks

Anonymous Firm
Large Load Pricing Model

- Built a pricing model that estimated the incremental cost a new large load on Xcel Energy's grid would create
- Performed sensitivity analysis to understand the drivers of incremental cost under different grid resource mixes, resource costs, and utilization rates

Green Mountain Power
Embedded Cost-of-Service Model

- Supported the development of an Embedded Cost-of-Service model which serves as the foundation for Green Mountain Power's future rate case and rate design proceedings
- Developed illustrative revenue apportionment methodology to better understand the impact of rate design on customer class-level revenue requirements

Expert Testimony

2. In Re: Application of Duke Energy Progress, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and Performance-Based Regulation (Docket No. E-2, Sub 1380). On Behalf of the Attorney General's Office of North Carolina.
Return on Equity
Direct

1. In Re: Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and Performance-Based Regulation (Docket No. E-7, Sub 1329). On Behalf of the Attorney General's Office of North Carolina.
Return on Equity
Direct

Case No. 9888

Summary of Results

Cost of Equity Model	Cassara Proxy Group	McKenzie Proxy Group	Exelon Corp.
Capital Asset Pricing Model	**6.81%**	**6.91%**	**6.35%**
Multi-Stage DCF			
Growth = GDP	7.82%	7.76%	8.04%
Growth = Utility EPS	7.57%	7.51%	7.79%
Average	**7.70%**	**7.64%**	**7.91%**
Mean Result	7.26%	7.28%	7.13%
ROE Recommendation		**7.30%**	
Constant Growth DCF			
Growth = GDP	7.27%	7.22%	7.64%
Growth = Utility EPS	6.90%	6.86%	7.27%
Average	**7.08%**	**7.04%**	**7.46%**
All Models			
Min	6.81%	6.91%	6.35%
Max	7.70%	7.64%	7.91%
Midpoint	7.26%	7.28%	7.13%

Case No. 9888

Equity Risk Premium Calculations

HISTORIC EQUITY RISK PREMIUM

	Geometric Avg. Historical Return (1928-2025)	
[1]	S&P 500 Index	10.02%
[2]	Long-Term US Treasuries	4.53%
	Historic ERP	**5.48%**

Notes:

[1] - [2] Source: A. Damodaran, Historical Returns on Stocks, Bonds, Real Estate and Gold (for historical risk premiums)

IMPLIED EQUITY RISK PREMIUM

Implied ERP	**4.23%**

Source: A. Damodaran, Implied ERP (annual) from 1960 to Current

RICHMOND CFOs ERP

[1]	S&P 500 Expected Return	9.30%
[2]	Risk-Free Rate	4.68%
	Richmond CFOs ERP	**4.62%**

Notes:

[1] Source: The CFO Survey – Q2 2026, Duke Fuqua School of Business, Federal Reserve Banks of Richmond and Atlanta (May 18 - Jun. 5, 2026)

[2] Source: Federal Reserve Bank of St. Louis, Market Yield on U.S. Treasury Securities at 10-Year Constant Maturity

McKINSEY METHODOLOGY ERP

[1]	COE in Real Dollar Terms	7.00%
[2]	Expected Inflation	2.29%
[3]	S&P 500 Expected Return	9.29%
[4]	Risk-Free Rate	4.68%
	McKinsey ERP	**4.60%**

Notes:

[1] Source: V. Gupta, D. Kohn, T. Koller, and W. Rehm, Markets versus textbooks: Calculating today's cost of equity, McKinsey & Company

[2] Source: Federal Reserve Bank of St. Louis, 10-Year Breakeven Inflation Rate

[3] Equals [1] + [2]

[4] Source: Federal Reserve Bank of St. Louis, Market Yield on U.S. Treasury Securities at 10-Year Constant Maturity

Case No. 9888
Capital Asset Pricing Model (CAPM)

Company	Ticker	Risk-Free Rate [1]	Yahoo! Finance [2]	Zacks [3]	Avg. Beta [4]	Historic ERP [5]	Implied ERP [6]	Richmond CFOs ERP [7]	McKinsey ERP [8]	Avg. ERP [9]	Low Est. COE [10]	High Est. COE [11]	Avg. Est. COE [12]
Ameren Corp.	AEE	4.68	0.47	0.51	0.49	5.48	4.23	5.02	4.60	4.83	6.76	7.37	7.05
Consolidated Edison	ED	4.68	0.26	0.27	0.27	5.48	4.23	5.02	4.60	4.83	5.81	6.14	5.96
Fortis Inc.	FTS	4.68	0.41	0.42	0.42	5.48	4.23	5.02	4.60	4.83	6.44	6.96	6.69
NextEra Energy, Inc.*	NEE	4.68	0.64	0.65	0.65	5.48	4.23	5.02	4.60	4.83	7.41	8.22	7.80
OGE Energy Corp.	OGE	4.68	0.51	0.52	0.52	5.48	4.23	5.02	4.60	4.83	6.86	7.51	7.17
Portland General Elec.	POR	4.68	0.53	0.51	0.52	5.48	4.23	5.02	4.60	4.83	6.88	7.53	7.20
PPL Corp.	PPL	4.68	0.58	0.57	0.58	5.48	4.23	5.02	4.60	4.83	7.12	7.84	7.46
Southern Company	SO	4.68	0.32	0.33	0.33	5.48	4.23	5.02	4.60	4.83	6.06	6.47	6.25
WEC Energy Group	WEC	4.68	0.46	0.47	0.47	5.48	4.23	5.02	4.60	4.83	6.65	7.23	6.93
Xcel Energy Inc.	XEL	4.68	0.40	0.39	0.40	5.48	4.23	5.02	4.60	4.83	6.36	6.85	6.59
Mean: McKenzie Proxy Group			0.46	0.46	0.46						6.63	7.21	6.91
Median: McKenzie Proxy Group			0.47	0.49	0.48						6.70	7.30	6.99
Mean: Cassara Proxy Group			**0.44**	**0.44**	**0.44**						**6.55**	**7.10**	**6.81**
Median: Cassara Proxy Group			0.46	0.47	0.47						6.65	7.23	6.93
Exelon	EXC	4.68	0.39	0.30	0.35	5.48	4.23	5.02	4.60	4.83	6.14	6.57	6.35

Notes:

*The Cassara Proxy Group subtracts NextEra Energy from the McKenzie Proxy Group due to its pending merger with Dominion
[1] Source: Federal Reserve Bank of St. Louis, FRED Database, Market Yield on U.S. Treasury Securities at 10-Year Constant Maturity
[2] Source: Yahoo! Finance
[3] Source: Zacks
[4] Average of [B] and [C]
[5] See Exhibit DMC-3, page 1
[6] See Exhibit DMC-3, page 1
[7] See Exhibit DMC-3, page 1
[8] See Exhibit DMC-3, page 1
[9] Average of [5] through [8]
[10] Min. Est. COE = [1] + [4]*[6]
[11] Max. Est. COE = [1] + [4]*[5]
[12] Avg. Est. COE = [1] + [4]*[9]

Case No. 9888

Constant Growth Discount Cash Flow Model | Growth Rate = U.S. GDP Growth

Company	Ticker	Stock Price [1]	Dividend Yield [2]	Forward Dividend Yield [3]	Growth Rate [4]	Cost of Equity [5]
Ameren Corp.	AEE	108.16	2.75%	2.82%	3.80%	6.62%
Consolidated Edison	ED	107.87	3.23%	3.27%	3.80%	7.07%
Fortis Inc.	FTS	55.83	4.60%	3.36%	3.80%	7.16%
NextEra Energy, Inc.*	NEE	84.98	2.88%	3.02%	3.80%	6.82%
OGE Energy Corp.	OGE	46.62	3.61%	3.59%	3.80%	7.39%
Portland General Elec.	POR	49.65	4.35%	4.51%	3.80%	8.31%
PPL Corp.	PPL	35.11	3.25%	3.30%	3.80%	7.10%
Southern Company	SO	91.35	3.37%	3.44%	3.80%	7.24%
WEC Energy Group	WEC	108.14	3.48%	3.59%	3.80%	7.39%
Xcel Energy Inc.	XEL	77.77	3.05%	3.31%	3.80%	7.11%
Mean: McKenzie Proxy Group			3.46%	3.42%		7.22%
Median: McKenzie Proxy Group			3.31%	3.34%		7.14%
Mean: Cassara Proxy Group			**3.52%**	**3.47%**		**7.27%**
Median: Cassara Proxy Group			3.37%	3.36%		7.16%
Exelon	EXC	44.95	3.75%	3.84%	3.80%	7.64%

Notes:

*The Cassara Proxy Group subtracts NextEra Energy from the McKenzie Proxy Group due to its pending merger with Dominion

[1] Source: Yahoo! Finance

[2] Trailing Twelve Month Dividends / [1]; Source: Yahoo! Finance

[3] Expected Forward Dividends / [1]; Source: Yahoo! Finance

[4] Long-run U.S. GDP Group; Source: U.S. Congressional Budget Office

[5] Equals [3] + [4]

Case No. 9888

Constant Growth Discount Cash Flow Model | Growth Rate = Utility Sector Historical EPS Growth

Company	Ticker	Stock Price [1]	Dividend Yield [2]	Forward Dividend Yield [3]	Growth Rate [4]	Cost of Equity [5]
Ameren Corp.	AEE	108.16	2.75%	2.82%	3.43%	6.25%
Consolidated Edison	ED	107.87	3.23%	3.27%	3.43%	6.70%
Fortis Inc.	FTS	55.83	4.60%	3.36%	3.43%	6.79%
NextEra Energy, Inc.*	NEE	84.98	2.88%	3.02%	3.43%	6.45%
OGE Energy Corp.	OGE	46.62	3.61%	3.59%	3.43%	7.02%
Portland General Elec.	POR	49.65	4.35%	4.51%	3.43%	7.94%
PPL Corp.	PPL	35.11	3.25%	3.30%	3.43%	6.73%
Southern Company	SO	91.35	3.37%	3.44%	3.43%	6.87%
WEC Energy Group	WEC	108.14	3.48%	3.59%	3.43%	7.02%
Xcel Energy Inc.	XEL	77.77	3.05%	3.31%	3.43%	6.74%
Mean: McKenzie Proxy Group			3.46%	3.42%		6.86%
Median: McKenzie Proxy Group			3.31%	3.34%		6.77%
Mean: Cassara Proxy Group			**3.52%**	**3.47%**		**6.90%**
Median: Cassara Proxy Group			3.37%	3.36%		6.79%
Exelon	EXC	44.95	3.75%	3.84%	3.43%	7.27%

Notes:

*The Cassara Proxy Group subtracts NextEra Energy from the McKenzie Proxy Group due to its pending merger with Dominion

[1] Source: Yahoo! Finance

[2] Trailing Twelve Month Dividends / [1]; Source: Yahoo! Finance

[3] Expected Forward Dividends / [1]; Source: Yahoo! Finance

[4] Long-run growth in Utility Sector EPS; Source: S&P 500 Earnings and Estimates Report

[5] Equals [3] + [4]

Case No. 9888

Multi-Stage Discount Cash Flow Model | Growth Rate = U.S. GDP Growth

					Dividends per Share																	
Company	**Ticker**	**Stock Price**	**Forecasted EPS Growth**	**Terminal Growth Rate**	**TTM**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**Cost of Equity**
		[1]	[2]	[3]	[4]	[5]					[6]										[7]	[8]
Ameren Corp.	AEE	108.16	7.63%	3.80%	2.92	3.03	3.26	3.45	3.64	3.85	4.06	4.28	4.50	4.72	4.94	5.17	5.39	5.62	5.84	6.06	193.84	6.9%
Consolidated Edison	ED	107.87	5.68%	3.80%	3.48	3.58	3.78	3.99	4.22	4.46	4.70	4.94	5.19	5.45	5.70	5.96	6.22	6.48	6.74	6.99	192.23	7.4%
Fortis Inc.	FTS	55.83	5.61%	3.80%	1.84	1.89	2.00	2.16	2.35	2.54	2.74	2.95	3.15	3.36	3.56	3.76	3.96	4.14	4.32	4.49	103.37	8.1%
NextEra Energy, Inc.*	NEE	84.98	8.36%	3.80%	2.38	2.48	2.69	2.86	3.05	3.25	3.45	3.65	3.86	4.07	4.28	4.49	4.70	4.90	5.10	5.29	153.75	7.2%
OGE Energy Corp.	OGE	46.62	6.50%	3.80%	1.71	1.77	1.88	2.01	2.16	2.31	2.47	2.63	2.79	2.95	3.11	3.27	3.43	3.58	3.73	3.87	84.73	8.4%
Portland General Elec.	POR	49.65	7.13%	3.80%	2.14	2.22	2.37	2.53	2.70	2.88	3.06	3.24	3.43	3.62	3.81	4.00	4.18	4.36	4.54	4.72	89.25	9.1%
PPL Corp.	PPL	35.11	6.62%	3.80%	1.12	1.16	1.23	1.33	1.44	1.55	1.67	1.79	1.91	2.03	2.14	2.26	2.38	2.49	2.59	2.69	64.64	8.0%
Southern Company	SO	91.35	7.93%	3.80%	2.98	3.10	3.34	3.61	3.90	4.21	4.52	4.85	5.17	5.50	5.82	6.14	6.45	6.75	7.03	7.30	168.40	8.1%
WEC Energy Group	WEC	108.14	7.95%	3.80%	3.68	3.83	4.13	4.48	4.86	5.27	5.69	6.12	6.55	6.98	7.41	7.83	8.24	8.62	8.99	9.33	200.94	8.4%
Xcel Energy Inc.	XEL	77.77	8.45%	3.80%	2.32	2.42	2.62	2.62	2.62	2.62	2.62	2.62	2.62	2.62	2.62	2.62	2.62	2.62	2.62	2.62	125.13	5.9%
Mean: McKenzie Proxy Group			7.19%																			7.76%
Median: McKenzie Proxy Group			7.38%																			8.05%
Mean: Cassara Proxy Group			**7.06%**																			**7.82%**
Median: Cassara Proxy Group			7.13%																			8.13%
Exelon	EXC	44.95	5.98%	3.80%	1.64	1.69	1.79	1.90	2.01	2.13	2.25	2.38	2.51	2.63	2.76	2.89	3.02	3.15	3.28	3.40	80.27	8.04%

Notes:

*The Cassara Proxy Group subtracts NextEra Energy from the McKenzie Proxy Group due to its pending merger with Dominion
[1] Source: Yahoo! Finance
[2] Average of EPS forecasts from zacks and S&P CapIQ
[3] Long-run U.S. GDP Group; Source: U.S. Congressional Budget Office
[4] Trailing Twelve Month Dividends. Source: zacks.com
[5] For 2026 to 2030, Prior Year * (1 + [2])
[6] For 2031 to 2040, Prior * (1 + Transition Growth); Transition Growth decreases from [2] to [3] by ([2] - [3]) / 10 each year
[7] Terminal Value equals Year 2040 DPS divided by ([8] - [3])
[8] Implied value such that [7] = [1]

Case No. 9888

Multi-Stage Discount Cash Flow Model | Growth Rate = Utility Sector Historical EPS Growth Rate

Company	Ticker	Stock Price	Forecasted EPS Growth	Terminal Growth Rate	Dividends per Share TTM	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	Cost of Equity
		[1]	[2]	[3]	[4]	[5]					[6]										[7]	[8]
Ameren Corp.	AEE	108.16	7.63%	3.43%	2.92	3.03	3.26	3.45	3.64	3.85	4.06	4.27	4.49	4.70	4.92	5.13	5.34	5.55	5.75	5.95	184.52	6.7%
Consolidated Edison	ED	107.87	5.68%	3.43%	3.48	3.58	3.78	3.99	4.22	4.46	4.70	4.94	5.18	5.43	5.67	5.92	6.16	6.40	6.63	6.86	183.15	7.2%
Fortis Inc.	FTS	55.83	5.61%	3.43%	1.84	1.89	2.00	2.16	2.35	2.54	2.74	2.94	3.15	3.35	3.55	3.74	3.92	4.09	4.25	4.40	98.64	7.9%
NextEra Energy, Inc.*	NEE	84.98	8.36%	3.43%	2.38	2.48	2.69	2.86	3.05	3.25	3.45	3.65	3.85	4.06	4.26	4.46	4.65	4.84	5.02	5.19	146.45	7.0%
OGE Energy Corp.	OGE	46.62	6.50%	3.43%	1.71	1.77	1.88	2.01	2.16	2.31	2.47	2.63	2.78	2.94	3.10	3.25	3.40	3.54	3.67	3.80	80.87	8.1%
Portland General Elec.	POR	49.65	7.13%	3.43%	2.14	2.22	2.37	2.53	2.70	2.88	3.06	3.24	3.43	3.61	3.79	3.97	4.14	4.31	4.47	4.63	85.27	8.9%
PPL Corp.	PPL	35.11	6.62%	3.43%	1.12	1.16	1.23	1.33	1.44	1.55	1.67	1.78	1.90	2.02	2.13	2.25	2.35	2.45	2.55	2.64	61.66	7.7%
Southern Company	SO	91.35	7.93%	3.43%	2.98	3.10	3.34	3.61	3.90	4.21	4.52	4.84	5.16	5.48	5.79	6.09	6.38	6.66	6.92	7.16	160.69	7.9%
WEC Energy Group	WEC	108.14	7.95%	3.43%	3.68	3.83	4.13	4.48	4.86	5.27	5.69	6.11	6.54	6.96	7.37	7.77	8.16	8.52	8.85	9.16	191.84	8.2%
Xcel Energy Inc.	XEL	77.77	8.45%	3.43%	2.32	2.42	2.62	2.62	2.62	2.62	2.62	2.62	2.62	2.62	2.62	2.62	2.62	2.62	2.62	2.62	119.20	5.6%
Mean: McKenzie Proxy Group			7.19%																			7.51%
Median: McKenzie Proxy Group			7.38%																			7.80%
Mean: Cassara Proxy Group			**7.06%**																			**7.57%**
Median: Cassara Proxy Group			7.13%																			7.89%
Exelon	EXC	44.95	5.98%	3.43%	1.64	1.69	1.79	1.90	2.01	2.13	2.25	2.38	2.50	2.62	2.75	2.87	2.99	3.11	3.22	3.33	76.56	7.79%

Notes: 6.35%

*The Cassara Proxy Group subtracts NextEra Energy from the McKenzie Proxy Group due to its pending merger with Dominion 8.04%

[1] Source: Yahoo! Finance
[2] Average of EPS forecasts from zacks and S&P CapIQ
[3] Long-run U.S. GDP Group; Source: U.S. Congressional Budget Office
[4] Trailing Twelve Month Dividends. Source: zacks.com
[5] For 2026 to 2030, Prior Year * (1 + [2])
[6] For 2031 to 2040, Prior * (1 + Transition Growth); Transition Growth decreases from [2] to [3] by ([2] - [3]) / 10 each year
[7] Terminal Value equals Year 2040 DPS divided by ([8] - [3])
[8] Implied value such that [7] = [1]

Case No. 9888

Compound Growth Rate for Earnings and Dividends per Share

Company	Ticker	Dividends Start Year [1]	DPS First FY [2]	DPS FY2000 [3]	DPS FY2025 [4]	Full Period DPS CAGR [5]	Since 2000 DPS CAGR [6]	EPS Start Year [7]	EPS First FY [8]	EPS FY2000 [9]	EPS FY2025 [10]	Full Period EPS CAGR [11]	Since 2000 EPS CAGR [12]
Ameren Corp.	AEE	1979	1.44	2.54	2.84	1.49%	0.45%	1979	1.73	3.33	5.38	2.50%	1.94%
Consolidated Edison	ED	1979	2.44	2.18	3.40	0.72%	1.79%	1979	4.51	2.75	5.66	0.49%	2.93%
Fortis Inc.	FTS	1995	0.31	0.31	1.78	6.02%	7.24%	1995	0.46	0.45	2.44	5.71%	6.98%
NextEra Energy, Inc.*	NEE	1979	2.32	2.16	2.27	-0.05%	0.19%	1979	4.22	4.14	3.31	-0.53%	-0.89%
OGE Energy Corp.	OGE	1979	1.60	1.33	1.69	0.12%	0.96%	1979	1.36	1.89	2.33	1.18%	0.84%
Portland General Elec.	POR	1979	1.70	0.00	2.05	0.41%	n.a.	1979	1.06	0.00	2.77	2.11%	n.a.
PPL Corp.	PPL	1979	2.01	1.05	1.08	-1.35%	0.11%	1979	3.32	3.38	1.60	-1.57%	-2.95%
Southern Company	SO	1979	1.54	1.34	2.94	1.42%	3.19%	1979	1.51	1.52	3.94	2.11%	3.88%
WEC Energy Group	WEC	1979	2.35	1.37	3.57	0.92%	3.91%	1979	3.75	1.28	4.84	0.56%	5.46%
Xcel Energy Inc.	XEL	1979	2.22	1.47	2.26	0.04%	1.73%	1979	3.51	1.60	3.44	-0.04%	3.11%
Mean: McKenzie Proxy Group		1981	1.79	1.37	2.39	0.97%	2.18%	1981	2.54	2.03	3.57	1.25%	2.37%
Median: McKenzie Proxy Group		1979	1.86	1.36	2.26	0.57%	1.73%	1979	2.53	1.75	3.38	0.87%	2.93%
Mean: Cassara Proxy Group		**1981**	**1.73**	**1.29**	**2.40**	**1.09%**	**2.42%**	**1981**	**2.36**	**1.80**	**3.60**	**1.45%**	**2.77%**
Median: Cassara Proxy Group		1979	1.70	1.34	2.26	0.72%	1.76%	1979	1.73	1.60	3.44	1.18%	3.02%
Exelon	EXC	1979	1.80	0.91	1.60	-0.26%	2.29%	1979	1.86	2.81	2.74	0.85%	-0.10%

Notes:

*The Cassara Proxy Group subtracts NextEra Energy from the McKenzie Proxy Group due to its pending merger with Dominion

[1] - [4] Source: S&P

[5] Equals ([4] / [2])^(1/2025-[1]) - 1

[6] Equals ([4] / [3])^(1/25) - 1

[7] - [10] Source: S&P

[11] Equals ([10] / [8])^(1/2025-[7]) - 1

[12] Equals ([10] / [9])^(1/25) - 1

Case No. 9888
Baltimore Gas and Electric Co.
Response to OPC Data Request 3
Request Received: August 10, 2026
Response Date: August 24, 2026
Sponsor(s): Adrien M. McKenzie

Item No.: OPCDR03-01

Please refer to McKenzie Direct at 3:22-24. Mr. McKenzie notes that ROE is related to a utility's "ability to attract capital under reasonable terms."

a. Please characterize reasonable and unreasonable terms as used in this section of Mr. McKenzie's testimony.
b. Are there quantitative measures that are used in determining whether capital has been attracted on reasonable terms? If so, please define such measures and the benchmarks used in determining reasonableness.

RESPONSE:

a. The statements at 3:22-24 of Mr. McKenzie's direct testimony relate to the standards established by the United States Supreme Court, which are discussed in greater detail on pages 4 and 5 of his direct testimony. As noted there, the Court determined in *Bluefield* that the ROE "should be reasonable, sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise money necessary for the proper discharge of its public duties." The Court expanded on these findings in *Hope*, noting that in addition to providing shareholders with a fair return on their capital investment, the ROE "should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain credit and attract capital." While Mr. McKenzie is not a lawyer and does not offer a legal opinion, these decisions establish that the end-result of the ratemaking process must preserve the financial health of the utility. But as the Court has noted in *Permian Basin*, "neither law nor economics has yet devised generally accepted standards for the review of rate-making orders." While the Court has not established specific guidelines as to terms that would be considered reasonable or unreasonable, the ability of the utility to maintain it's financial standing (*e.g*, credit ratings) and access to sufficient operating funds and additional debt and equity capital would be considerations in such a determination.

b. Please see the response to subpart (a), above.

Case No. 9888
Baltimore Gas and Electric Co.
Response to OPC Data Request 3
Request Received: August 10, 2026
Response Date: August 24, 2026
Sponsor(s): Adrien M. McKenzie

Item No.: OPCDR03-03

Please refer to McKenzie Direct at 19:14-20. Mr. McKenzie describes yields on 30-year Treasuries as a guide to the risk-free rate and states that they "provide an observable benchmark for underlying trends in capital costs."

a. Does Mr. McKenzie believe the relationship between Treasury bond yields and the cost of capital holds if Treasury bond yields decrease? In other words, would a decrease in 30-year Treasury bond yields generally correspond to a decrease in the cost of capital?
b. If the answer to subpart (a) is "no," please explain why not.

RESPONSE:

a. A utility's cost of capital is a weighted average of cost of its components; typically, long-term debt and common equity. In general, investors' required rates of return on financial assets, whether debt or common equity, are a function of underlying conditions in the economy and capital markets, as well as the relative risks associated with each alternative. As a result, the returns required by investors on Treasury bonds, debt securities and common stock would be expected to move in the same direction, although not in lockstep. However, there are exceptions to this general relationship. For example, during times of significant risk-off behavior on the part of investors, Treasury bond yields may decline at the same time as the returns demanded on corporate bonds and common stocks rise significantly. In addition, actions of the Federal Reserve (e.g., quantitative easing) may have an outsized impact on the yields on Treasury securities that are not replicated in other sectors of the capital market.

b. Please refer to the response to subpart (a), above.

Case No. 9888
Baltimore Gas and Electric Co.
Response to OPC Data Request 3
Request Received: August 10, 2026
Response Date: August 24, 2026
Sponsor(s): Adrien M. McKenzie

Item No.: OPCDR03-05

Please refer to McKenzie Direct at 40, footnote 72. Mr. McKenzie discusses the assumptions underlying the constant growth DCF model and states they all "extend to infinity," but that in practice they "are never met."

a. Has Mr. McKenzie conducted any analysis quantifying how much deviation from the assumptions of the Constant Growth DCF is acceptable before the model no longer provides a reasonable estimate of the cost of equity?
    1. If yes, please provide said analysis in unlocked Excel format with all formulas intact, and provide a copy of all research that Mr. McKenzie relied on.
b. Is Mr. McKenzie aware of any research from academia or investment analysts quantifying how much deviation from the assumptions of the Constant Growth DCF is acceptable before the model no longer provides a reasonable estimate of the cost of equity?
    1. If yes, please provide a copy of all such research.
    2. If yes, how did Mr. McKenzie incorporate such research into his analysis?
c. If the answer to subparts (a) and (b) is "no," how did Mr. McKenzie determine that a Constant Growth DCF model would provide a reasonable estimate for BGE's cost of equity despite the admission that the model's underlying assumptions do not hold in practice?
d. Is a five-year forecast sufficiently long-term to match the assumption that earnings and dividends will always grow at the same rate?
e. If the answer to subpart (d) is no, please justify the use of five-year forecasts with the Constant Growth DCF model.
f. If the answer to subpart (d) is yes, please define the shortest amount of time that would be sufficiently long-term in nature to use in a Constant Growth DCF.
g. Please see Exhibit AMM-5. Is it plausible that electric utility companies could maintain an EPS growth rates of up to 9 percent into "infinity"? If yes, please explain why this would be reasonable.

RESPONSE:

a. No.

b. No.

c. As discussed at pages 38-40 of Mr. McKenzie's Direct Testimony, all financial models used to estimate the cost of equity—including the DCF approach—are necessarily based on simplifying assumptions, and there is no single financial model that can be considered failsafe. While the restrictive assumptions underlying the DCF model are never met in practice, it nevertheless is widely recognized as a theoretically sound approach to estimating investors' cost of equity.

d. As explained at page 41 of Mr. McKenzie's Direct Testimony, in constant growth DCF theory, earnings, dividends, book value, and market price are all assumed to grow in lockstep, and the growth horizon of the DCF model is infinite. But implementation of the DCF model is not a theoretical exercise; it is an attempt to replicate the mechanism investors used to arrive at observable stock prices. A variety of techniques can be used to derive growth rates, but the only "*g*" that matters in applying the DCF model is the value that investors expect. As Mr. McKenzie noted on page 42 of his Direct Testimony, investors are unlikely to expect earnings and dividends to grow at the same rate for utilities, since dividend policies must also consider the need for internally generated funds to finance additional investment.

e. Please refer to the response to subpart (d), above.

f. Mr. McKenzie has not conducted any independent research to "define the shortest amount of time that would be sufficiently long-term in nature to use in a Constant Growth DCF." As noted in response to subpart (d), the key consideration in evaluating a growth rate to apply the constant growth DCF model is the expectations of investors. Peer-reviewed research authored by Dr. Myron Gordon, a recognized scholar on the application of the DCF model, reported that "Analysts do not predict earnings beyond five years, which suggests that any consensus of opinion among investors probably deteriorates quickly after five years." Refer to *OPCDR03-05-Attachment 1* for the referenced publication.

g. Please refer to the response to subpart (d), above. The concept of "infinity" is irrelevant in the application of the DCF model.

Case No. 9888
Baltimore Gas and Electric Co.
Response to OPC Data Request 3
Request Received: August 10, 2026
Response Date: August 24, 2026
Sponsor(s): Adrien M. McKenzie

Item No.: OPCDR03-08

Please refer to McKenzie Direct at 53:7-9. Mr. McKenize states that flaws with the CAPM are "widely reported in the finance literature" and provide justification for the ECAPM model.

a. Is Mr. McKenzie claiming that there is "widely reported" support for the ECAPM model?
b. Please provide a PDF copy of all research studies Mr. McKenzie is aware of that provide support for the validity of the ECAPM model.
c. Please provide a PDF copy of all investment analyst reports Mr. McKenzie is aware of that utilize the ECAPM for investment valuation.

RESPONSE:

a. As noted at page 53-54 of Mr. McKenzie's Direct Testimony, his application of the ECAPM was based on findings reported in the recognized treatise, *New Regulatory Finance*. Citations to published financial research studies supporting the ECAPM model presented in *New Regulatory Finance* are provided in Table 6-2 and listed in the references, both of which are attached (*OPCDR03-08-Attachment 1* and *OPCDR03-08-Attachment 2*). The empirically observed flattening of the Security Market Line is well recognized. For example, *Morningstar* reported that:

> Empirically, many studies have shown that the relationship between beta and long-term average return (a proxy for expected return) is flatter than what is predicted by the standard CAPM. In other words, securities with low betas have higher average returns than predicted by the standard CAPM, and securities with high betas have lower average returns than predicted. Paul Kaplan, Why the CAPM Falls Flat, Morningstar (Sep. 19, 2019), https://www.morningstar.com/portfolios/why-capm-falls-flat (last visited Dec. 23, 2025).

Similarly, the recognized financial textbook by Bodie, Kane, and Marcus noted that tests of the CAPM performed by John Lintner and replicated by Merton Miller and Myron Scholes demonstrated that the Securities Market Line predicted by the CAPM is "too flat," and that "the measured slope of the SML is less than it should be by a statistically significant margin." Bodie, Kane, and Marcus, *Investments* (10^{th} Ed.), McGraw-Hill/Irwin (2014) at 417 (refer to attached reference *OPCDR03-08-Attachment 3*). With respect to the application of the CAPM to utility stocks specifically, an article published in the Journal of Finance concluded that, "The assertion that risk premiums are proportional to NYSE betas is shown to result in a downward (upward) biased prediction of the cost of equity capital for a public utility having a NYSE beta that is less (greater) than unity . . ." Litzenberger, Ramaswamy, and Sosin, *On the CAPM Approach to the Estimation of A Public Utility's Cost of Equity Capital,* Journal of Finance, Vol. XXXV, No. 2 (May 1980). https://onlinelibrary.wiley.com/doi/10.1111/j.1540-6261.1980.tb02166.x (last visited Dec. 23, 2025).

This underlying bias in the theoretical CAPM has been recognized by other regulators. For example, the Staff of the Maryland Public Service Commission has also noted that "the ECAPM model adjusts for the tendency of the CAPM model to underestimate returns for low Beta stocks," and concluded that, "the ECAPM gives a more realistic measure of the ROE than the CAPM model does." Maryland Public Service Commission, Case No. 9299 *Direct Testimony and Exhibits of Julie McKenna* (Oct. 12, 2012) at 9. The New York Department of Public Service also routinely incorporates the results of the ECAPM approach, which it refers to as the "zero-beta CAPM." *See, e.g.* New York Department of Public Service, Cases 19-E-0065 19-G-0066, *Prepared Fully Redacted Testimony of Staff Finance Panel* (May 2019) at 94-95.

b. Please refer to the response to subpart (a), above. Mr. McKenzie has not conducted an exhaustive research study to identify each and every research study that provide support for the validity of the ECAPM model.

c. Mr. McKenzie is not aware of an investment analyst report that specifically utilizes the ECAPM as the basis to value a common stock.

Case No. 9888
Baltimore Gas and Electric Co.
Response to OPC Data Request 3
Request Received: August 10, 2026
Response Date: August 24, 2026
Sponsor(s): Adrien M. McKenzie

Item No.: OPCDR03-09

Please refer to McKenzie Direct at 55:7-8. In discussing the Utility Risk Premium model, Mr. McKenzie states that "[t]his method is routinely referenced by the investment community and in academia."

a. Please confirm whether "this method," as used in this section of Mr. McKenzie's testimony, refers to Risk Premium models broadly, including the CAPM model, or if it refers specifically to the Utility Risk Premium model as presented by Mr. McKenzie.
b. If the answer to subpart (a) is that the reference is the Utility Risk Premium model as presented by Mr. McKenzie, please provide a PDF copy of all research and investment analyst reports that support Mr. McKenize's conclusion that the Utility Risk Premium model is widely used.
c. If the answer to subpart (a) is that the reference is made to Risk Premium models broadly, including the CAPM, does Mr. McKenzie believe that the Utility Risk Premium model as he has presented it is widely used by the investment community? If so, please provide a PDF copy of all research and investment analyst reports that support this conclusion.

RESPONSE:

a. While distinct from the CAPM, Mr. McKenzie's reference to "this model" refers to the risk premium approach more broadly, and not specifically to the methodology presented in Company Exhibit AMM-9.

b. Please refer to the response to subpart (a).

c. Please refer to the response to subpart (a). As noted there, Mr. McKenzie's testimony denotes risk premium methods as distinct from the CAPM. While the general reference to risk premium models referenced at 55:7-8 of Mr. McKenzie's Direct Testimony is not restricted solely to the application of this approach presented in Company Exhibit AMM-9, reference to allowed ROEs is a recognized basis on which to apply this approach. For example, *New Regulatory Finance* notes that, "Another risk premium technique to estimate the cost of common equity consists of examining the risk premiums implied in the returns on common equity allowed by regulatory commissions for utilities over some past period relative to the contemporaneous level of the long-term Treasury bond yield." Roger A. Morin, *New Regulatory Finance,* Pub. Utils. Reports, Inc. (2006) at 123. A copy of the referenced document is attached in *OPCDR03-09-Attachment 1*.

Case No. 9888
Baltimore Gas and Electric Co.
Response to OPC Data Request 3
Request Received: August 10, 2026
Response Date: August 24, 2026
Sponsor(s): Michael J. Cloyd

Item No.: OPCDR03-14

Please refer to Cloyd Direct at 16:1-3 - "A deterioration in these [key credit] metrics increases the risk of a credit rating downgrade, which would directly increase BGE's cost of borrowing and, by extension, the cost of service borne by customers" and at 16:18-22, "In short, any near-term rate reduction achieved through an inadequate return or an unsound capital structure would be illusory, as it would be offset - and likely exceeded- by higher long-term financing costs, diminished investment in system safety and reliability, and degradation of the quality of service that BGE's customers expect and deserve."

a. Does Mr. Cloyd intend for "higher long-term financing costs," as used in this section of his testimony, to refer to the cost of debt, the cost of equity, overall rate of return, or some other measure of financing costs?
b. Please provide, in unlocked excel format with formulas intact, all analysis Mr. Cloyd, or anyone at BGE, has conducted on how lowering ROE would impact the "cost of service borne by customers."
c. Has Mr. Cloyd, or anyone at BGE, conducted any analysis on BGE's overall revenue requirement if its ROE was reduced, and its credit rating were downgraded?
d. If the answer to subpart (c) is yes, please provide the analysis in unlocked excel format with all formulas intact.
e. If the answer to subpart (c) is no, please provide the justification for the assertion that near-term rate reductions achieved through a lower ROE would be "illusory" and result in "higher long-term financing costs."

RESPONSE:

a. In this section, Mr. Cloyd is referring to the cost of debt.

b. Not applicable.

c. No, the Company has not performed an analysis on how lowering ROE would impact on the cost of service borne by customers.

d. Not applicable.

e. As explained in response to subpart (c), above, the Company has not conducted a specific quantitative analysis modeling BGE's overall revenue requirement under a scenario where the authorized ROE is reduced and the Company's credit rating is subsequently downgraded. The statement in Mr. Cloyd's testimony is not based on a company-specific revenue requirement sensitivity analysis, but rather on generally accepted utility finance principles and the relationship between regulatory outcomes, financial strength, credit quality, and access to capital.

Mr. Cloyd's testimony reflects the view that investor confidence, credit ratings, and borrowing costs are interconnected. An authorized ROE and capital structure that are insufficient to support a utility's financial profile may place downward pressure on key credit metrics used by rating agencies. A deterioration in those metrics can increase the risk of a future credit rating downgrade, which in turn can increase the cost of debt associated with future financings. Because financing costs are ultimately reflected in customer rates over time, any near-term reduction in rates resulting from a lower ROE could be offset, and potentially exceeded, by higher future borrowing costs.

Case No. 9888
Baltimore Gas and Electric Co.
Response to OPC Data Request 11
Request Received: August 26, 2026
Response Date: September 10, 2026
Sponsor(s): Adrien M. McKenzie

Item No.: OPCDR11-01

Please refer to McKenzie Direct at page 59. Mr. McKenzie states that the Expected Earnings approach "measures the return that investors expect the utility to earn on book value."

a. Has Mr. McKenzie analyzed whether there is a relationship between authorized ROEs, the return the utility earns on book value, and investors' rate of return on common equity in utility stocks?
    i. If yes, please provide all such analysis in unlocked Excel format with formulas intact.
    ii. If no, why not?
b. If the market value of a utility's common stock is consistently above the utility's book value, what does this indicate about the relationship between the utility's return on equity and its cost of equity? Please explain.

RESPONSE:

a. No. Investors' rate of return on common equity is not observable, so it is impossible to analyze the relationship between this variable, authorized ROEs, and the actual return that a utility earns on the book value of its common equity.

b. The implications of market-to-book ratios for the relationship between the utility's return on equity and its cost of equity are unclear, as the well-known financial researcher, Stewart C. Myers, observed:

> [A] straightforward application of the cost of capital to a book value rate base does not automatically imply that the market and book values will be equal. This is an obvious but important point. If straightforward approaches did imply equality of market and book values, then there would be no need to estimate the cost of capital. Stewart C. Myers, *The Application of Finance Theory to Public Utility Rate Cases*, Bell J. Econ. & Mgmt. Science (Spring 1972) at 58-59.

A copy of the referenced document is provided in *OPCDR11-01-Attachment 1*.

Case No. 9888
Baltimore Gas and Electric Co.
Response to OPC Data Request 11
Request Received: August 26, 2026
Response Date: September 10, 2026
Sponsor(s): Adrien M. McKenzie

Item No.: OPCDR11-02

Please refer to Exhibit AMM-10, which shows results for Mr. McKenzie's Expected Earnings analysis.

a. The following questions relate to the Value Line Investment Survey:
   i. Over what time frame are survey participants asked to provide information about expected returns on common equity?
   ii. How many participants respond to the survey on average?
   iii. How many participants responded to the surveys on February 6, March 6, and April 17, 2026 that Mr. McKenzie used in his analysis?
   iv. What is the profile of a typical survey respondent (e.g., Value Line users or a general audience)?

b. Has Mr. McKenzie analyzed whether there is any relationship between the Expected Return on Common Equity reported in the Value Line Investment Survey (column A of the Exhibit) and future realized returns on common equity?
   i. If yes, please provide all such analysis in unlocked Excel format with formulas intact.
   ii. If not, why not?

c. The basis of the analysis, as labeled in Exhibit AMM-10, is Expected Return on Common Equity for each proxy group company. On page 58:2-4, Mr. McKenzie states that "[the expected earnings approach] avoids the complexities and limitations of capital market methods and instead focuses on the returns earned on book equity, which are readily available to investors."
   i. Are the returns on earned on book equity synonymous with the expected return on common equity?
      1. If yes, please explain why.
      2. If not, please explain how the expected earnings analysis that Mr. McKenzie performed focuses on the returns earned on book equity.

RESPONSE:

a.
   i. The projections published by The Value Line Investment Survey are not based on investor surveys.
   ii. Please refer to the response to subpart (a.i.).
   iii. Please refer to the response to subpart (a.i.).
   iv. Please refer to the response to subpart (a.i.).

b.

i. No.

ii. Comparisons of projected returns with actual realized returns are irrelevant in evaluating investors' expectations, which are forward-looking.

c.

i. As discussed at 59:5-11 of Mr. McKenzie's Direct Testimony, expected earned returns on book equity provide a meaningful guide to investors' expected return on common equity for utilities because the allowed ROE is applied to the book value of a utility's rate base.

1. Please refer to the response to subpart (c.i.).
2. Please refer to the response to subpart (c.i.).

Case No. 9888
Baltimore Gas and Electric Co.
Response to OPC Data Request 11
Request Received: August 26, 2026
Response Date: September 10, 2026
Sponsor(s): Adrien M. McKenzie

Item No.: OPCDR11-03

Please refer to McKenzie Direct at 27:13-28:6, where Mr. McKenzie describes his criteria for forming a proxy group.

a. Please confirm that, were he to re-run his analysis today, Mr. McKenzie would remove NextEra Energy from his proxy group due to the announced merger between NextEra Energy and Dominion Energy.
    i. If Mr. McKenzie would not, please explain why not.
b. Please provide all documentation and analysis Mr. McKenzie has reviewed on Value Line's methodology for assigning a Safety Rank and a Financial Strength Rating.

RESPONSE:

a. Confirm.
    i. Please refer to the response to subpart (a).

b. The methodologies used by Value Line to determine the Safety Rank and Financial Strength Rating are proprietary. A general description of these risk measures is provided in *How to Read a Value Line Report*, which is attached in *OPCDR11-03-Attachment 1*.

Case No. 9888
Baltimore Gas and Electric Co.
Response to OPC Data Request 11
Request Received: August 26, 2026
Response Date: September 10, 2026
Sponsor(s): Michael J. Cloyd

Item No.: OPCDR11-07

Please refer to BGE's response to OPC DR 03-14. The Company's response states, "[b]ecause financing costs are ultimately reflected in customer rates over time, any near-term reduction in rates resulting from a lower ROE could be offset, and potentially exceeded, by higher future borrowing costs."

a. Has the Company performed any analysis to support this statement? If so, please share said analysis in unlocked excel format with all formulas intact.
b. Please share all examples the Company is aware of in which lowering a utility's ROE raised future borrowing costs by an amount such that the overall ROR was higher than it had been prior to the utility's ROE being reduced.

RESPONSE:

a. No, the Company has not performed such analysis.

b. The Company is not aware of such examples. Please refer to the response to OPCDR03-14(e) for impacts of lowering the Company's ROE would have on investor confidence, credit ratings, and borrowing costs.

The application of finance theory to public utility rate cases

Stewart C. Myers

Associate Professor of Finance
Sloan School of Management
Massachusetts Institute of Technology

The purpose of this paper is to formulate the implications of finance theory for rate of return regulation. A variety of problems in finance and the law and economics of regulation are reviewed. Also, a regulatory procedure based on finance theory is proposed for practical use.

Finance theory suggests that the "comparable earnings" standard for rate of return regulation ought to be based on utilities' costs of capital. The cost of capital is difficult to measure, since it is defined in terms of investors' expectations. But plausible estimates can be obtained for utilities. The following principle is proposed for use of these estimates: Regulation should assure that the average expected rate of return on desired new utility investment is equal to the cost of capital. This is a definition of "fair return" based on the theory of competitive equilibrium. The principle is consistent with the comparable earnings standard. Only the most obvious, "straightforward" approach to implementing this principle is examined in detail; but this approach is practical and logically sound. It is particularly attractive when combined with conscious use of regulatory lag as an instrument of regulation. There are some difficulties, however, when such a lag is combined with the usual regulatory practice of basing the allowed rate of return on embedded rather than current debt costs.

The problem of determining the appropriate rate base is also discussed. Regulation based on the book value rate base will not generally lead to efficient price, output, or investment decisions. A "competitive market value" rate base would be better from the standpoint of efficiency, since it would lead to long-run marginal cost pricing. However, long-run marginal cost pricing is not generally consistent with the principle that utilities ought to be able to expect to earn their cost of capital on new investment.

1. Introduction

■ There is little argument in practical circles about the broad purpose of regulating public utilities' rates of return. The accepted legal

---

Stewart C. Myers received the A.B. degree from Williams College (1962) and the M.B.A. and Ph.D. degrees from Stanford (1964 and 1967, respectively). He is associate editor of the *Journal of Finance* and the *Journal of Financial and Quantitative Analysis* and has authored or coauthored several articles and a book in the field of finance.

An earlier draft of this paper was presented at the conference on "Problems of Regulation and Public Utilities" held at Dartmouth College in September, 1970. The author is grateful to seminar participants for helpful criticism. Particular thanks are also due to Willard Carleton, David Schwartz, Haskell Wald, and the editors of this Journal for their detailed comments. They are not responsible for any mistakes or misguided opinions. Parts of this paper were also included in "AT&T Cost of Capital Study," presented as testimony by Myers as a staff witness in the 1971 interstate telephone rate case [53].

principle is that "the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks," and sufficient to "attract capital" and maintain credit worthiness.[1]

Finance (the study of investments, capital markets, and financial management) seems directly relevant to the regulatory agencies' attempt to determine the rate of return allowed by law. Although relevant, the applications of finance theory in the regulatory field are not easily seen or understood.

The difficulties involved in transferring finance theory to regulatory problems are attested to by the sharp controversies generated by economists who have ventured into rate proceedings. Disagreements have arisen not only between economists and the usual participants in these proceedings but also among the economists themselves. Thus the problem is not simply *explaining* the theory to the regulators; it has not been clear how the theory should be applied.

The purpose of this paper is to formulate the implications of finance theory for public utility regulation. It is an attempt to apply theory to practical affairs. Thus, detailed attention is given not only to the theory per se but to current regulatory procedures, to alternative procedures, and to the controversies associated with recent attempts to apply finance theory in the regulatory arena.

A few caveats are necessary at the start:

(1) The paper's title means just what it says. This is not a general treatment of finance theory or of public utility rate regulation, but of the application of the former in the latter field. The various aspects of finance and regulation are pursued only as far as is necessary for this limited purpose. For example, I treat the practical problems of estimating utilities' costs of capital only superficially, concentrating instead on how an estimated cost of capital should be used. The problem of estimation is at least as hard and important as that of application, but it is substantially the same problem faced by nonregulated firms. Reviewing it in detail would mean reviewing much of finance theory in detail—a task I cannot attempt here.
(2) I will concentrate on one possible method of regulation, namely control of the overall rate of return earned. For the most part, I am taking the existing legal and procedural framework as given. I do not mean to imply that this framework is necessarily the best one.
(3) The paper does not necessarily describe how regulators actually behave, but how they should behave if the legal and procedural framework is taken at face value and the implications of finance and economic theory are recognized. One suspects that various nonfinancial considerations also affect regulatory behavior, and that regulators respond to objectives that are not evident in the legal and procedural framework.[2]

In short, I do not propose to present an optimal regulatory strategy or a complete positive theory of regulatory behavior. The

[1] This is from the Supreme Court Decision on Federal Power Commission et al. v. Hope Natural Gas Company, 320 U. S. 591 (1949) at 603.

[2] For example, see Posner [38] and Stigler [48] for substantially different views of the role of regulation.

objective is to provide an analysis which can be used to improve existing procedures. This is a limited, but important, objective. Existing procedures not only involve Big Money, but they apparently influence the allocation of resources to, and within, a substantial segment of the economy.

The paper begins with a brief review of the mechanics of rate of return regulation and describes the traditional interpretation of the accepted legal standards for a "fair" rate of return. I argue that the traditional interpretation has serious deficiencies, both in logic and in application. A market-based cost of capital is suggested as an alternative basis for establishing a "fair" return.

The middle portion of the paper (Sections 3 through 5) discusses the definition and measurement of the cost of capital, under the simplifying assumption that the firm is all-equity financed. A number of controversies involving definition and measurement for a regulated firm are discussed.

Measuring the cost of capital is one question, using it another. Sections 6 and 7 summarize the aims of regulation and show that these aims cannot be achieved solely by regulating overall rate of return. However, a somewhat limited objective is logical and feasible; that is, regulation should insure that the expected rate of return on desired new investment is equal to the cost of capital. I present an approach to regulation which is consistent with this principle and discuss the real and alleged problems in implementing it.

The penultimate section drops the assumption of all-equity financing, briefly discusses the problem of determining optimal capital structure, and shows how the approach developed in Sections 6 and 7 can be applied to utilities with complicated capital structures.

The last section includes a brief summary of major conclusions.

2. Review of rate regulation

■ **Regulatory procedures.** A utility's prices are set so that the utility covers its costs, including taxes and depreciation, plus a certain return on investment. The return on investment is obtained by multiplying the "rate base" by an allowed rate of return. The rate base is essentially the book value of the utility's capital investment.[3]

For example, suppose Utility X has a rate base of $100 million. It is producing one billion widgets per year. The allowed rate of return is set at 10 percent overall. Costs are $50 million per year, including depreciation and all taxes.[4] Then the average price of widgets is set as follows:[5]

$$\text{Price per widget} = \frac{\text{Revenue requirements}}{\text{No. of widgets}}$$
$$= \frac{50{,}000{,}000 + 0.10(100{,}000{,}000)}{10^9} = \$0.06\,.$$

Thus widgets are sold for $0.06 until the next regulatory proceeding. This procedure allows the actual return earned to be more or less than

[3] Sometimes "fair value" rate bases are used. They are discussed later in this paper.

[4] That is, costs would be adjusted to cover income taxes associated with a 10-percent return, as well as property taxes, social security contributions, etc.

[5] This paper is concerned with the *level*, not the structure, of utility rates.

TABLE 1

PACIFIC GAS TRANSMISSION CO.–ALLOWED OVERALL RATE OF RETURN

CAPITAL SOURCE	PERCENT OF CAPITALIZATION	RATE OF RETURN IN PERCENT	WEIGHTED RATE
DEBT	79.66	6.13	4.88
EQUITY	20.34	11.64	2.37
TOTAL	100.00		7.25

SOURCE: FPC OPINION NO. 569 [58], P. 15.

10 percent, depending on realized cost and revenues during the period of "regulatory lag" between proceedings.

The allowable rate of return is computed in the same fashion as a weighted average cost of capital, but with important differences. Table 1 shows the computation of the overall rate of return allowed Pacific Gas Transmission Company in a 1970 Federal Power Commission decision. The procedure for computing the overall return, 7.25 percent, is clear from the table, but the table does not show where such numbers typically come from.

(1) The figures listed under "percent of capitalization" refer to the respective percentages of debt and equity listed on the company's books at the time of the rate proceeding. They are book, not market, values. Neither do they necessarily refer to the proportions of debt and equity to be employed in future financing.

(2) The 6.13-percent figure is the "embedded" debt cost—that is, total interest payments divided by the book value of outstanding debt. The company's current borrowing rate can be much higher or lower than the "embedded" debt cost shown.

(3) The percentage cost of equity is a figure arrived at by judgment. I discuss the possible bases for this judgment below.

Although there are opportunities for disagreement at each of these three steps, most argument is centered on the return to equity, so I will start there.

☐ **The legal standard for setting the return to equity.** The governing principle is the Supreme Court's statement in the Hope decision:

> The return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[6]

The first sentence establishes a standard of "comparable earnings," the second, a standard of "capital attraction." The broad language of the Hope decision allows a variety of specific interpretations of these standards.

It is best to start with the comparable earnings standard. In practice, it has been applied in two ways. The traditional and most widely accepted approach[7] defines "returns" as the book rates of

[6] Note 1 *supra*.

[7] The most complete exposition and defense of this method is Leventhal [22].

return of other firms.[8] Those who advocate the traditional approach read the Hope decision in a particular way, namely:

> The return to the equity owner should be commensurate with [*recent book*] returns on [*past*] investments [*made by*] other enterprises having corresponding risks.

This approach rests on a special notion of opportunity cost—in this context, that a utility should be allowed to earn what it *would have* earned had its capital been invested in other firms of comparable risk.[9]

The alternative suggested by finance theory is to define "commensurate return" as the rate of return investors anticipate when they purchase equity shares of comparable risk. This is a *market* rate of return, defined in terms of anticipated dividends and capital gains relative to stock prices.

☐ **Drawbacks of the traditional interpretation.** The traditional interpretation has clear deficiencies. First, the method does not rest easily on the concept of opportunity cost. Opportunity cost is a marginal and forward-looking concept. Thus, the opportunity cost of investing in a particular asset is usually defined as the anticipated rate of return on an incremental investment in the best alternative. However, observed book rates of return are average returns on past investments.

Granted, average and marginal returns are equal at long-run equilibrium in perfectly competitive markets; but this is in an *ex ante* sense. No one argues that perfect competition requires equality of rates of return after the fact in an uncertain world. In any case, usually no attempt is made in regulatory proceedings to see whether the data examined really are marginal rates of return and whether they stem from perfectly competitive situations.

Second, the traditional interpretation of comparable earnings ignores capital markets. This is serious because the Supreme Court specifies that the variable of interest is "the return to the equity owner." The shareholder is not directly interested in the ratio of book earnings to the book value of a company he invests in. He looks at anticipated dividends and capital gains relative to the stock price he has to pay. Thus, it is more relevant to interpret the opportunity cost of capital as the return on securities with risks similar to the stock of the utility in question.

A third objection is that it is difficult, in practice, to find a suitable class of firms with corresponding risks. Suppose you are looking for a company with risk commensurate with Utility X. The likeliest

---

[8] I will use the term "book" to refer to data based on income statements and balance sheets. Thus, the book rate of return to equity is simply the ratio of reported income to net worth as shown on the firm's balance sheet.

[9] The reader may wish to judge for himself whether this characterization of the "traditional interpretation" is accurate. I would suggest starting with two intelligently done examples of this approach. See testimony of Solomon [60] and Friend [37]. Friend concludes: "If regulation is attempting to duplicate competitive results, the rate of return permitted on AT&T equity should be of the same general order of magnitude as on industrials and electric utilities with the same [risk] characteristics. This would require a return in the neighborhood of 12% to be consistent with [book] returns achieved in the last decade by electric companies and even somewhat higher to be consistent with the return achieved by comparable industrials" (p. 17).

candidates are other utilities, whose reported book rates of return reflect past regulatory decisions as well as competitive forces. Basing current regulatory decisions partly on past decisions leads to a dangerously arbitrary standard. One is forced to look elsewhere, to unregulated firms. But such firms presumably are riskier than utilities. Moreover, there is no clear theory about how risk should be related to differences in book rates of return (or even how risk should be defined if the book rate of return is the variable of interest.) In contrast, the relationship of risk and return in capital markets is better understood. This is discussed later in the paper.

The final objection is that accounting rates of return are subject to serious measurement errors and biases, particularly when comparisons are made between firms in different industries. This is also discussed later in the paper.

To summarize, the difficulties with the traditional interpretation of the comparable earnings standard are at very least sufficient to justify examination of alternatives.

3. Finance theory and the cost of capital concept

■ If a utility's allowed rate of return is to be "sufficient . . . to attract capital" and "commensurate with returns on investments in other enterprises having corresponding risks," then it has something in common with the cost of capital as that concept is used in finance. But "the cost of capital" is one of those phrases that can mean a dozen things. Thus, it will be helpful to review the concept briefly.

□ **Definitions and assumptions.** To simplify matters, we will concentrate for the moment on a firm that is all-equity financed and can ignore market imperfections such as transaction costs and taxes. The logic in developing a cost of capital (i.e., minimum acceptable expected rate of return, or "hurdle rate") for such a firm's investments goes as follows:

(1) The firm is one of a class with similar risk characteristics—call this class j.

(2) At any point in time there is a unique expected rate of return prevailing in capital markets for this degree of risk—call it R_j.

(3) The share price of the firm in question will adjust so that it offers an expected rate of return R_j to investors.

(4) This rate, the shareholders' opportunity cost, should be the minimum acceptable expected rate of return on new investment, assuming the projects under consideration have risk characteristics similar to currently held assets. Otherwise, the firm's shareholders' wealth will not be maximized.

This sequence of logic defines the appropriate discount rate for projects which do not change the firm's risk characteristics. The basic problem is one of estimating the rates prevailing in the market.

The following equilibrium condition will be assumed to define R_j:

$$P_{tj} = \frac{D_{t+1,j} + P_{t+1,j}}{1 + R_j}, \qquad (1)$$

where

$$P_{tj} = \text{ex-dividend price at the end of period } t;$$
$$D_{t+1,j} = \text{dividends[10] expected to be received in } t+1, \text{ and}$$
$$P_{t+1,j} = \text{expected ex-dividend price at the end of } t+1.$$

It is not literally true that everyone has the same expectations of future returns. However, for purposes of analysis I assume that it is permissible to speak of "the market's" expectations.

Also, note that if R_j is assumed constant over time,[11] equation (1) implies

$$P_{0j} = \sum_{t=1}^{\infty} \frac{D_{tj}}{(1 + R_j)^t}. \tag{2}$$

☐ **Additional comments.**

Risk classes

The phrase "risk class" does not strictly imply that risk can be measured in one dimension. Moreover, it is conceivable that equilibrium expected rates of return on securities depend not only on risk but on still other factors, although this has not been established.

Nevertheless, the concept of opportunity cost (relative to an equivalent class of securities) is not made invalid by the fact that it may have to be defined as a function of several variables.[12] It is true, of course, that the more complicated the function, the more difficult is use of the concept.

Evaluating investments in differing risk classes

Most of the analysis in this paper assumes that the firm's risk class is given. However, what happens if it is not?

Suppose the firm acquires or disposes of an asset or liability, and that the transaction changes the firm's risk class from j to w. Assume that the asset or liability considered separately is in class k. Then in perfect markets,

$$P_{wt} = \bar{P}_t + \Delta P_t = \frac{\bar{D}_{t+1} + \bar{P}_{t+1}}{1 + R_j} + \frac{\Delta D_{t+1} + \Delta P_{t+1}}{1 + R_k}, \tag{3}$$

where $^-$ indicates initial values and Δ, changes due to adoption of the

---

[10] "Dividends" must be broadly interpreted to include all cash flows from the firm to holders of the share in question. Conceivably, D_t might include return of capital or even direct repurchase of shares by the firm.

[11] This assumption avoids consideration of the term "structure of interest rates." It also assumes that the perceived risk of successive future dividends increases at a constant rate as a function of t. See Robichek and Myers [40].

[12] For example, the different tax treatment of capital gains vs. dividends implies, *ceteris paribus*, that equilibrium expected rates of return should be positively correlated with dividend yield. If so, this would add another dimension necessary to define a class of equivalent securities. However, it is not clear whether there is any systematic empirical relationship between dividend yield or payout and equilibrium rates of return. See, for example, Friend and Puckett [15], Miller and Modigliani [30], especially p. 370, and Black and Scholes [6]. Others, notably Gordon, have argued that equilibrium rates of return are negatively related to dividend payout. See [16], for example.

project in class k.[13] Alternatively,

$$\Delta P_t = \sum_{t=1}^{\infty} \frac{\Delta D_t}{(1 + R_k)^t}, \tag{4}$$

where ΔD_t is the expected incremental cash flow from adoption of the project. Thus, if the asset or liability under consideration has risk characteristics like securities in class k, then the appropriate opportunity cost is R_k, the equilibrium rate of return offered by class k securities.

4. Estimating the cost of capital

■ This paper does not go very deeply into the problem of estimating investors' opportunity costs. However, a brief review will be helpful in two ways. First, it will show the kinds of evidence likely to be relied on in a practical context. Second, it will show some of the implications of the view of security valuation presented in Section 3 above.

The basic proposition underlying the cost of capital concept is that at any point in time securities are so priced that all securities of equivalent risk (i.e., all securities in a "risk class") offer the same expected rate of return. For a given utility the basic problem is to determine the expected rate of return for the class in which the stock falls.

There is no mechanical way to do this. Measurement of expectations is intrinsically difficult. But there are several types of evidence that should be examined before the ultimate judgment is made.

1. *Interest rates*

Interest rates on corporate bonds and other debt instruments can be readily observed to provide a floor for the estimate. Changes in the basic level of interest rates normally correspond in direction to changes in the cost of equity capital.

2. *Ex post rates of return to investors*

Averaging of *ex post* rates of return (or better, of *ex post* risk premiums, since interest rates vary over time) give some indication of the relevant range in which expectations lie. These averages are most helpful to the extent that they cover a long period of time and many stocks.[14] One cannot very well rely on five years of history for the utility in question as a guide to investors' expectations for the future.

3. *DCF formulas*

Examination of interest rates and past rates of return indicates a range for expected rates of return on common stocks. But these measures give insufficient bases for estimating a particular firm's cost of equity capital.

---

[13] The theorem is proved in a more general form in Myers [36]. There are, of course, degrees of perfection, and there is a residual disagreement about how perfect markets have to be in order for equations (3) and (4) to hold. See Lintner [23], p. 108, and on the other hand, Hamada [19].

[14] There is plenty of evidence available. See, for instance, Fisher and Lorie [13].

One approach is the so-called DCF or discounted cash flow method.[15] Its basic premise is equation (2)—i.e., that stock price is the present value, discounted at R, of the stream of expected dividends.[16] The idea is to infer R from the observed price P_0 and an estimate of what investors expect in the way of future dividends.

In practice a number of simplifications of equation (2) are employed in using the DCF method. Suppose, for example, that the dividend stream is expected to grow indefinitely at some rate g which is less than R. Then equation (1) can be simplified to

$$P_0 = \frac{D_1}{R - g}, \tag{5}$$

$$R = \frac{D_1}{P_0} + g\,. \tag{5a}$$

For utilities, for which a constant, moderate long-term trend in earnings and dividends is often identifiable, equation (5a) can be a reasonable rule of thumb for estimating R. A danger is that temporary growth trends are apt to be mechanically projected "to infinity." Likewise, it is tempting to assume without checking that expected future growth is constant. Fortunately, there is nothing in equation (2) that requires a single, perpetual growth rate. One can easily assume that different growth rates are anticipated for different future periods.[17]

In general, the DCF model—either equation (5a) or some more complicated variant of equation (2)—has to be fit to the case at hand. The point of the analysis is to answer the question, What would a rational unbiased investor expect from a long-term investment in this stock at the prevailing price? This rate of return is taken to be R on the assumption that the prevailing price is based on the opportunity cost of investment in equivalent-risk securities.

4. *Earnings-price ratios*

Earnings-price ratios can be used to measure the cost of equity capital in some cases. The formulas

$$P_0 = \frac{\text{EPS}_1}{R}, \tag{6}$$

$$R = \frac{\text{EPS}_1}{P_0} \tag{6a}$$

are actually special cases of equation (2) if certain assumptions hold.

Suppose that earnings per share (EPS) in any one year are "normal" long-run earnings of the firm's business and that all earn-

[15] For examples of the use of the method, see testimony of Brigham [55], Kosh [52], Myers [53, 61], and Roseman [57].

[16] The subscript j has been dropped because the firm's risk class is taken as given.

[17] In [61] I used a simple structural model of the firm to project the dividend stream under different assumptions about the short-term growth, long-term growth, and year-by-year book profitability. The dividend stream and the final estimate of the cost of equity capital were based on these simulations.

ings are paid out as dividends. Then equations (6) and (6a) are simply equations (5) and (5a) but with $g=0$.

Thus it is said that EPS_1/P_0 measures the cost of equity capital for "no-growth" firms. This is possibly misleading, however. Suppose a firm which falls initially into the no-growth category instead reinvests a portion of its earnings in projects which have on the average a present value of exactly zero. Then announcement of these projects makes the firm no more nor less attractive to investors, even though the firm will expand because of the reinvested earnings. The firm's current stock price will not change. Therefore, R is still correctly measured by EPS_1/P_0.

If the projects are on the average more than marginally desirable, however, the price will rise, earnings per share will remain constant, and thus the earnings-price ratio will underestimate R.

Note that equation (2) can be written

$$P_0 = \frac{EPS_1}{R} + \sum_{t=1}^{\infty} \frac{D_t - EPS_1}{(1+R)^t}. \tag{7}$$

The second term can be interpreted as the net present value of future growth opportunities. Equation (6) follows from equation (7) only if the second term equals zero—i.e., if the firm's future investments yield exactly R on the average.

We see that growth in itself does not invalidate equations (6) and (6a). What does invalidate the formulas is growth that is more or less than minimally profitable.

This result has an interesting practical implication. Suppose it is argued that a utility's earnings-price ratio underestimates R. Then it must also be argued that investors expect the utility to earn more than the cost of equity capital on its future investments.[18]

☐ **Measuring risk.** It is clearly better to estimate R from data from a sample of equivalent-risk companies, rather than from data pertaining to the utility in question. But this requires an operational definition of "equivalent risk."

There is no consensus as to how risk should be defined and measured. Nevertheless, it is possible to obtain, from historical data, one or two statistics that are widely used as proxies.

The risk measures most often used stem from Markowitz's formulation of the individual's portfolio selection problem.[19] The investor is assumed to balance R_p, the expected one-period return on his portfolio, against $\sigma_p{}^2$, the variance of R_p. Let x_i equal the proportion of his investment allocated to security i, one of N candidates. Let σ_{ik} be the covariance of R_i and R_k and let $\sigma_i{}^2 = \sigma_{ii}$. Then

$$R_p = \sum_{i=1}^{N} x_i R_i, \tag{8}$$

[18] This assumes that EPS_1 equals expected average earnings from assets held in $t = 1$. EPS_1 may differ from earnings as actually reported.

[19] See Markowitz [28]. For more extended treatment of the concept and its applications, see Markowitz [29] and Sharpe [45].

$$\sigma_p{}^2 = \sum_{i=1}^{N} \sum_{k=1}^{N} x_i x_k \sigma_{ik} \tag{9}$$

with $\sum x_i = 1$.

Consider the special case in which the portfolio is limited to one security. For such an undiversified investor the relevant risk of security i is simply $\sigma_i{}^2$. Thus, if it is believed that demand for utility z's shares stems predominantly from undiversified investors—the proverbial widows or orphans who own stock in at most a few firms—then an estimate of $\sigma_z{}^2$ from past data should be a reasonable risk proxy, and a class of equivalent risk securities could be defined by $\sigma_i{}^2 \cong \sigma_z{}^2$.

However, it is hard to believe that the special case of widows and orphans is dominant. In general, the risk of security i is its marginal contribution to $\sigma_p{}^2$. This is

$$\frac{\delta \sigma_p{}^2}{\delta x_i} = 2x_i\sigma_i{}^2 + 2 \sum_{k \neq i} x_k \sigma_{ik}$$

$$= 2 \sum_{k=1}^{N} x_k \sigma_{ik} = 2\sigma_{ip} \, . \tag{10}$$

Thus security i's risk is proportional to σ_{ip}, the covariance of R_i and R_p.

As the number of securities in a portfolio increases, R_p becomes more and more closely correlated with R_M, the return on the "market portfolio" composed of all securities. (In fact, a high correlation of R_p and R_M has been found for randomly selected portfolios consisting of as few as ten stocks.)[20] This suggests σ_{iM} as an indicator of the "systematic" or "undiversifiable" risk of security i—the risk relevant to a diversified investor. σ_{iM} is in turn proportional to the coefficient β_i in the linear regression equation

$$R_i = \alpha_i + \beta_i R_M \, , \tag{11}$$

since β_i is given by $\sigma_{iM}/\sigma_M{}^2$.

Now, β_i can be estimated from past data. Thus it is a natural proxy for the effective risk of security to the well-diversified investor.

There is disagreement about the relative importance of β_i and $\sigma_i{}^2$ as determinants of R_i, but one and/or the other capture most of what most economists understand as risk.

☐ **The capital asset pricing model.** The risk measure β_i was just "derived" on a pragmatic basis, in order to show that it is *one* reasonable risk measure even in the absence of a formal theory of how risk affects security prices. Such justification is available, however, in the so-called capital asset pricing model.[21] Suppose we assume:

(1) That investors have identical assessments of securities' expected returns and risk characteristics,

(2) That the Markowitz model describes their portfolio choice, and

(3) That they can borrow or lend at a given risk-free rate, R_F.

---

[20] See Evans and Archer [11].

[21] The model is due to Sharpe [44], Lintner [24, 25], and Mossin [35].

Then at equilibrium in perfect markets,

$$R_i - R_F = \beta_i(R_M - R_F)\,,$$
$$\beta_i = \frac{\sigma_{iM}}{\sigma_M{}^2}\,. \tag{12}$$

It is not clear that equation (12) provides a *complete* empirical explanation of asset valuation.[22] But it does lend additional support to the use of β_i as a risk measure.[23]

Note also that if equation (12) is accepted it provides a vehicle for estimating R_i. R_F is approximately observable—a Treasury Bill rate, or a prime commercial paper rate, is customarily used. And presumably R_M, or $R_M - R_F$, will be easier to estimate from historical data than R_i or $R_i - R_F$. However, this approach has not yet been used in a regulatory proceeding.

☐ **Further comments on estimation in practice.** It is not my intention to go very deeply into practical problems of estimation. Nevertheless, a few comments may help to put the material just presented in better perspective. The problem is assumed to be estimating the opportunity cost of stockholders in Utility X.

It would be nice if investors' expectations were readily observable. If they were, they would surely be reported in the financial pages; and estimating R for Utility X would be a matter of looking up the currently projected dividends and capital gains, observing X's price, and calculating a rate of return. This would be taken as R_x on the assumption that X's stock is accurately priced relative to alternative equivalent risk investments. A sample of one firm (X) would be sufficient.

This is a never-never land. Suppose, however, we start with a sample of one firm, then postulate that a utility's future growth is relatively stable and predictable, and that it is therefore reasonable to use past trends as proxies for investors' expectations.

1. DCF estimates

Take the case of AT&T.[24] In March 1971 its annual dividend was \$2.60, the share price about \$49, and the dividend yield 0.053. During the 1960s the growth trend in its earnings per share was 4.6 percent. The trend in dividends per share for the same period was 4.5 percent. Suppose equation (5a) applies. If investors expected continued growth at about 4.5 percent per year, then their expected rate of return must have been $0.053 + 0.045 = 0.098$, that is, about 10 percent.

But it is immediately clear that the future need not be like the past. For example, AT&T's total assets may grow at a different rate,

---

[22] See Friend and Blume [14] and the several empirical studies in Jensen [20].

[23] Equation (12) also suggests that $R_i - R_F$ and $R_M - R_F$ should be substituted for R_i and R_M in estimating equation (11). Even if equation (12) does not hold exactly, security returns at any point in time depend on R_F, and a more reliable estimate of β_i can be obtained if fluctuations in R_F over time are adjusted for.

[24] The numerical examples following are drawn from my recent testimony [53]. I am not trying to summarize that testimony, nor am I implying that what was done there is necessarily appropriate for other cases. I am using that testimony here as a convenient source of numerical examples.

TABLE 2

COST OF EQUITY CAPITAL ESTIMATES BASED ON SIMULATION MODEL

AVERAGE BOOK RATE OF RETURN ON EQUITY INVESTMENT	LONG-TERM GROWTH RATE OF BELL SYSTEM ASSETS			
	0.07	0.08	0.09	0.10
0.100	0.097	0.098	0.098	a
0.105	0.101	0.102	0.103	0.104
0.110	0.106	0.107	0.108	0.109
0.115	0.110	0.111	0.112	0.113
0.120	0.115	0.116	0.117	0.118
0.125	0.119	0.120	0.121	0.122

[a] NO MEANINGFUL FIGURE EXISTS FOR THIS CASE.

SOURCE: SIMULATION RUNS, DESCRIBED IN [53], APPENDIX B.

and it may be more or less profitable. Since investors took such facts into account in their assessments of expected future earnings and dividends, equation (5a) may not apply.

2. Simulations

The obvious next step is to explore the consequences of alternative assumptions about the future performance of AT&T.

Table 2 shows the long-run rate of return from investments in AT&T stock at $49, under various assumptions about book rate of return on equity (ROI) and long-term asset growth (g_A).[25]

Table 2 should be read in the following way: If investors expect $g_A = 0.08$ and ROI = 0.10, then the cost of capital is 0.098, roughly the same as estimated previously via equation (5a). However, if investors expect $g_A = 0.08$ and ROI = 0.115, then the cost of equity capital must be 0.111; otherwise AT&T's stock would not sell for $49.

Thus, to the extent that it is possible to establish a reasonable range for investors' expectations of asset growth and book profitability, it is possible to specify a range for the cost of capital. For example, if there is no evidence that could justify an expectation of ROI > 0.12 or $g_A > 0.09$, then R must be less than 0.117.

Note that the cost of equity capital estimate increases with the assumed growth in assets. The higher g_A, the greater the present value of growth opportunities (ROI $> R$ in all instances) and the greater the cost of capital needed to explain the observed share price. However, the cost of equity capital estimate is much more sensitive to ROI than g_A, which reflects an interesting problem peculiar to regulated firms. The range of possible variation in ROI is wide partly because of uncertainty about the behavior of AT&T's various regulators. Granted, some of the more extreme values in Table 2 might be rejected as estimates of investors' *expectations*, but the uncertainty persists. This is one more reason why testimony in a regulatory proceeding cannot rest on a sample of one firm. The regulatory process

[25] The table is based on a simulation which is described in detail in [53], Appendix B. The simulation was necessary because of the complexity of the relationship between g_A, ROI, and the projection of dividends and earnings per share. The major complicating element was the necessity for periodic stock issues to finance asset growth at g_A.

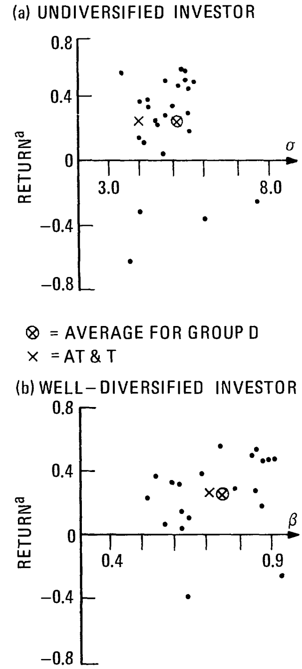
introduces an element of uncertainty, which makes it difficult to assess investors' expectations, and thereby makes it difficult to measure the cost of capital. It is obviously necessary to broaden the sample.

3. Risk classes

However, broadening the sample requires specification of a risk-equivalent class of stocks. Suppose we make use of the risk proxies described above. Figure 1 plots *ex post* return versus σ and β, respectively, for AT&T and Moody's 24 utilities, a sample of large, well-established electrics. The points shown were calculated from monthly rate of return data covering the 1960–1969 period.[26]

FIGURE 1

RETURN VS. RISK FOR AT&T AND STOCKS IN GROUP D



[a]DEFINED AS THE AVERAGE RISK PREMIUM EARNED, 1960-1969, BASED ON MONTHLY DATA. THE TREASURY BILL RATE WAS USED AS THE RISK–FREE RATE OF INTEREST. FOR FULL DETAILS SEE [53], PP. 49-57 AND ATTACHMENTS H THROUGH N.

The figure shows that, compared to these utilities, AT&T was a relatively safe investment for the undiversified investor. For a well-diversified investor AT&T's risk was about the same.

Suppose that the 24 electrics are accepted as an "equivalent risk class." The logical next step is to estimate the cost of equity capital for the utilities. There are several ways in which this could be done. We might observe the average dividend yield of the 24 utilities (0.054) and the average of their 1960–1969 trends in earnings per share (0.06). Then using equation (5a),

$$R = \frac{D_1}{P_0} + g$$
$$= 0.054 + 0.06 = 0.114 \,.$$

4. The role of judgment

One can go on to consider other companies, other measures, and other time periods. The only solid generalization is that, at the present state of the art, the final figure for cost of equity capital will be a judgment based on a wide variety of data and techniques. Such judgment is customary in regulatory proceedings; it is not peculiar to estimates of market-based costs of capital. The important point is that judgmental estimates of R do not have to be shots in the dark. One can arrive at rough but plausible estimates of R by using the simple tools I have just described.

5. Econometric models

The persuasiveness of "judgmental factors" in cost of capital estimates creates a clear opportunity for effective use of econometric models. Such models may improve the accuracy of the estimates and certainly will make the required judgments more explicit.

There are many recent attempts to estimate the cost of capital via econometric techniques,[27] but the approaches taken are so diverse

[26] *Ibid.*, pp. 49–57 and Attachments H through N. Since Figures 1(a) and 1(b) are used here only for illustrative purposes, I do not think it necessary to include all of the backup material.

[27] The list includes Miller and Modigliani [30] and the subsequent comments and elaboration on their approach [8], [17], and [42]; Gordon's work for the FCC [51], of which a new version is in preparation; also, Brigham and Gordon [7], McDonald [27], Litzenburger and Rao [26], and others.

that it is impossible to review the field here. More of a consensus will probably have to be reached before such models are routinely used. So far, Gordon's model[28] is the only one presented as evidence in a major regulatory proceeding.

5. Market efficiency and market perfection

■ There are two possible reasons for objecting to the use of the shareholders' opportunity costs in regulatory proceedings. The first is that they cannot be estimated with sufficient accuracy to support reasoned judgment by regulators. This objection cannot be answered *a priori*, but only by experience. The second objection is that data derived from stock market behavior are inappropriate for regulatory proceedings because of the market's irrationality or imperfection. This requires an answer.

□ **Efficiency of the stock market.** Some find it difficult to rest regulatory proceedings on something so volatile as the stock market. But this volatility is basically a reflection of the fact that most assets are risky; and to say that assets are risky means that their values will fluctuate. Uncertainty is a fact of life which happens to be more dramatically disrobed in the stock market than elsewhere. Therefore, the question is not whether the stock market is stable or predictable, since part of its function is to act as a locus for risk-bearing in the economy. The question is whether the market performs this function efficiently.

An "efficient" market is one in which at any point in time security prices fully reflect all information available at that point in time, and in which prices react quickly to new information as it becomes available.[29]

Efficiency can be defined more precisely. Rewriting equation (1) with more elaborate notation,

$$P_{jt}\,|\,\Phi_t = \frac{E(\tilde{D}_{j,t+1} + \tilde{P}_{j,t+1}\,|\,\Phi_t)}{1 + E(R_j\,|\,\Phi_t)}, \tag{1a}$$

where Φ_t is defined as a set of information. Equation (1a) defines the market's evaluation of j at t, given Φ_t. The market is efficient with *respect* to Φ_t if there is no way to use Φ_t to choose stocks with $E(\tilde{x}_{jt}) > 0$, where $\tilde{x}_{jt} = \tilde{R}_{jt} - E(\tilde{R}_{jt}\,|\,\Phi_t)$. Thus there are degrees of efficiency, depending on the breadth of information assumed included in Φ_t.

A relatively weak test is to define Φ_t as past price data and to predict that there is no superior trading strategy based on this information. Since past prices are certainly "available information," there should be no explainable price trends or cycles in an efficient market. This appears to be the case: no trading rule based on past prices has been shown to give abnormally high profits.

In fact, the evidence so far indicates that the U. S. capital markets are basically efficient with respect to a relatively broad set of information, including all data that would be regarded as publicly available. The evidence is ably summarized by Fama.[30]

---

[28] See [51].
[29] This discussion follows Fama [12].
[30] *Ibid.*

What relevance does this have for the use of finance theory in public utility regulation?

First, the market's efficiency is consistent with perfect markets—which are assumed here, and are usually built into theoretical models of valuation and the cost of capital.

Second, it indicates that observed prices at any time t approximate the equilibrium values, given Φ_t. Thus, an estimate of R at time t should be based on prices at t, not on an average of these and previous prices. There is no point in "smoothing" stock price series.

Third, market efficiency confirms that observed stock prices are closely coupled to information about the possible risks and returns of alternative investment opportunities. Otherwise a firm's "cost of capital" has little meaning or relevance. The measurement of a firm's cost of capital rests on the assumption that its stock is accurately priced relative to other equivalent-risk investments.

To summarize, there is positive evidence that overall capital market operations are basically efficient, and this efficiency is consistent with the hypothesis that market imperfections are minor.

6. Using the cost of capital as a basis for regulation

■ From this point I will assume that an estimate of Utility X's cost of capital is available. The problem is to determine how this figure should be used. I will continue to assume all-equity financing.

☐ **A straightforward approach: application to book value rate base.** I turn first to a simple and somewhat exaggerated example. Imagine a utility with book assets (rate base) of \$100 per share. It is all-equity financed. Earnings per share are \$16, all paid out as dividends. Earnings per share are expected to remain constant indefinitely.

Under such conditions, the earnings-price ratio (or the dividend yield) will measure shareholders' opportunity cost correctly. Suppose we observe a current price of \$200. Then

$$R = \frac{\mathrm{EPS}_1}{P_0} = \frac{D_1}{P_0} = \frac{16}{200} = 0.08\,.$$

How should the regulatory commission use this information? What I will call the "straightforward approach" is to allow earnings of 8 percent on the usual book value rate base. The price of a utility's product or service will be set at a level sufficient to yield profits of 0.08 (100) or \$8.00 per share.

If investors consider the new earnings level permanent, the utility's stock price will fall to \$100:

$$P_0 = \frac{\mathrm{EPS}_1}{R} = \frac{8.00}{0.08} = 100\,.$$

In other words, the straightforward application, in this idealized case, will drive share price to book value per share. The stock sold at \$200 in the first place only because the firm was then earning, and was expected to earn, twice the cost of capital.

A firm's market value will equal book value if it consistently earns a book rate of return equal to the cost of capital.

This example is not intended as a paradigm of ideal regulation. However, I do wish to respond to Ezra Solomon's contention that it and similar approaches are "inherently contradictory and inconsistent"[31] when there is a gap between the cost of equity capital and the book return actually being earned by the utility in question. Walter Morton has come to a similar conclusion:

> What is wrong with [the cost of capital] is that whenever it is applied to a price above book it must . . . cause a fall in earnings and a fall in the price of the stock.
>
> Any theory which postulates that investors pay above book, with the expectation that earnings will be cut as described by regulatory action, must assume either profound ignorance and ineptitude on the part of the investors, or a spirit of masochism which induces them to destroy their own capital.[32]

Actually, there is nothing inconsistent or illogical about the straightforward approach unless it is assumed that investors' expectations (as observed in the process of measuring the cost of capital) should always be confirmed when regulatory commissions act.

Take the simple example. Suppose that investors do not anticipate the rate reduction which forces earnings per share down to $8. The cost of capital is 8 percent both before and after the regulatory decision, so there can be no error or inconsistency in measurement. Rather, what happens is that the expectations investors hold before the regulatory decision (i.e., earnings per share of $16) turn out to be wrong in the event. But the regulatory commission is not bound to confirm investors' expectations. Therefore, the straightforward approach is logically sound. (Whether or not the regulators *should* force earnings per share down to $8 is, of course, another question.)

This discussion illustrates the dangers of using market value (as measured by share price) as a basis for setting earnings levels. The point is explicitly recognized in the Hope decision:

> The fixing of prices, like other applications of the police power, may reduce the value of the property which is being regulated. But the fact that the value is reduced does not mean that the regulation is invalid. . . . It does, however, indicate that "fair value" is the end product of the process of rate-making not the starting point. . . . The heart of the matter is that the rates cannot be made to depend upon "fair value" when the value of the going enterprise depends upon earnings under whatever rates may be anticipated.[33]

In short, "consistency" does not require that a market-based cost of capital must be applied to market value rate base. Actually, the problem with the straightforward approach is not one of inconsistency but of possible difficulties in measurement.

Suppose that market value is initially above book. The regulators announce that they will use the straightforward approach along with the DCF method of measurement. Share price will fall, since investors will anticipate a lower allowed rate of return after the Commission acts. On the other hand, if share price falls, the Commission will overestimate the cost of capital if they assume that investors expect continuation of past earnings. If investors, recognizing this, expect that the regulators will misread their (investors') expectations,

---

[31] Testimony of Solomon [60], transcript p. 1044.

[32] [33], p. 22.

[33] Note 1 *supra*, at 601.

TABLE 3

TEXAS EASTERN TRANSMISSION COMPANY— ACTUAL RATES OF RETURN ON EQUITY VS. RATES IMPLIED BY 6.5 PERCENT OVERALL RETURN

YEAR	RATES IMPLIED BY 6.5 PERCENT OVERALL RETURN	ACTUAL RETURN	DIFFERENCE
1965	11.10	14.03	+2.93
1966	10.65	14.44	+3.79
1967	9.98	15.10	+5.12
1968	9.38	16.25	+5.87

SOURCE: FPC DOCKET RP69–13 (PHASE I), INITIAL BRIEF OF COMMISSION STAFF [59].

then clearly, we have the beginnings of a very complicated game. Moreover, there is no guarantee that the players will arrive at a solution in which R is correctly measured.[34]

The solution to this measurement difficulty is not to rely on a sample of one firm, the utility in question, but on a broader sample of equivalent-risk firms.

☐ **Will share prices be forced to book value?** In our example, straightforward application of the DCF approach forces share price down to book value per share. This is generally true if the utility can actually be expected to earn the rate set for regulatory purposes. However, this is not always a safe assumption in practice.

This can be illustrated by the actual case of Texas Eastern Transmission Company for the 1965–1968 period. The firm's rate settlement in 1965 was on the basis of an overall rate of return of less than 6.5 percent. If Texas Eastern had actually earned 6.5 percent overall from 1965 through 1968, then it would have achieved the rates of return on book equity indicated in the second column of Table 3. The actual rates of return are shown in the third column.

Although it is difficult to infer exact causes, the fact that utilities can earn more or less than is nominally allowed appears due to four factors.

1. Regulatory lag

The existence of a regulatory lag is necessary but not sufficient. That is, if prices were immediately lowered (raised) whenever a

---

[34] Suppose that there is no growth trend in the utility's sales, profits, etc., and that the regulators measure R by the earnings-price ratio. Let BV be book value per share and ROI be the book rate of return. Let the superscript ^{0} indicate initial values. Thus, in the numerical example used in this section, $\mathrm{BV} = \mathrm{BV}^0 = 100$, $\mathrm{EPS}^0 = 16$, and $\mathrm{ROI}^0 = 0.16$. The regulators are assumed to set $\mathrm{ROI} = \mathrm{EPS}^0/P$, resulting in a new earnings-per-share of $\mathrm{EPS} = \mathrm{ROI}(\mathrm{BV}^0)$. If investors recognize this, $P = \mathrm{EPS}/R$. Thus we have three equations and three unknowns, EPS, ROI, and P. Solving for ROI, we obtain

$$(\mathrm{ROI})^2 = \mathrm{EPS}^0 \frac{R}{(\mathrm{BV}^0)}$$

or

$$(\mathrm{ROI})^2 = \mathrm{ROI}^0(R) .$$

Of course if $\mathrm{ROI}^0 = R$ then $\mathrm{ROI} = R$, but in this case the "game" will never begin. If the game does begin, then ROI^0 must differ from R and thus at the "solution" the new allowed ROI will not equal R either. In the numerical example, this solution will lead to $\mathrm{ROI} = 0.113$.

utility's realized return rose above (fell below) the allowed return, then the utility would always earn exactly the allowed return (assuming that there is *some* price which will generate the required profits). But the utility has an opportunity to earn more than the allowed return if regulatory surveillance is lax and/or there is delay in instituting new proceedings.

2. Cost trends

The tendency in regulatory proceedings is to estimate future costs per unit of output on the basis of past, or at best current, costs and output. The likely future changes in cost and output levels are not taken into account systematically. If cost trends are favorable—as a result of technological advances, for example, or of market growth when there are economies of scale—then regulatory lag will allow utilities always to stay somewhat ahead of the game.

3. Factors not under regulatory control

Clearly, if a utility has diversified into nonregulated fields, then restricting the profitability of the regulated portion is not sufficient to insure that the firm's book rate of return equals the cost of capital for the firm as a whole. A similar problem arises when different parts of a firm's operations are regulated by different bodies.

4. Changes in rate base relative to capacity and output

The size of a utility's book value rate base relative to its production capacity and output depends on the average age of its assets—that is, the older the assets the greater the proportion of the initial investment written off as depreciation. Thus, if capacity, output, and operating costs are constant, the utility's book rate of return will increase over time. The same phenomenon will occur if the utility's rate of asset expansion diminishes, other things constant.

Of course, these four factors may work against the utility as well as for it.[35]

In short, a straightforward application of the cost of capital to a book value rate base does not automatically imply that market and book values will be equal. This is an obvious but important point. If straightforward approaches did imply equality of market and book values, then there would be no need to estimate the cost of capital. It would suffice to lower (raise) allowed earnings whenever markets were above (below) book.

☐ **Mixing true and accounting rates of return.** Ezra Solomon has forcefully pointed out one major difficulty in regulatory procedures.[36] As matters stand now, regulation is based on utilities' book rates of return. The trouble is that book rates of return can be poor measures

[35] What about the "differences" shown for Texas Eastern in Table 3? My understanding is that they are due to favorable cost trends and profitable diversification into nonregulated industries. One "favorable cost trend" was a reduction in the effective income tax rate due to the investment tax credit. Incidentally, the rates of return on equity implied by a 6.5-percent overall return declined because embedded debt costs rose over the 1965–1968 period.

[36] Solomon [46]. See also Solomon and Laya [47].

of true (DCF) rates of return. The error's direction and extent can be an extremely complicated function of the firm's growth, the average maturity of its assets, its depreciation and capitalization policy, and inflation and other factors. Solomon concludes correctly that "the rate of return in conventional book rate units is conceptually and numerically different from the rate of return in DCF units," and that "two companies with similar DCF rates of return may well show widely differing book rates of return."[37]

Clearly, this is a potentially significant problem. How should regulatory decisions respond to possible biases in book rates of return? Do biases make use of cost of capital estimates inferior to rates of return based on traditional interpretations of the comparable earnings standard?

Suppose we accept that the possible biases are very difficult to estimate and adjust for. Then the traditional interpretation has an apparent advantage of consistency, in the sense that a utility's allowed book rate of return is compared to the book returns of other firms. However, consistency would also require that the utility's performance should be compared with the performance of firms whose book rates are subject to similar biases.

This only aggravates the problems in using the traditional interpretation. The firms most likely to have similarly biased book returns are other utilities. But their returns partly reflect past regulatory actions and thus do not provide an independent standard. Book returns of unregulated firms can be used, but such firms are likely to report book returns subject to different and possibly more severe biases than utilities' returns.

The alternative is to rely on the cost of capital concept. In this case regulators are faced with the possibility that the utility's apparent (book) rate of return may be different from the true (DCF) rate of return actually being earned by the utility.[38]

Evidently difficulties exist regardless of the interpretation of comparable earnings. At the present state of the art, the possible biases just discussed above provide no grounds for preferring the traditional interpretation of the comparable earnings standard to the interpretation presented here. The matter is ripe for further research.

---

[37] [46], p. 78.

[38] Actually, the difficulties which arise when this concept is relied upon seem to be more tractable—in the long run, at least—than if the traditional approach is used. The bias need be assessed for only one firm rather than for the broad sample of firms required to implement the traditional approach. It also seems likely that the regulatory process itself restricts the bias. If a regulatory commission decides to allow a return *R*, and adjusts the utility's prices frequently enough that the utility always earns *R* on a book basis, then the utility will earn the same true return *R*. It must be granted that regulation does not work this perfectly. There are lags and therefore some fluctuations in book returns with unknown effects on true returns. Allowed rates of return change from time to time. Inflation is a factor. The likely effects of all these items probably cannot be assessed without building a relatively detailed simulation model. Nevertheless, I think we can anticipate the likely results of such a simulation. The biases in the book return are associated with variation in individual assets' book returns over the assets' lives. The regulatory process diminishes this variation. Since its extent is probably much less for utilities than for manufacturing companies or other unregulated firms, the bias in utilities' book returns will probably be relatively small. This argument is made in more detail by Trapnell [49].

☐ **Inflation.** A book value rate base is the original cost of assets less depreciation. Neither component is adjusted to reflect experienced inflation, which raises two questions:

(1) Does fair play require an "inflation adjustment" to either the rate base or the allowed rate of return?

(2) Is such an adjustment required for efficient allocation of resources?

I consider only the first question here and defer the second until later on in the paper.

The classic formulation of the problems of regulation in inflationary times is Walter Morton's.[39] His answer to question (1) is yes. This answer rests on a value judgment—more precisely on an operational idea of fair treatment for utility investors.[40] Unfortunately, the requirements of "fair treatment" are not clearly defined in practice.

First, note that the cost of capital, as defined here, includes an adjustment for expected inflation. Investors' opportunity costs are estimated in nominal, not real, terms. Further, since "risk" here is related to uncertainty about nominal returns, it reflects uncertainty about future inflation and its possible effects on the regulated firm. (The effects depend in turn on the responses of regulators to various degrees of experienced inflation.)

One might visualize an implicit contract between investors and regulators, specifying the regulators' response to experienced inflation among other things. The question of whether investors are being treated fairly at any point in time depends on whether the implicit contract is being honored by the regulators.

Consider again the numerical example introduced at the start of this section. The cost of capital is 8 percent and the rate base is $100. Suppose the 8-percent rate of return includes investors' expectation of 2-percent-per-year inflation.

Thus the regulators allow earnings of 0.08(100) = $8. Price is

$$P_0 = \frac{\text{EPS}_1}{R} = \frac{D_1}{R} = \frac{8}{0.08} = \$100\,.$$

Now assume that there is actually 10-percent inflation in $t = 1$, 8 percent more than expected. However, by the start of $t = 2$, investors expect inflation to drop to the "normal" 2-percent-per-year rate. Then R is again 0.08 at the start of period 2 and, according to the straightforward approach, no adjustment in the utility's allowed return is necessary. Share price will remain at $100. The utility's shareholders' wealth is $108 per share at the start of $t = 2$, including earnings paid out during $t = 1$. Obviously their real rate of return is negative.

Is this fair? It depends entirely on whether the "contract" between regulators and investors calls for investors to absorb the risks of greater-than-expected inflation. In real life, the "contract" is so vague that there is very little ground for calling any regulatory strategy fair or unfair. However, the straightforward application of the cost of capital to the book value rate base is not unfair as long as it is applied consistently.

[39] See [33].

[40] See [34], p. 122 *ff.*

7. Finance theory and the goals of regulation

■ In the last section I considered several possible objections to use of utilities' costs of capital as a basis for their regulation. By and large the objections can be answered. But at best this shows that regulation *can* be based on finance theory; it does not show that it *should* be. Thus we must turn to a more fundamental question: What are the goals of rate of return regulation, and to what extent can these goals be met by procedures based on finance theory?

To some extent the specification of goals is a matter complicated by the necessity for value judgements. An investor who purchases shares of Utility X at $200 in good faith will feel cheated by any regulatory decision which hands him a $100 capital loss. On the other hand, regulators cannot be bound to confirm investors' expectations in all instances.

Finance and economics are not very helpful when the problem of regulation is framed as "consumers vs. investors." Instead I will assume that regulation is intended as a substitute for competition. Thus, a "fair return" will be defined in terms of the competitive standard.

□ **"Fair return" and the competitive standard.** Ideal regulation forces the utility to operate at competitive levels of investment, price, output, and profit.

This is difficult, perhaps impossible, to achieve in practice. Clearly, rate of return regulation can reduce or eliminate "monopoly profits;" but it is not so clear that such regulation produces the investments, outputs, or prices that would occur if a competitive solution could be achieved.

Moreover, in "naturally monopolistic" industries, with systematically decreasing average costs, a fully competitive market is not a realistic alternative. In this case, we might conclude that

> the function of regulation is to preserve for the public, instead of the producer, the benefits arising from legal monopoly without depriving the investor of a competitive profit.[41]

Thus it is natural to begin with the problem of eliminating "monopoly profits"—or, to put it more positively, the problem of providing the "fair" rate of return that would obtain in a competitive market.

What does "monopoly profits" mean? Suppose we observe an unregulated firm that has recently been very successful, one that has been able to earn more than its cost of capital. Are these high returns monopoly profits? Not necessarily: the firm may be in a competitive industry in which very high profits were not expected. (They were perhaps hoped for, but the hopes were balanced by fear of losses.) The rate of return actually being earned may be a pleasant surprise.

A superior rate of return will be a "short-run" phenomenon in competitive markets. Such a return will erode as markets shift towards long-run equilibrium. However, short-run profits or losses are more the rule than the exception. In real life the path of adjustment to long-run equilibrium will not be smooth, because of uncertainty and because the target itself will be continually changing.

In short, the theory of competitive markets provides no grounds for enforcing *ex post* equality of a utility's rate of return on assets

[41] *Ibid.*, p. 94.

and its cost of capital. It is more relevant to consider rates of return *ex ante.*

Long-run equilibrium in competitive markets implies that the average expected rate of return on new capital investment equals the cost of capital.[42] If the average expected rate of return does not equal the cost of capital then there will be entry or exit from the industry. Thus, if the aim is to eliminate monopoly profits, this principle follows:

Regulation should assure that the average expected rate of return on desired new investment is equal to the utility's cost of capital.

This principle follows if "fair return" is understood in terms of the competitive standard. If the principle is accepted, it obviously follows that rate of return regulation should be based on finance theory and the cost of capital concept.

□ **What "fair return" does and does not imply**. Before considering how to implement the principle, it will help to summarize some other things it does and does not imply.

(1) Note that an opportunity to invest in a project offering more than the cost of capital generates an immediate capital gain for investors. This is a windfall gain, since it is realized *ex ante.*

(2) A firm which can expect to earn its cost of capital on new investment meets the "capital attraction standard." This follows from the very definition of the cost of capital.

(3) Adherence to the principle implies that expected return to the equity owner is "commensurate with returns on investments in other enterprises having corresponding risks." Thus the principle is consistent with the comparable earnings standard established by the Hope case, provided that the standard is interpreted in terms of investors' opportunity costs.

(4) There are several things that the principle does not imply. It does not specify returns *ex post;* it is solely an *ex ante* concept. The existence of competitive markets does not require that expectations be realized for any asset, or even for all assets over any given period of time. Regulators can eliminate unexpectedly high or low rates of return after the fact, but only if they are willing to make the firm a risk-free investment.

(5) The principle says nothing about whether regulation should aim to make utilities safe or risky enterprises.

(6) Finally, it should be reemphasized that adherence to the principle does not guarantee that the utility will operate at competitive levels of price, output, and investment. This can easily be shown; it follows from the absence of any unique relationship between these variables and the *ex ante* rate of return on investment. There are many combinations of price, output, cost, and investment as well as many combinations of the various factors of production which will yield an expected rate of return equal to the cost of

---

[42] It is always true that the firm will invest up to the point where the marginal expected return on investment equals its cost of capital. This is so for both perfect competitors and monopolists, in both the short or the long run; thus, it provides no guidance for regulation.

capital. Further, there is no reason to suppose that the risk class the firm finally ends up in will be the same class that would prevail in a competitive environment.

☐ **Implementing the idea of fair return.** The principle that utilities ought to expect to earn the cost of capital on new investment is general enough to be compatible with a wide variety of regulatory schemes. Which one should be used? It is not yet possible to answer this question definitively. Nevertheless, a good deal can be said about the pros and cons of the most obvious alternatives.

In many ways the simplest approach is the "straightforward" approach with no regulatory lag. That is, the utility's product is priced at the start of each period t so that

$$REV_t = C_t + Z_t + R_t BV_t, \tag{13}$$

where

REV_t = anticipated revenues in t,
C_t = anticipated operating costs in t,
Z_t = depreciation to be charged in t,
BV_t = the rate base at the start of t—i.e., the book value of the utility's assets at that time, and
R_t = the utility's cost of capital measured at the start of t.

"No regulatory lag" means that the time from t to $t + 1$ is short enough so that deviations of actual, from anticipated, revenue and cost are not significant. Of course, it may not be easy to find a price such that equation (13) holds; both REV_t and C_t depend on output, which is in turn a function of price. But I will assume that regulators solve this problem somehow. Now consider the pros and cons of such a proposal.

Pros

First, the cost of capital will be relatively easy to measure, since a utility operating under the scheme just described will tend to be a very safe investment. The only uncertainties involve:

(1) Future changes in the cost of capital, and
(2) The possibility that there may be no price which will generate the required revenue.

It is hard to believe that an established utility facing only these uncertainties would have a cost of capital much greater than corporate bond yields. (Note that holders of corporate bonds also face the first source of uncertainty.)

Second, such a scheme would be easy to administer. The rate cases would be frequent, but routine.

Cons

There are, however, serious disadvantages. For one thing, a low cost of capital is not necessarily a good thing. There is no basis for assuming that, in a competitive market, uncertainty about operating costs would be borne almost entirely by consumers, as would be the case under this rule. Consequently, this is not likely to be an optimum allocation of risk bearing.

But the most serious item is that there is very little incentive for the utility to be efficient in choice of factor proportions, capacity, price and output, or technology. If the utility can expect to earn no more nor less than its cost of capital, then it has no incentive to seek efficiency along any of these dimensions.

It might be thought that a slight compromise of the principle—i.e., allowing the utility to expect to earn a rate R^* which is a bit greater than R—would establish the proper incentives. However, Averch and Johnson[43] have shown that the condition $R^* > R$ creates an incentive for firms to use more than the efficient amount of capital relative to other factors of production. Moreover, it is possible for the inefficiency in factor proportions to increase as the difference between R^* and R decreases.[44] Thus the compromise does not seem helpful, assuming use of the straightforward approach with no lag.

The charge of inefficiency is reinforced by Irwin Friend's argument,[45] which goes as follows. Suppose the utility is regulated by the straightforward approach, with no lag. Nevertheless, it is acting in good faith and trying to be efficient. The utility finds itself faced with a wide range of investment opportunities, some "good"—i.e., offering a rate of return greater than R—and some "bad." Efficiency would seem to call for taking only "good" projects. But this would lead to an average rate of return higher than R. Thus the utility might just as well forgo the good projects or balance them with bad ones.

In short, the straightforward approach sans lag has little to recommend it. It meets the standard of "fair return" but it accomplishes little else. In particular, it removes any incentive for efficient operating or capital budgeting procedures.

☐ **Conscious use of regulatory lag.** As I have now emphasized several times, firms in a competitive industry will not earn the cost of capital at all points in time. *Ex post* returns can deviate substantially from the cost of capital in the short run. The duration of the deviations will be limited by the time required by firms to invest (or dis-invest) and enter (or leave) the industry. A regulatory lag provides a short run in which utilities can earn unexpectedly high or low profits, and the rate proceeding at the end of the lag can play a role analogous to the forces which drive competitive industries towards long-run equilibrium.

Consider, then, regulation according to the straightforward approach but with *conscious* use of regulatory lag. I emphasize "conscious:" although there is inevitably a lag in practice, this does not necessarily imply a tolerance for surprisingly high or low rates of return. Rather, it seems to reflect a willingness to put off the next rate proceeding until profits get out of line.

With conscious use of regulatory lag, prices would be set and then left unchanged for several periods. Equation (13) would remain the starting point for determining the appropriate price. However, there are some additional complications. Suppose it turns out that trends in cost, technology, demand, etc. consistently favor the utility. Then

---

[43] See [1].

[44] See Baumol and Klevorick on this point [18], pp. 175–76. The Baumol-Klevorick article reviews the extensive literature on the Averch-Johnson thesis.

[45] See Friend [50] and [37], p. 4.

in principle the regulators should take account of the trends. That is, revenues allowed in t would have to be lower than REV_t as given by equation (13), so that

$$\sum_{\tau=t+1}^{t+L} \frac{REV_\tau - \overline{REV}_\tau}{(1+R_t)^{\tau-t}} = 0\,, \tag{14}$$

where

$\overline{REV}_\tau$ = revenues expected in τ, given the price set at t;
REV_τ = revenues expected to satisfy equation (13) in τ, and
L = anticipated length of the lag.

This condition is necessary for the utility to expect to earn the cost of capital on investments undertaken in t and subsequently.

Practical difficulties

The necessity for equation (14) means that the longer the lag, the greater the administrative difficulty. To some extent there must be regulation *ex ante*, which provides for endless argument. Moreover, the utility now has the incentive to overestimate future costs. These difficulties can be ignored, but only at the expense of possibly violating the principle that utilities ought to expect to earn the cost of capital on new investment.

Another disadvantage is the difficulty in determining the appropriate duration of the lag. This cannot be left entirely to the utility, because then the lag would be short when profits are low and long when they are high. Further, it makes sense to accept unexpectedly high profits for a relatively long time if they are due to unusual managerial efficiency, but to cut the lag short if the high profits stem from the exploitation of the utility's monopoly position. At best, the straightforward approach *cum* lag could not be a formula for regulation but only an approach to it.

Effects of the regulatory lag on efficiency

The existence of a regulatory lag clearly provides the utility with an incentive to improve efficiency. The incentive appears along several dimensions:

(1) Suppose the allowed rate of return equals the cost of capital. Bailey and Coleman[46] have shown that existence of a regulatory lag will induce the utility (a) to use factors of production in efficient porportions and (b) to produce more than would an unconstrained monopoly.
(2) Existence of a lag allows the utility to capture some of the rewards of managerial efficiency and of cost-reducing innovation.[47]
(3) The lag encourages efficient capital budgeting procedures. There is a positive incentive to avoid "bad" projects offering returns less than the cost of capital, and an incentive to disengage from "bad" projects previously undertaken.

---

[46] In [2]. Bailey and Coleman also show that the Averch-Johnson effects persist when there is a lag and the allowed rate of return is *above* the cost of capital.
[47] See Baumol and Klevorick [4], pp. 182–89.

Thus, although we cannot guarantee that a straightforward approach *cum* lag will lead exactly to the competitive solution, it does move the utility in the right directions. The inclusion of a lag does not make this strategy any more or less fair, but it makes the utility more efficient.

☐ **A tentative proposal.** The implications of the discussion so far can be summarized by offering a tentative proposal. Regulators should:

(1) Determine a price for the utility's product or service such that it can expect to earn its cost of capital, given the current cost and demand functions, rate base, and scheduled depreciation.
(2) Check to see whether the utility can be expected to earn more (less) than the cost of capital in subsequent periods, given the price set at $t = 1$. If so, lower (raise) the price so that the utility can expect to earn its cost of capital over the period of the anticipated lag.
(3) Tolerate unusually high or low profits during the period of regulatory lag. The length of the lag should roughly correspond to what the short run would be if there were a competitive market—that is, the length of time necessary to adjust the amount of fixed factors of production in response to changed conditions.

Admittedly, there would be compromises in practice. Because of administrative difficulties, step (2) would probably have to be skipped except in very clear-cut cases, and any adjustment would probably be based on judgment rather than explicit use of equation (14).

This proposal differs from current procedures primarily in the conscious use of regulatory lag. It is probably not the best strategy in any ultimate sense. There are many other strategies that are consistent with the principle that utilities ought to expect to earn their cost of capital on new investment; and it will be surprising if none among these turn out to be better, at least in theory, than the straightforward approach *cum* lag. Nevertheless, this proposed approach seems attractive pending rigorous examination of alternatives.

The search for alternative regulatory strategies might proceed in any one of several directions. One open question is whether use of a book value rate base leads to the best attainable regulatory decisions. This matter is briefly reviewed in the next section.

8. Determining the appropriate rate base

■ There are basically three different concepts of rate base that could be employed. They will be abbreviated as follows:

- BV Book value, based on the usual accounting principles.
- SMV Stock market value, i.e., number of shares outstanding times price per share.
- CMV Competitive market value, i.e., whatever the utility's assets would be worth at long-run equilibrium in a competitive market.

CMV can also be defined as the original cost of the firm's assets less economic depreciation. Similarly, BV equals original cost less accounting depreciation.

Some state commissions employ a fourth concept, the "fair value" rate base; but this need not delay us. In practice, fair value seems to be defined as book value plus a modest *ad hoc* adjustment.

Thus far, all I have said is that SMV is not useful in defining a utility's rate base. There are several reasons why. First, since SMV depends on how investors expect the regulators to act, it should be the "end result . . . not the starting point."[48] Second, adopting SMV as a rate base amounts to a commitment to confirm investors' expectations regardless of what they are based on. Third, if SMV is maintained consistently above (below) BV then the utility will expect to earn a rate of return on its new investment which is greater than (less than) the cost of capital.

But what about CMV as an alternative to BV?

□ **Determinants of CMV relative to BV**. The concept of a CMV rate base originates in the standard theory of competitive markets. It will help to review the determinants of CMV according to this theory.

Long-run equilibrium requires that the expected rate of return on a firm's CMV be R, its cost of capital. This must be true both in an average and a marginal sense. If the marginal return on the CMV of new assets is not R, then the firm's investment decision can be improved. If the average return on the CMV of all assets is greater than R, then there will be entry of new firms; if it is less than R, capital will be withdrawn from the industry.

There are several ways to state this formally, but the most useful starts with an analogue to equation (13):

$$REV_t = \pi_t Q_t = C_t + \hat{Z}_t + R_t \mathrm{CMV}_t , \qquad (15)$$

where

$\pi_t Q_t$ = equilibrium price times quantity to be produced during the period from t to $t + 1$,

$\hat{Z}_t$ = expected economic depreciation from t to $t + 1$,

C_t = expected out-of-pocket cost of producing Q_t, and

R_t = cost of capital measured at t.

Long-run competitive equilibrium requires that equation (15) holds when $\pi_t = \mathrm{LRMC}_t$, where LRMC represents long-run marginal cost. For simplicity, let us omit the t's. Then the following equation may be regarded as an implicit definition of the CMV of the firm's assets:

$$\frac{R(\mathrm{CMV}) + \hat{Z} + C}{Q} = \pi = \mathrm{LRMC} . \qquad (16)$$

That is, given the equilibrium price π, each firm's CMV will adjust so that equation (16) holds. Of course competitive equilibrium also requires that π = LRAC, long-run average cost.

Under these conditions, the CMV of any new asset is simply its purchase price. Suppose a firm invests \$100 in new assets during a given year. The firm is in a competitive industry which is at long-run equilibrium. We know that the expected rate of return on the 100th dollar must be R; consequently, this marginal dollar must contribute exactly \$1 to both CMV and BV. However, the average expected rate

[48] Note 1 *supra*, at 601.

of return on the \$100 invested must also be R; otherwise there would be an incentive for capital to enter or exit from the industry. Thus the other \$99 invested must contribute exactly \$99 to BV and CMV. The total CMV of the firm's "old" and "new" assets is determined by equation (16).[49]

Now let us carry equation (16) over into the regulatory arena as the definition of the CMV rate base. Under what conditions will a utility's CMV and BV rate bases differ?

The answer is clearest when we consider a utility that is started "from scratch." The utility's initial rate base is its gross investment outlay. For simplicity, assume scheduled book depreciation equals expected economic depreciation $\hat{Z}$. Then

$$\text{LRAC} = \frac{C + \hat{Z} + R(\text{BV})}{Q}. \tag{17}$$

Comparing equations (16) and (17), it is clear that CMV $\gtreqless$ BV as LRMC $\gtreqless$ LRAC.

This argument reflects the essential equivalence between use of a CMV rate base and LRMC pricing. That is, one way to test whether a firm's CMV differs from its existing BV rate base is to see whether there is a difference between (1) the price derived from straightforward application of the cost of capital to BV and (2) long-run marginal cost of new capacity, based on the most efficient available technology. If price is greater than LRMC, then BV is greater than CMV, and conversely. Thus, the straightforward approach based on CMV is exactly equivalent to (long-run) marginal cost pricing.[50]

☐ **Effects of using a CMV rate base.** It is obvious that regulation by the straightforward approach, under which the utility expects to earn the cost of capital on BV, cannot be expected to lead to the competitive solution unless BV = CMV—that is, unless accumulated book depreciation approximates economic depreciation.

There are no procedural difficulties in applying the straightforward approach *cum* lag to a CMV rate base, assuming that CMV can be estimated. (The estimation of CMV is difficult, particularly for utilities, but probably not impossible.)[51] Use of CMV would call for (1) an attempt to reflect expected economic depreciation in book depreciation schedules and (2) periodic write-ups or write-downs of the

[49] It is *not* determined by the reproduction cost of the old assets. If "reproduction cost" is used to define rate base, it must be in the sense of providing equivalent capacity with the latest equipment and procedures. But reproduction cost so defined is simply the CMV of the old assets.

[50] Here I ignore complications introduced by regulatory lag.

[51] The special complicating factors for regulated firms include the following:

(1) If a CMV rate base is used, the utility has an incentive to overdepreciate, thereby raising its price and increasing the immediate cash return. The excess depreciation could always be made up later by an *ad hoc* write-up of assets.

(2) A CMV rate base dilutes the utility's incentive to embrace technological change. Investment in radically more efficient assets, for example, would lead to a write-down of the value of old assets.

(3) In the case of unregulated firms, SMV may be a reasonable proxy for CMV. Unfortunately, the existence of regulation breaks the link between SMV and CMV.

rate base in response to unexpected developments.[52] However, strict use of a CMV rate base is *not* always consistent with the comparable earnings standard—that is, not always consistent with the proposition that the utility ought to expect to earn its cost of capital on new investment.

Consider again the case of the utility started from scratch. Suppose it is regulated according to a "straightforward approach" but with a CMV rate base. Then if LRMC is less than LRAC (the usual condition for a "natural monopoly") the utility can expect to earn less than R on its investment, since there will be an immediate write-down of the BV of this investment to CMV. Conversely, if LRMC > LRAC, then the utility's shareholders will receive an immediate capital gain due to a write-up of BV. Only in the case of LRMC = LRAC will this regulatory scheme adhere to the principle emphasized above, namely that a utility ought to expect to earn the cost of capital on its new investment.

It is interesting to compare this discussion with Klevorick's.[53] He found that maximization of social welfare will sometimes require that the firm be allowed to earn an average rate of return on investment that is different from the cost of capital. We have arrived at an essentially equivalent result by a somewhat more direct route. The result is that LRMC pricing (the usual condition for welfare maximization and efficient allocation of resources) will not yield an average return on investment equal to the cost of capital unless LRMC = LRAC.

☐ **Conclusions.** In one sense, this is a moot result, since plausible estimates of economic depreciation or LRMC have not yet been obtained. It is not clear whether a switch to CMV rate base would require a write-up or write-down of existing BV rate bases. It may turn out that average and marginal costs are roughly equal.

The immediate implication is that more thought is required on a variety of questions. For example:

(1) Can LRMC be measured in a practical context? That is, are there administratively feasible ways to construct economic depreciation schedules or CMV rate bases?
(2) Does LRMC in fact differ from LRAC? Does application of the cost of capital to utilities' actual BV rate bases result in prices substantially different from long-run marginal costs?
(3) If the answers to question (2) are yes, might it not be possible to have your cake and eat it too (i.e., to reconcile the conflict of marginal cost pricing with the comparable earnings principle) by adopting a two-part tariff? The "use" charge would be set equal to LRMC and the "capacity" charge then adjusted so that the utility expects to earn the cost of capital on its new investment.

---

[52] The write-ups and -downs of CMV would presumably lead to corresponding changes in SMV. However, stockholders could be insulated from these changes. If they were included in ordinary income, for example, about 50 percent of the effect would be offset by extra taxes or tax shields. Alternatively, the changes could be passed on to consumers via a one-time credit or charge. It makes little difference, from an economic standpoint, which scheme is used.

[53] See [21].

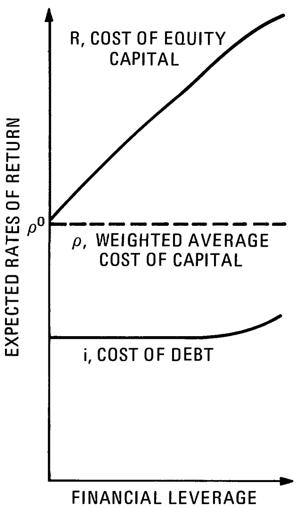
9. Regulating the overall rate of return

■ **Implications of finance theory.** The paper up to this point is an attempt to analyze—and to resolve, if possible—all the evident problems in applying finance theory to rate of return regulation. However, the analysis assumes that utilities are all-equity financed, which is of course not so. Thus it remains to be considered how a mixture of debt and equity financing alters the analysis. The first item is to review the theory and measurement of the cost of capital when capital structures include securities other than common stocks.

Measurement

FIGURE 2

EFFECTS OF FINANCIAL LEVERAGE ON COSTS OF DEBT AND EQUITY FINANCING AND THE WEIGHTED AVERAGE COST OF CAPITAL



Suppose we begin with a utility that is all-equity financed. If the utility now revises its capital structure to include some debt, the cost of equity capital (R) will rise, because financial leverage makes the firm's stock riskier. The interest rate, i, on the firm's borrowing will, of course, be less than the cost of equity capital. Figure 2 shows how R and i vary as a function of financial leverage. It should be intuitively clear that the utility's overall cost of capital, ρ, can be measured as a weighted average of R and i. It is not necessarily true that ρ will be constant, however.

Assume first that the firm's debt-equity mix is not expected to change. To get an exact measurement of ρ, given R and i, we can apply the same logic used to develop the cost of capital concept for the case of all-equity financing. Regardless of the degree of financial leverage, it is still possible to invest in the firm as a whole—i.e., in its assets, as distinct from any particular security. Investors can do this simply by purchasing each of the utility's financing instruments in appropriate proportions. Thus, suppose that the utility had \$100 million debt outstanding (market value) and outstanding stock with a market value of \$150 million. Then it would suffice to invest 40 percent of the portfolio in the utility's bonds and 60 percent in its stock.

Consider the opportunity cost of investors holding such a portfolio. The portfolio falls into a class of equivalent-risk securities and portfolios. If the expected rate of return for this class is, say, 10 percent, then the utility's stock price will adjust so that the portfolio of the utility's stocks and bonds will likewise offer an expected return of 10 percent. This 10-percent opportunity cost is the firm's overall, or "weighted average," cost of capital.

Thus, the overall cost of capital can be measured by the expected return on a portfolio of the firm's financing instruments:

$$\rho = i(D/V) + R(E/V), \tag{18}$$

where

i = current average yield to maturity of the firm's outstanding debt,

R = expected rate of return offered by the firm's stock—i.e., its cost of equity capital,

D = market value of the firm's outstanding debt,

E = aggregate market value of outstanding stock, and

$V = D + E$.

This assumes there are only two kinds of financing instruments, debt and common equity. But the weighting principle remains the same if there are others, such as preferred stock, subordinate debentures, convertible securities, etc. Of the variables used to compute the weighted-average cost of capital, only R, the cost of equity capital, is not directly observable. I have already discussed how it can be estimated.

Use of ρ as a rate of return standard

The overall cost of capital ρ is here defined as the opportunity cost of investing in a firm's *assets*. Therefore the concept and definition of ρ is the same regardless of whether the firm is financed entirely by equity or by debt and equity. The actual financing package must be taken into account in measuring ρ, but the firm's use of debt does not make measurement more difficult. Thus the conclusions reached in earlier sections of this paper are not at all dependent on the assumption of all-equity financing, provided the financing mix is taken as given. However, we face a whole new class of problems if the debt-equity ratio is expected to change. Clearly there will be a change not only in D and E, but also in R and possibly i and ρ.

Effects of changes in debt-equity ratios

The starting point in the analysis of changes in the financing mix is Modigliani and Miller's (MM's) famous Proposition I,[54] which states simply that V and ρ are constants, independent of leverage. The proposition depends on three assumptions:

(1) The existence of perfect markets;
(2) That changes in financial leverage do not affect the firm's assets, future investments, or the size and risk characteristics of its income stream; and
(3) The absence of corporate income taxes—or, alternatively, that interest charges are not tax deductable.

Figure 2 is drawn to conform with MM's Proposition I.

Let us consider the assumptions in the order stated. First, capital markets are not strictly perfect. It can thus be argued that imperfections are sufficient to negate Proposition I as an acceptable generalization. Durand's comment on MM[55] is a cogent presentation of this point of view, which is usually taken to imply that ρ is a shallow, U-shaped function of financial leverage, rather than the flat line drawn in Figure 2.

I will not discuss assumption (2) here.[56] It is not likely to be important except for firms that are levered to the point where there is a noticable probability of financial embarrassment. This is not the usual case for regulated utilities.

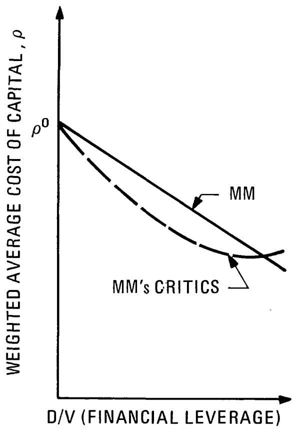
The tax effects are clearly substantial, however. In order to isolate them, we will assume that assumptions (1) and (2) are satisfied. Then MM's Proposition I implies, in general, that[57]

$$V = V^0 + \text{PVTS}, \tag{19}$$

[54] Modigliani and Miller [32].
[55] See [9].
[56] The role of factors covered by this assumption is treated in Robichek and Myers [41], especially p. 16, and Baxter [5].
[57] See Robichek and Myers [41], pp. 13–15.

FIGURE 3

EFFECTS OF FINANCIAL LEVERAGE ON THE WEIGHTED AVERAGE COST OF CAPITAL WHEN CORPORATE INCOME IS TAXED



where the superscript ^{0} indicates what the value of V would be if the firm were all-equity financed, and PVTS stands for the present value of tax savings due to the deductability of interest on the firm's debt. More specifically, suppose that the firm has no growth opportunities, so that equation (6) applies. Then

$$V = \frac{X(1 + T_c)}{\rho^0} + T_c D\,, \tag{19a}$$

where

T_c = the corporate tax rate,
ρ^0 = the firm's cost of equity capital if it were all-equity financed, and
X = the firm's expected income before interest and taxes.

This implies that ρ, as defined via equation (18), is also given by[58]

$$\rho = \rho^0 - T_c(\rho^0 - i)D/V\,. \tag{20}$$

The implied behavior of ρ vs. D/V is shown in Figure 3 by the downward-sloping solid line. To repeat, this assumes that MM's proposition I holds exactly except for tax effects—i.e., that the line would be horizontal in the absence of such effects.

If MM's critics are right, the true relationship is like the dashed line in Figure 3. Unfortunately, there is no theory for this case specifying an exact functional relationship comparable to equation (20). Therefore I will continue to use MM's equations for purposes of discussion.

Equation (20) applies regardless of whether the firm is regulated or not. This may seem surprising in view of the treatment of taxes in regulatory proceedings. The usual procedure is to treat a utility's tax bill as an operating cost. If taxes change, the price of the utility's product or service is adjusted to provide an offsetting change in revenue. Thus, if a utility issues more debt, thereby reducing taxes relative to equity financing, the tax savings will be passed on to consumers in the form of lower prices. However, this does not change either equation (19) or (20); but it does make X, earnings before interest and taxes, a function of D. Specifically, for a regulated firm,[59]

$$X = X^0 - T_c iD\,, \tag{21}$$

where X^0 equals earnings before interest and taxes if the utility is all-equity financed. For an unregulated firm, $X = X^0$.

To put it another way, both regulated and nonregulated firms benefit from debt via a lower cost of capital, ρ. But unregulated firms benefit further in that X is *not* decreased to offset tax savings, as is (presumably) the case for regulated firms.

☐ **Practical implications of possible changes in financial leverage.** The implications of all this can be summed up in Figure 3, in which the solid line represents equation (20) and the dashed line incorporates the effects of the market imperfections which MM's critics think are

---

[58] See Modigliani and Miller [31], p. 439.

[59] See Elton and Gruber [10] for a more detailed discussion of taxes and the regulated firm's cost of capital.

important.[60] However, there are implications for regulation regardless of which view is correct. One point is that a measurement of ρ on the basis of an observed capital structure will be in error if investors expect capital structure to change.

What is the possible magnitude of the error? Suppose equation (20) is right, and that a utility announces that it will shift D/V by 10 percent. Suppose that $T_c = 0.5$ and $\rho^0 - i = 0.05$. Then ρ will change by $T_c(\rho^0 - 1)\Delta D/V = 0.5(0.05)0.1 = 0.0025$, or 0.25 percent. In a practical context this is not a very large number, for several reasons:

(1) If MM's critics are right, and the utility's D/V ratio puts it in the trough of the dashed U-shaped curve in Figure 3, then ρ will change by less than equation (20) would indicate.

(2) It could easily take several years for a firm to shift its capital structure by 10 percent.[61]

(3) Any error in measuring ρ will persist only during the regulatory lag.

(4) To be sure, ± 0.25 percent may amount to a lot of dollars. But it would explain only a fraction of the differences in the proposed costs of capital presented by the various parties in an actual regulatory proceeding.

To summarize, it does not seem too dangerous to estimate a utility's cost of capital on the assumption of a constant debt-equity ratio. Although a planned, major, rapid shift in capital structure should be taken into account, such shifts are presumably more the exception than the rule.

☐ **Regulation of capital structure.** Now we may turn to a different problem: Should utilities' capital structures be regulated? At first glance, the objective of regulating capital structure would seem to be minimization of the weighted-average cost of capital. However, it is not at all clear that this is a good thing.

Suppose MM are right, so that equation (20) holds. Then ρ will decline with financial leverage, but only because the effect of the tax subsidy to debt financing is to reduce the risk of a portfolio of the firm's stocks and bonds. However, the firm's assets are no more nor less risky: It is simply that a part of the risk is absorbed by "we the people" via fluctuations in the corporate income tax revenues. Why should this be an objective of national economic policy?

If MM's critics are right, then ρ may also decline because of market imperfections. That is, the market imperfections will lead investors to prefer corporate debt to debt undertaken on personal account, and investors will therefore require, *ceteris paribus*, a lower expected rate of return on investments in levered firms. If this is the

[60] The following is a sampling of recent empirical studies, which contain references to earlier studies: Miller and Modigliani [30]; the "comments" on this piece [8], [17], and [42]; and Brigham and Gordon [7]; but see also Elton and Gruber [10], Sarma and Rao [43], and Litzenberger and Rao [26].

[61] For example, AT&T relied almost exclusively on debt for new external financing during the period 1967–1971. The effect was to shift its ratio of debt to total (book) capitalization from 33 to 45 percent. This was during a period of very heavy requirements for external finance. See Scanlon [54].

case, it is desirable for utilities to provide corporate leverage, since investors will thereby consider themselves better off. The trouble is that we do not know how strong investors' preference for corporate vs. personal leverage really is, if indeed this preference exists at all.

Thus, on purely economic grounds, the argument for regulating capital structure seems weak at best. About all that can be said is that utilities ought not to borrow so much that their solvency is endangered.

☐ **Some additional considerations.** The alert reader will have noticed two important differences between the overall cost of capital, as given by equation (18), and the procedure actually used by regulatory bodies in arriving at an overall rate of return allowance.[62] The differences are that

(1) Market value weights are used in equation (18), whereas book value weights are used in practice, and

(2) Embedded debt costs are used in practice.

What does finance theory say about the effects of these practices?

Clearly, the fact that the cost of capital can be applied to a book value rate base does not mean that book weights should be used in measuring it. The definition of the cost of capital in terms of investors' opportunity costs definitely implies that market value weights should be used.

This is not the whole story, however. Suppose Utility X is partly debt financed. Its regulators estimate ρ as 10 percent and therefore set X's prices so that the firm can expect to earn 10 percent on its book value rate base. X's stock sells for \$100 per share after all this is done. Now suppose that interest rates rise by 2 percent, and the firm's overall cost of capital rises from 10 to 12 percent. This leads to another rate hearing in which the utility is allowed 12 percent rather than 10.

Given the regulators' response, the increase in interest rates will not affect the total market value of the firm, $V = D + E$. However, bondholders will suffer a capital loss, which implies that shareholders will receive a capital gain. The rise in interest rates will lead to a capital gain on the initial share price of \$100. Conversely, if interest rates fall, bondholders will gain at the expense of stockholders.

Now, suppose that regulators wish to prevent stockholders from gaining when interest rates rise, and also wish to protect them from loss when interest rates fall. The way to do this is by allowing the firm to earn

(1) Its actual embedded interest cost, plus

(2) Equity earnings equal to the cost of equity capital times the book value of equity.

Under this procedure the overall rate of return will be a weighted average of embedded debt costs and the cost of equity capital, using book weights.

---

[62] See p. 61 *infra*.

To summarize, a regulatory strategy based on current debt costs requires market weights to compute the overall cost of capital. A strategy based on embedded debt costs requires use of book weights to determine the desired rate of return allowance. In general, the desired rate of return allowance in the latter case will not equal the overall cost of capital; that is, it will not generally reflect the current opportunity cost of investing in the firm's assets.

It is probably simpler, conceptually, to forget about embedded debt costs and simply use current borrowing costs. However, it is not necessarily illogical to use embedded costs. In fact, if there is no regulatory lag the use of embedded costs is generally consistent with the principle that utilities ought to expect to earn the cost of capital on new investment.[63] If utilities could change their rates automatically any time their embedded debt cost changed, then the rate of return earned on new investment would always reflect the actual current cost of any debt financing associated with the new investment.

But suppose there is a lag. Then if interest costs rise above embedded costs, a utility's rate of return on new investment will tend to be less than the cost of capital. The converse occurs when interest rates fall.

Conclusions

The use of embedded debt costs and book weights is not the most logical procedure. It seems simpler to rely on market weights and current interest costs, particularly when there is conscious use of regulatory lag. However, the straightforward approach *cum* lag is not necessarily incompatible with embedded debt costs and book weights, since the approach can be restricted to the equity component of utility capitalization. However, if the difference between current and embedded costs leads to a substantial violation of the principle that utilities ought to expect to earn the cost of capital in new investment, then an *ex ante* adjustment should be made.

10. Conclusions

■ This paper was motivated by dissatisfaction with the traditional interpretation of the comparable earnings standard, and by the hope that regulation could be made more effective by greater reliance on finance theory. Specifically, finance theory suggests that the comparable earnings standard should be defined in terms of investors' opportunity costs—i.e., in terms of utilities' costs of capital. Thus the paper is addressed to the question of whether regulation can or should be based on finance theory and the cost of capital concept. As we have seen, the search for an answer to this question requires consideration of a wide variety of topics in finance and the law and economics of regulation.

Is it in fact reasonable to base rate of return regulation on finance theory? It seems to me that the answer is a tentative yes. It is

[63] The timing of the change to current interest rates and market weights is a delicate matter. As this is written, current interest costs are substantially (1.5 percent or more) above embedded costs. A switch at this time would lead to a substantial capital gain for utility investors, financed by a one-time price increase. This raises problems of equity (to say nothing of politics), because it results from a change in the rules and is not a consequence of the regulatory process as consumers or investors have understood it.

tentative because there are difficulties (though the difficulties are often shared by other approaches to regulation) and because it is always possible that this paper will be made moot or obsolete by future developments in law, economics, or the conditions facing regulated firms.

Nevertheless there is a strong positive case to be made. I will close by summarizing it briefly:

(1) Regulation is usually regarded as a substitute for competition. If the definition of "fair return" is based on the theory of competitive markets, then regulation should assure that the average expected rate of return on new utility investment is equal to the utility's cost of capital. This is the ultimate justification for basing rate of return regulation on finance theory.

(2) This principle is consistent with the comparable earnings standard—in fact, more directly consistent than the traditional interpretation.

(3) There are many ways in which the principle can be implemented. Only the most obvious, "straightforward" approach was investigated here. But this approach is logically sound and practical. By and large, the objections to straightforward approaches can be answered satisfactorily.

(4) The straightforward approach is amenable to conscious use of regulatory lag. This does not make the approach more or less fair, but it does create stronger incentives for efficiency.

(5) The cost of capital is not directly observable, since it is defined in terms of investors' expected rates of return. At the present state of the art any estimate is part judgment. However, plausible estimates can be obtained, and the need for judgment is not evidently greater when regulation is based on finance theory rather than on traditional procedures.

The straightforward approach *cum* lag is not the final answer. It is only one of many ways to implement the principle that a utility ought to be able to expect to earn its cost of capital on new investment. Probably some of the other ways are better; it is hard to believe that the usual book value rate base could not be improved upon, for example. As a matter of fact, the whole existing framework of rate of return regulation, which was taken as given for purposes of this paper, may not be best. But all of this awaits further work.

References

1. Averch, H. and Johnson, L. L. "Behavior of the Firm Under Regulatory Constraint." *The American Economic Review*, Vol. 52, No. 5 (December 1969), pp. 1062–69.
2. Bailey, E. E. and Coleman, R. D. "The Effect of Lagged Regulation in the Averch-Johnson Model." *The Bell Journal of Economics and Management Science*, Vol. 2, No. 1 (Spring 1971), pp. 278–92.
3. Baumol, W. J. "Reasonable Rules for Rate Regulation: Plausible Policies for an Imperfect World," in *The Crisis of the Regulatory Commissions*, P. W. MacAvoy, ed., New York: W. W. Norton and Co., 1970.
4. ———, and Klevorick, A. K. "Input Choices and Rate of Return Regulation: An Overview of the Discussion." *The Bell Journal of Economics and Management Science*, Vol. 1, No. 2 (Autumn 1970), pp. 162–90.

5. BAXTER, N. D. "Leverage, Risk of Ruin and the Cost of Capital." *Journal of Finance*, Vol. 22, No. 4 (September 1967), pp. 385–404.
6. BLACK, F. and SCHOLES, M. "Dividend Yields and Common Stock Returns: A New Methodology." Unpublished Working Paper, Sloan School of Management, Massachusetts Institute of Technology, 1971.
7. BRIGHAM, E. and GORDON, M. J. "Leverage, Dividend Policy and the Cost of Capital." *Journal of Finance*, Vol. 23, No. 1 (March 1968), pp. 85–104.
8. CROCKETT, J. and FRIEND, I. "Some Estimates of the Cost of Capital to the Electric Utility Industry 1954–57: Comment." *The American Economic Review*, Vol. 59, No. 5 (December 1967), pp. 1258–67.
9. DURAND, D. "The Cost of Capital, Corporation Finance, and the Theory of Investment: Comment." *The American Economic Review*, Vol. 49, No. 4 (September 1959), pp. 639–55.
10. ELTON, E. J. and GRUBER, M. J. "Valuation and the Cost of Capital in Regulated Industries." *Journal of Finance*, Vol. 26, No. 3 (June 1971), pp. 661–70.
11. EVANS, J. L. and ARCHER, S. H. "Diversification and the Reduction of Dispersion: An Empirical Analysis." *Journal of Finance*, Vol. 23, No. 5 (December 1968), pp. 761–67.
12. FAMA, E. F. "Efficient Capital Markets: A Review of Theory and Empirical Work." *Journal of Finance*, Vol. 25, No. 2 (May 1970), pp. 383–417.
13. FISHER, L. and LORIE, J. H. "Rates of Return on Investments in Common Stock: The Year-by-Year Record, 1926–65." *Journal of Business*, Vol. 41, No. 3 (July 1968), pp. 291–316.
14. FRIEND, I. and BLUME, M. "Measurement of Portfolio Performance Under Uncertainty." *The American Economic Review*, Vol. 60. No. 4 (September 1970), pp. 561–75.
15. FRIEND, I. and PUCKETT, M. "Dividends and Stock Prices." *The American Economic Review*, Vol. 54, No. 4 (September 1964), pp. 656–82.
16. GORDON, M. J. *The Investment, Financing and Valuation of the Corporation.* Homewood, Illinois: Richard D. Irwin, Inc., 1962.
17. ———. "Some Estimates of the Cost of Capital to the Electric Utility Industry 1954–57: Comment." *The American Economic Review*, Vol. 57, No. 5 (December 1967), pp. 1267–78.
18. HAMADA, R. J. "The Effects of Leverage and Corporate Taxes on the Shareholders of Public Utilities," in *Rate of Return Under Regulation: New Directions and Perspectives*, H. M. Trebing and R. H. Howard, eds., East Lansing Michigan: Institute of Public Utilities, Michigan State University, 1969.
19. – "Portfolio Analysis, Market Equilibrium and Corporate Finance." *Journal of Finance*, Vol. 24, No. 1 (March 1969), pp. 13–32.
20. JENSEN, M., ed. *Studies in the Theory of Capital Markets.* New York: Praeger Publishers, 1972.
21. KLEVORICK, A. K. "The 'Optimal' Fair Rate of Return." *The Bell Journal of Economics and Management Science*, Vol. 2, No. 1 (Spring 1971), pp. 122–53.
22. LEVENTHAL, H. "Vitality of the Comparable Earnings Standard for Regulation of Utilities in a Growth Economy." *Yale Law Journal*, Vol. 74, No. 6 (May 1965), pp. 989–1010.
23. LINTNER, J. "Expectations, Mergers and Equilibrium in Perfectly Competitive Securities Markets." *The American Economic Review*, Vol. 61, No. 2 (May 1971), pp. 101–11 .
24. ———. "Security Prices, Risk and Maximal Gains from Diversification." *Journal of Finance*, Vol. 20, No. 5 (December 1965), pp. 587–613.
25. ———. "The Valuation of Risk Assets and the Selection of Risky Investments in Stock Portfolios and Capital Budgets." *The Review of Economics and Statistics*, Vol. 47, No. 1 (February 1965), pp. 13–37.
26. LITZENBERGER, R. L. and RAO, C. U. "Estimates of the Marginal Rates of Time Preference and Average Risk Aversion of Investors in Electric Utility Shares: 1960–66." *The Bell Journal of Economics and Management Science*, Vol. 2, No. 1 (Spring 1971), p. 265–77.
27. MCDONALD, J. G. "Required Return on Public Utility Equities: A National and Regional Analysis: 1958–1969." *The Bell Journal of Economics and Management Science*, Vol. 2, No. 1 (Autumn 1971), pp. 503–14.
28. MARKOWITZ, H. "Portfolio Selection." *Journal of Finance*, Vol. 7, No. 1 (March 1952), pp. 77–91.

29. ———. *Portfolio Selection: Efficient Diversification of Investments.* New York: John Wiley and Sons, Inc., 1959.
30. Miller, M. and Modigliani, F. "Some Estimates of the Cost of Capital to the Electric Utility Industry: 1954–57." *The American Economic Review*, Vol. 56, No. 3 (June 1966), pp. 333–91.
31. Modigliani, F. and Miller, M. H. "Corporate Income Taxes and the Cost of Capital: A Correction." *The American Economic Review*, Vol. 53, No. 3 (June 1963), pp. 433–43.
32. ———. "The Cost of Capital, Corporation Finance and the Theory of Investment." *The American Economic Review*, Vol. 48, No. 3 (June 1958), pp. 261–97.
33. Morton, W. A. "Guides to a Fair Rate of Return." *Public Utilities Fortnightly*, Vol. 86, No. 2 (July 2, 1970), pp. 17–30.
34. ———. "Rate of Return and the Value of Money in Public Utilities." *Land Economics*, Vol. 28 , No. 2 (May 1952), pp. 91–131.
35. Mossin, J. "Equilibrium in a Capital Asset Market." *Econometrica*, Vol. 34, No. 4 (October 1966), pp. 768–83.
36. Myers, S. C. "Procedures for Capital Budgeting Under Uncertainty." *Industrial Management Review*, Vol. 9, No. 2 (Spring 1968), pp. 1–20.
37. New York Public Service Commission. *New York Telephone Co.* Prepared Testimony, I. Friend. 1971.
38. Posner, R. A., "Taxation by Regulation." *The Bell Journal of Economics and Management Science*, Vol. 2, No. 1 (Spring 1971), pp. 22–50.
39. Rao, C. U. and Litzenberger, R. H. "Leverage and the Cost of Capital in a Less Developed Capital Market: Comment." *Journal of Finance*, Vol. 26, No. 3 (June 1971), pp. 77–82.
40. Robichek, A. A. and Myers, S. C. "Conceptual Problems in the Use of Risk-Adjusted Discount Rates." *Journal of Finance*, Vol. 21, No. 5 (December 1966), pp. 727–30.
41. ———. "Problems in the Theory of Optimal Capital Structure." *Journal of Financial and Quantitative Analysis*, Vol. 1, No. 2 (June 1966), pp. 1–35.
42. Robichek, A. A., McDonald, J. G., and Higgins, R. C. "Some Estimates of the Cost of Capital to the Electric Utility Industry 1954–57: Comment." *The American Economic Review*, Vol. 57, No. 5 (December 1967), pp. 1278–88.
43. Sarna, L. V. L. N. and Rao, K. S. H. "Leverage and the Value of the Firm." *Journal of Finance*, Vol. 24, No. 4 (September 1969), pp. 673–77.
44. Sharpe, W. F. "Capital Asset Prices: A Theory of Market Equilibrium Under Conditions of Risk." *Journal of Finance*, Vol. 19, No. 4 (September 1964), pp. 425–42.
45. ———. *Portfolio Theory and Capital Markets.* New York: McGraw-Hill Book Co., 1970.
46. Solomon, E. "Alternative Rate of Return Concepts and Their Implications for Utility Regulation." *The Bell Journal of Economics and Management Science*, Vol. 1, No. 1 (Spring 1970), pp. 65–81.
47. ———, and Laya, J. E. "Measurement of Company Profitability: Some Systematic Errors in the Accounting Rate of Return," in *Financial Research and Management Decisions*, A. A. Robichek, ed., New York: John Wiley and Sons, Inc., 1967.
48. Stigler, G. J. "The Theory of Economic Regulation." *The Bell Journal of Economics and Management Science*, Vol. 2, No. 1 (Spring 1971), pp. 3–21.
49. Trapnell, G. R. "Relationship of the Book Rate of Return on Investment to the Internal Rate of Return on the Investment and Implications for Utility Regulation." Unpublished Manuscript. Staff Paper 4, Office of the Actuary, Social Security Administration, 1971.
50. U. S. Federal Communications Commission. *American Telephone and Telegraph Co.* Prepared Testimony, I. Friend. F.C.C. Docket 16258, 1966.
51. ———. *American Telephone and Telegraph Co.* Prepared Testimony, M. J. Gordon. F.C.C. Docket 16258, 1966.
52. ———. *American Telephone and Telegraph Co.* Prepared Testimony, D. Kosh. F.C.C. Docket 19129, 1971.
53. ———. *American Telephone and Telegraph Co.* Prepared Testimony, S. C. Myers. F.C.C. Docket 19129, 1971.
54. ———. *American Telephone and Telegraph Co.* Prepared Testimony, J. J. Scanlon. F.C.C. Docket 19129, 1971.

55. ———. *Communications Satellite Corp.* Prepared Testimony, E. F. Brigham. F.C.C. Docket 16070, 1971.
56. U. S. FEDERAL POWER COMMISSION. *Area Rate Proceeding* (Offshore Southern Louisiana . . .) *et al.* Prepared Testimony, E. Solomon. F.P.C. Docket AR 69–1 et al., 1969.
57. ———. *Consolidated Gas Supply Corp.* Prepared Testimony, H. G. Roseman. F.P.C. Docket RP69–19, 1969.
58. ———. "Opinion and Order Determining Fair Rate of Return." F.P.C. Opinion No. 579, *Pacific Gas Transmission Corp*, F.P.C. Docket RP70–4 1970.
59. ———. *Texas Eastern Transmission Corp.* Initial Brief of Commission Staff. F.P.C. Docket RP69–13, 1969.
60. ———. *Texas Eastern Transmission Corp.* Prepared Rebuttal Testimony, E. Solomon. F.P.C. Docket RP69–13, 1969.
61. ———. *Texas Eastern Transmission Corp.* Prepared Testimony, S. C. Myers. F.P.C. Docket RP69–13, 1969.
62. WILLIAMS, J. B. *The Theory of Investment Value.* Amsterdam: North-Holland Publishing Co., 1968.

ENERGY INSTITUTE AT HAAS

Energy Institute WP 329R

Rate of Return Regulation Revisited

Karl Dunkle Werner and Stephen Jarvis

Revised March 2025

Rate of Return Regulation Revisited

Karl Dunkle Werner and Stephen Jarvis *

Abstract

Utility companies recover their capital costs through regulator-approved rates of return. Using a comprehensive database of utility rate cases, we find a significant premium for regulated returns on equity relative to several capital cost benchmarks. We show that firms decide strategically when to initiate new rate cases, such that regulated returns respond more quickly to increases in underlying capital cost benchmarks than to decreases. Higher regulated returns incentivize utilities to own more capital: a one percentage point rise in return on equity increases capital assets by 3–4%. Overall we find excess costs to US consumers averaging $7 billion per year.

JEL Codes: Q40, L51, L94, L95

Keywords: Utility, Rate of Return, Regulation, Electricity, Natural Gas, Capital Investment

* Dunkle Werner: Economic Policy, US Treasury, research@karldw.org.
Jarvis: Department of Geography and Environment, London School of Economics, s.jarvis@lse.ac.uk. The views and findings presented in this research do not necessarily represent the views of the US Treasury or any other author affiliation. The authors thank seminar participants at the Berkeley Electricity Markets group, the LSE Workshop in Environmental Economics, the POWER Conference and the AERE Summer Conference. The authors wish to acknowledge the advice of Severin Borenstein, Jim Sallee, and Meredith Fowlie. All errors are, of course, our own. Karl is grateful for the generous support of the Alfred P. Sloan Foundation Pre-doctoral Fellowship on Energy Economics, awarded through the NBER.

1 Introduction

In the two decades from 1997 to 2017, real annual capital spending on electricity transmission and distribution infrastructure by major utilities in the United States has more than doubled (EIA 2018a, 2018b). The combined total is now more than $90 billion per year (IEA 2023). This trend is expected to continue, both in the US and globally, with investment forecast to double or even triple by the 2040s (ibid).

These large capital expenses are generally viewed as utility companies modernizing an aging grid and making the necessary upgrades to support the clean energy transition underway in much of the sector. However, it is noteworthy that over recent years, utilities have earned sizeable regulated rates of return on their capital assets, particularly when set against the unprecedented low interest rate environment of 2008–2022. When the economy-wide cost of capital fell, utilities' regulated rates of return did not fall nearly as much. This gap raises the prospect that at least some of the growth in capital spending could be driven by utilities earning excess regulated returns. The distortion this can create to capital investment incentives has long been identified as a potential problem in the sector (Averch and Johnson 1962). More broadly, setting a fair rate of return is one of the core challenges for natural monopoly regulation of the utility industry (Joskow 1972, 1974; Joskow and Rose 1989).

In this paper we use new data to revisit these central issues of excess returns, capital ownership, and the political economy of utility regulation. We do so by exploring three main research questions. First, to what extent are utilities being allowed to earn excess returns on equity by their regulators? Second, what possible mechanisms can explain the divergence between regulated returns and underlying capital costs? Third, how have excess returns on equity affected utilities' capital investment decisions and the costs paid by consumers?

To answer our research questions, we use data on the utility rate cases of all major electricity and natural gas utilities in the United States spanning the past four decades. These investor-owned utilities serve three quarters of US consumers, and the regulated utility company model they operate under is the dominant industry structure in most advanced economies. We combine our rate case data with a range of financial information on credit ratings, corporate borrowing, and market returns. To examine possible sources of over-investment in more detail we also incorporate data from annual regulatory filings on individual utility capital spending.

We start our analysis by estimating the size of the gap between the allowed rate of return on equity (RoE) that utilities earn and some measure of the cost of equity they face. A central challenge here, both for the regulator and for the econometrician, is estimating the cost of equity. We proceed by simulating the cost of equity using the capital asset pricing model (CAPM). Using a range of standard financial assumptions we find a premium in approved returns on equity ranging from one to five percentage points over the past three decades. As an additional check we also examine benchmarks against various measures of debt yields and a comparison with regulatory decisions in the United Kingdom. Here again we find similar evidence of a large utility return on equity premium. Importantly, even our highest benchmarks tend to come in below the allowed rates of return on equity that regulators set today. By calculating a range of cost of equity benchmarks we go further than prior research in this area and take a stance on the size of the RoE spread, rather than just its likely existence or trending direction (Azgad-Tromer and Talley 2017; Rode and Fischbeck 2019). This is important for our subsequent analysis of the implications for capital investment and excess consumer costs.

The existence of a persistent gap between the return on equity that utilities earn and some measure of the cost of capital they face could have a number of explanations. Our benchmarking against the CAPM and recent work by Rode and Fischbeck (2019) rules out a number of financial explanations for the observed RoE spreads, such as changes to utilities' debt/equity ratio, asset-specific risk, or the stock market's overall risk premium. We also document a lack of meaningful changes in utility credit ratings over this period suggesting there have not been large changes in the riskiness of the utility industry. We therefore focus on a range of non-financial mechanisms, such as political concerns, behavioral biases, and regulatory capture. Directly attributing the relative importance of these different factors is challenging. However, our findings still shed new light on potential mechanisms and policy remedies, including several issues that have not been previously studied.

We start by examining the role played by the structure of the rate case process. To do this we turn to the literature on asymmetric price adjustments. It has long been documented that positive shocks to firms' input costs can feed through into prices faster than negative shocks (Ball and Mankiw 1994). Oil and gasoline markets have been the most heavily studied to date (Bacon 1991; Borenstein, Cameron, and Gilbert 1997; Perdiguero-García 2013; Kristoufek and Lunackova 2015), although similar features have been identified across a wide range of economic sectors, from agricultural products to financial markets (Peltzman 2000; Frey and Manera 2007; Gwin 2009). This is the so-called "rockets and feathers" phenomenon. To test whether this dynamic arises in our regulatory context we estimate a vector error correction model for the relationship between utilities' approved return on equity and some benchmark "input" measure of the cost of capital (e.g. US Treasury bond yields). Here we do indeed find novel evidence of asymmetric adjustment. Increases to the benchmark cost of capital lead to faster upward adjustments to utilities' regulated return on equity, while decreases lead to relatively slow downward adjustments. Our findings are the first instance we are aware of where this phenomenon has been identified in regulatory decision-making, rather than just in market prices.

One possible explanation for the asymmetric adjustment we observe relates to the timing of when rate cases are initiated and thus how long they last. Regulators face an information asymmetry with the utilities they regulate when determining whether costs are prudent and necessary (Joskow, Bohi, and Gollop 1989). Utilities have a clear incentive to initiate a new rate case and push for rate increases by claiming they face a high cost of equity that their shareholders must be compensated for. Conversely, they have little incentive to initiate a new rate case and push for a lower RoE if their actual cost of equity falls. If regulators are too deferential to the demands of the utilities they regulate we would expect rates to become detached from underlying costs. Here we find new evidence of strategic decision-making by utilities. When the existing regulated rate of return is advantageous to a firm, rate cases become longer. When the reverse is true, rate cases become shorter. Systematic changes in rate case timing and duration appear to have contributed to the higher rates of return utility companies have managed to secure.

This finding raises the question of why regulators would allow the rate case process to function in a way that systematically benefits the utilities they regulate. Prior work has highlighted the relative lack of resources and financial expertise at public utility commissions, making it hard for them to push back against the substance and urgency of arguments made by utilities (Azgad-Tromer and Talley 2017; Ellis 2025). This is at least partly reflected in the simple rules-of-thumb regulators sometimes use in the ratemaking process (Michelfelder and Theodossiou 2013; Rode and Fischbeck 2019). Consistent with this, we find evidence of whole number rounding in the approved rates of return set by regulators – a striking result given that fractions of a percentage point can mean millions in additional costs recovered from consumers. Regulatory capture is another longstanding concern that could play a role here, with perceptions of a "revolving door" between regulatory commissions and the utility industry (Dal Bó 2006; Heern 2023; Ellis 2025). Using our rate case data, we see correlational evidence that when regulators take a firmer approach by fully litigating cases, they tend to approve lower rates of return.

A final explanation we examine is whether regulators simply have alternative political objectives that are misaligned with setting cost-reflective rates (Aspuru 2024). For instance, regulators may try to avoid the political costs of increases in the overall level of gas and electricity prices faced by consumers, rather than setting rates that reflect underlying economic costs (Joskow 1974; Hausman 2019). If this is the case, we might expect utilities to be able to secure higher regulated returns during periods where other non-capital costs are declining. In these situations utilities capital costs could rise while the overall price faced by consumers remains relatively low. We find some limited evidence for this phenomenon, with more generous returns on equity tending to be approved by regulators during periods of lower wholesale costs.

Whatever the underlying causes of the return on equity premium we observe, its existence has important implications for capital investment incentives and excess consumer costs. Beyond the direct effect on the capital costs utilities can recover, an age-old concern in the sector has been the way excess regulated returns incentivize utilities to over-invest in capital assets (Averch and Johnson 1962). If regulators set the approved rate of return above a utility's true cost of capital, they will have an incentive to increase the capital base that the rate of return is applied to. This can lead to inefficient over-investment in capital-intensive activities relative to alternatives that do not earn the utility a rate of return premium. The resulting costs from "gold plating" are then passed on to consumers in the form of higher bills. To explore whether this arises in our context we use a regression analysis to identify how a larger gap between a utility's allowed RoE and their actual cost of equity translates into over-investment in capital. We primarily use a within-utility approach (fixed effects and first differences). We also explore, but ultimately rule out, a number of instrumental variables approaches.

In our preferred specification, we find that increasing the RoE gap by one percentage point leads to a 3–4% percent increase in capital assets. We observe similar effects when looking at capital intensity per unit of electricity or gas delivered. In the electric sector the effect appears to be driven by increased distribution grid investment, more than generation or transmission investment. We do not find clear evidence of a corresponding increase in total operating costs. Our findings therefore provide new potential evidence for the Averch–Johnson effect in the utility sector (Vitaliano and Stella 2009; Kuosmanen and Nguyen 2020). This is of particular interest because to date the empirical evidence for this phenomenon has been viewed as quite weak (Joskow and Rose 1989; Joskow 2005).

Combining our measures of the excess equity returns utilities earn with the distortions to capital investment, we estimate the cost to consumers from excess rates of return averaged around $7 billion per year over the past three decades. There is uncertainty around this, and our range of CAPM benchmarks span excess costs averaging $3–11 billion per year, depending on the specification (all in 2019 USD). These excess costs have significant distributional effects, representing a sizable transfer from consumers to investors. This is an important perspective to keep in mind given that much of the discussion on the distributional impacts of energy utility prices has focused on inequities between different types of consumers, rather than between consumers and shareholders (Borenstein, Fowlie, and Sallee 2021; Cahana et al. 2023; Fetzer, Gazze, and Bishop 2024).

Importantly, the large majority of these excess costs are directly due to the return on equity gap. The additional capital from distorted investment incentives, on the other hand, has a relatively modest impact. As such, concerns about an Averch–Johnson distortion to investment incentives, while interesting, are a largely second order effect from perspective of the impact on consumers. Moreover, while excess equity returns may create an incentive to over-invest in capital assets, it does not mean that this will outweigh other inefficiencies that lead utilities to under-invest in capital. For instance, market power (Hausman 2024), regulatory and permitting barriers (Davis, Hausman, and Rose 2023), or a combination of moral hazard and asymmetric information (Lim and Yurukoglu 2018) are all inefficiencies that have been identified as reducing the incentives for utility companies to invest in new grid infrastructure.

More than four fifths of the excess costs we identify come from the electricity sector, which raises an important tension with environmental policy objectives. Ensuring that new capital investment can take place rapidly and in a cost-effective way is seen as critical to enabling the clean energy transition (Hirth and Steckel 2016; Gorman, Mills, and Wiser 2019). Increasingly utilities frame the equity returns they earn within this context. But higher regulated returns can also help keep polluting utility infrastructure operating for longer (Gowrisankaran, Langer, and Reguant 2024). Higher electricity prices hinder efforts to encourage electrification as well (Borenstein and Bushnell 2022). Regulators must therefore balance several competing goals to bear down on costs, encourage electrification, and bring forward new cleaner grid investments at an almost unprecedented scale and speed.

Addressing the inefficiencies in the regulatory process that we highlight remains a key challenge. Ultimately the process of determining utility cost of capital will continue to retain a significant degree of subjective judgment on the part of the regulators. With that in mind we conclude by covering the merits of potential reforms that can guard against certain biases. In particular, we discuss automatic update rules for the cost of equity, bolstering the financial expertise of regulators, and process changes to alter the timing and sequencing of regulatory proceedings.

2 Background

Electricity and natural gas utility companies are typically regulated by government utility commissions, which allow the companies a geographic monopoly and, in exchange, regulate the rates the companies charge. These public utility commissions (PUCs) are state-level regulators in the US. They set consumer rates and other policies to allow the utility companies they regulate to recover their costs. Three quarters of US customers are served by investor-owned utilities (IOUs) that are structured and regulated this way. The remainder are served by municipal or cooperative utilities, which we do not study here. The regulated investor-owned utility model is the dominant industry structure in most advanced economies.

A core activity that PUCs oversee is the rate case process. Here a utility company submits their proposed expenditures over some future time period (e.g. the next 3–5 years). The regulator then determines which expenditures it deems to be prudent and sets consumer rates such that the utility will be able to recover its projected costs. Regulators typically employ a "test year," a single 12-month period in the past or future that will be used as the basis for the rate case analysis. Expenses and costs in this test year, except those with automatic update provisions, are the values used for the entire rate case. A key challenge for the regulator during any rate case proceeding is deciding which costs are reasonable. For some expenses, like fuel purchases or labor expenses, it is relatively easy to calculate and evaluate the companies' costs. For others, like capital, the task is less straightforward.

Utilities own significant amounts of physical capital (power lines, substations, gas pipelines, repair trucks, office buildings, etc.). The types of capital utilities own also varies depending on market and regulatory conditions. Utilities that are vertically integrated might own a large majority of their own generation, the transmission lines, and the distribution infrastructure. Other utilities are "wires only," buying power from independent power producers and transporting it over their lines. Natural gas utilities are typically "pipeline only" – the utility doesn't own the upstream gas well or processing plant. The set of all capital the utility owns is called the rate base (the base of capital that rates are calculated on).

The capital rate base has an opportunity cost of ownership: instead of buying capital, that money could have been invested elsewhere in the economy. Utilities fund their operations through issuing debt and equity, typically about 50%/50%. The weighted average cost of capital is the weighted average of the cost of debt and the cost of equity. During rate case proceedings state public utilities commissions must determine a reasonable level for the cost of capital a utility faces. They are therefore left trying to set a reasonable capital allocation and rate of return that approximates what capital markets would provide if the utility had been a competitive company rather than a regulated monopoly. This rate of return on capital is almost always set as a nominal percentage of the installed capital base. For instance, with an installed capital base worth $10 billion and a rate of return of 8%, the utility is allowed to collect $800 million per year from customers for debt service and to provide a return on equity to shareholders.

The cost of debt financing is easier to estimate than the cost of equity financing. For historical debts, it is sufficient to use the cost of servicing those debts. For forward-looking debt issuance, the cost is estimated based on the quantity and cost of expected new debt. Issues remain for forward looking decisions – e.g. what will bond rates be in the future? – but these are *relatively* less problematic. In our data, we observe both the utilities' proposed rates of return and the final approved value. It's notable that the requested and approved rates are very close for debt, and much farther apart for equity.

The cost of equity financing is more challenging. Theoretically, it's the return shareholders require in order to invest in the utility. The Pennsylvania Public Utility Commission's ratemaking guide notes this difficulty (Cawley and Kennard 2018):

> Regulators have always struggled with the best and most accurate method to use in applying the [*Federal Power Commission v. Hope Natural Gas Company* (1944)] criteria. There are two main conceptual approaches to determine a proper rate of return on common equity: "cost" and "the return necessary to attract capital." It must be stressed, however, that no single one can be considered the only correct method and that a proper return on equity can only be determined by the exercise of regulatory judgment that takes all evidence into consideration.

Unlike debt, where a large fraction of the cost is observable and tied to past issuance, the cost of equity is the ongoing, forward-looking cost of holding shareholders' money. The RoE also conceptually applies to the entire rate base – unlike debt, there's typically no notion of paying a specific RoE for specific stock issues.[1]

Regulators employ a mixture of models and subjective judgment to set the return on equity. A common choice is the capital asset pricing model (CAPM), although other methods such as discounted cash flow are often used too. Utility companies will usually justify their requested values for the return on equity using these methods. Consumer advocate groups often do the same, with differences in the underlying assumptions often leading to substantial divergence in the return on equity that could be deemed appropriate. The regulator is then left to adjudicate these differences and determine a return on equity that is reasonable.

However, it is not obvious that regulator decisions closely follow these standard methods or incorporate important relevant information. Rode and Fischbeck (2019) rule out a number of financial reasons we might see an increasing RoE gap, including utilities' debt/equity ratio, the asset-specific risk (CAPM's β), or the market's overall risk premium. They find that none of these possibilities are supported by the data, and instead highlight a possible behavioral bias where regulators avoid allowing nominal RoE to fall below 10%. There is evidence broader macroeconomic changes often aren't fully included in utility commission ratemaking as well (Salvino 1967; Strunk 2014). Because rates of return are typically set in fixed nominal percentages, rapid changes in inflation can dramatically shift a utility's real return. Typically, regulators also rely on some degree of benchmarking against other US utilities (and often utilities in the same geographic region). There are advantages to this narrow benchmarking, but when market conditions change and everyone is looking at their neighbors, rates will update very slowly.

Another option when costs are likely to vary during the rate case period is to

1. For this paper, we focus on common stocks (utilities issue preferred stocks as well, but those form a very small fraction of utility financing).

have some form of automatic updating. In the 1960s and 70s, state public utilities commissions began adopting automatic fuel price adjustment clauses. Rather than opening a new rate case, utilities used an established formula to change their customer rates when fuel costs changed. The same automatic adjustment has generally not been the norm for capital costs, despite large swings in the nominal cost of capital over the past 50 years. A few jurisdictions have introduced limited automatic updating for the cost of equity, and we discuss those approaches in more detail in section 4.1, where we consider various approaches of estimating the RoE gap.

Lastly, much has been written about modifying the current system of investor-owned utilities, with questions ranging from who pays for fixed grid costs to the role of government ownership or securitization (Farrell 2019; Borenstein, Fowlie, and Sallee 2021). For this paper we assume the current structure of investor-owned utilities, leaving aside other questions of how to set rates across different groups of customers or who owns the capital.

3 Data

To answer our research questions, we use a database of all significant resolved utility rate cases from 1980 to 2022 for every electricity and natural gas utility (Regulatory Research Associates 2024).[2] We merge data from the Energy Information Administration (EIA) on the annual number of customers, quantity of electricity or gas supplied, and sales revenue for the utilities in our sample (Energy Information Administration 2024a, 2024b). Furthermore, we also combine annual financial data from the Federal Energy Regulatory Commission (FERC) for the electric utilities in our sample (Selvans et al. 2024). The EIA data is available from 1990 and the FERC data from 1994. For utilities operating in multiple states we allocate the national

2. The database includes any rate case where a utility either requested a nominal-dollar rate base change of $5 million or had a rate base change of $3 million authorized.

totals from FERC based on their quantity of electricity or gas delivered to end users in each state.

Summary statistics on our sample of rate cases can be seen in Table 1. Our primary variables of interest are the rates of return on equity, the rate base, and various measures of their capital assets or operating costs.[3] As noted earlier, it is striking there is a difference of around a full percentage point between the return on equity that utilities propose and regulators approve. This is in contrast to the other elements of the cost of capital process – such as the return on debt, equity funding share and rate base – where the value of approved by the regulator is generally very close to the value proposed by the utility.[4]

Table 1 also makes clear that we have matched data from FERC and EIA for somewhere between a third and two thirds of our sample, depending on the variable of interest. The FERC data only covers electric utilities, and includes a wealth of detailed information on assets, income, and expenditures broken down into their constituent parts (e.g. transmission, distribution, and generation). Despite the focus on electric utilities, for utilities that deliver both gas and electricity, there is some combined reporting of total assets and operating expenses that allows us to include some gas rate cases in the analysis that relies on this dataset.

Figure 1 plots the approved return on equity from our rate cases over the 40 year time period spanned by our sample. We also plot various risky and risk-free market rates for comparison. A couple of features jump out. The gap between the approved return on equity and other measures of the cost of capital has increased substantially

3. We focus here on proposed and approved regulated rates of return. It is possible that utility's actual rate of return or return on equity might differ from the approved regulated level. In general though, actual returns do tend to track allowed returns quite closely.

4. Given this observed high degree of correspondence for these three variables, we fill in any missing approved values where there is a non-missing proposed value, assuming the approved value is equal to the proposed value for the cost of debt, equity share, and rate base. This procedure allows us to identify values for almost 500 rate cases where the approved return on debt or equity share was missing, and around 300 rate cases where the approved rate base was missing. We then calculate the RoE from the filled values. This procedure allows us to identify values for almost 50 rate cases where the approved return on equity is missing.

Table 1: Summary Statistics

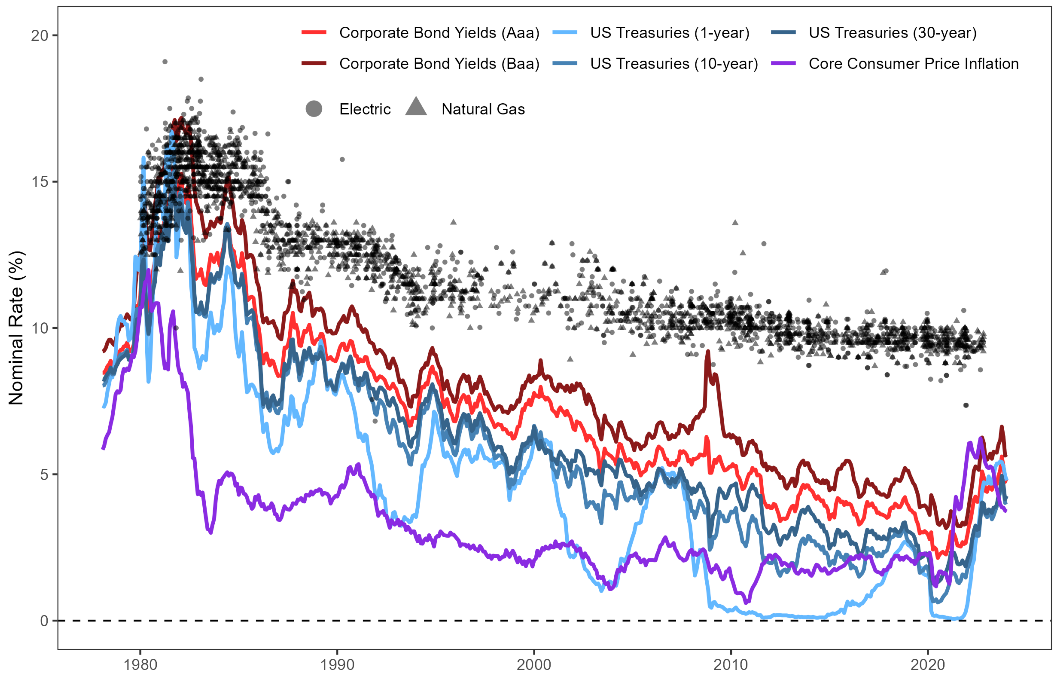
Characteristic	N	Electric	Natural Gas
Rate of Return Proposed (%)	3,589	9.93 (2.00)	9.94 (2.09)
Rate of Return Approved (%)	3,535	9.53 (1.92)	9.40 (1.95)
Return on Equity Proposed (%)	3,614	13.16 (2.70)	12.88 (2.50)
Return on Equity Approved (%)	3,552	12.28 (2.41)	11.87 (2.18)
Return on Debt Proposed (%)	3,581	7.43 (2.16)	7.29 (2.23)
Return on Debt Approved (%)	3,525	7.38 (2.13)	7.18 (2.20)
Equity Funding Proposed (%)	3,606	45 (7)	48 (7)
Equity Funding Approved (%)	3,547	44 (7)	47 (7)
Rate Increase Proposed ($ mn)	3,525	90 (142)	27 (44)
Rate Increase Approved ($ mn)	3,466	44 (92)	14 (27)
Rate Base Proposed ($ mn)	2,288	2,475 (3,705)	732 (1,023)
Rate Base Approved ($ mn)	2,270	2,427 (3,599)	742 (1,019)
Vertically Integrated	3,617	0.87 (0.33)	0.00 (0.00)
Customers (thous)	2,248	674 (932)	512 (792)
Quantity (TWh or Tcf)	2,260	16 (20)	99 (134)
Revenue ($ mn)	2,248	1,389 (1,999)	507 (629)
Operation Expense ($ mn)	1,535	1,280 (1,386)	459 (518)
Total Plant ($ mn)	1,535	8,770 (10,365)	1,787 (2,889)
Elec. Total Plant ($ mn)	1,166	8,256 (9,704)	- (-)
Elec. Dist. Plant ($ mn)	1,166	3,240 (4,337)	- (-)
Elec. Trans. Plant ($ mn)	1,166	1,405 (2,052)	- (-)
Elec. Gen. Plant ($ mn)	1,166	3,109 (4,183)	- (-)
Case Length (yr)	3,261	3.27 (4.01)	3.28 (3.42)

Notes: This table shows the rate case variables in our rate case dataset. Values in the Electric and Natural Gas columns are means, with standard deviations in parenthesis. Approved values are approved in the final determination, and are the values we use in our analysis. Some variables are missing, particularly the approved rate base. The RoE spread in this table is calculated relative to the 10-year Treasury rate.
SOURCE: Regulatory Research Associates (2024), Energy Information Administration (2024a, 2024b), and Selvans et al. (2024), and author calculations.

over time. Consistent with a story where regulators adjust slowly, approved RoE has fallen slightly (in both real and nominal terms), but much less than other costs of capital. This is the key stylized fact that motivates our examination of the return on equity that utilities earn, the implications this may have for their incentives to invest in capital, and the costs they pass on to consumers.

For some components of our analysis we transform our data on rate case events

Figure 1: Return on Equity and Financial Indicators



Notes: These figures show the approved return on equity for investor-owned US electric and natural gas utilities. Each dot represents the resolution of one rate case. Between March 2002 and March 2006 30-year Treasury rates are extrapolated from 1- and 10-year rates (using the predicted values from a regressing the 30-year rate on the 1- and 10-year rates).
Sources: Regulatory Research Associates (2024), Moody's (2021a, 2021b), Board of Governors of the Federal Reserve System (2021a, 2021b, 2021c), and US Bureau of Labor Statistics (2021). An inflation-adjusted version is presented in appendix Figure A.2.

into an unbalanced utility-by-month panel, filling in the rate of return variables in between each rate case. There are some mergers and splits in our sample, but our rate case data provider lists each company by its present-day company name, or the company's last operating name before it ceased to exist. With this limitation in mind, when we construct our panel we do so by (1) not filling data for a company before its first rate case in a state, and (2) dropping companies five years after their last rate case.[5]

Expanding our data in this way allows us to match with annual and monthly data that varies over the course of each rate case. This includes various market rates pulled from FRED, including 1-, 10-, and 30-year Treasury yields, the core consumer price index (CPI), bond yield indexes for corporate bonds rated by Moody's as Aaa or Baa, as well as those rated by S&P as AAA, AA, A, BBB, BB, B, and CCC or lower.[6] Some of these were shown earlier in Figure 1. We also match credit rating, which we take from SNL's *Companies (Classic) Screener* (2021) and WRDS' *Compustat S&P legacy credit ratings* (2019). Utility company credit ratings have changed little over the last 35 years, suggesting there haven't been fundamental shifts in the riskiness of the sector during our sample period.

For much of the analysis we then aggregate our utility-by-month panel back to the original rate case level, averaging our various financial and macroeconomic indicators across each rate case. Here we conduct an initial descriptive regression analysis where we regress the approved return on equity on a range of characteristics of the utility, the regulator, and the case in question.

In Table 2 we see fairly consistent evidence that approved returns on equity tend to be higher for natural gas utilities and for vertically integrated firms. Conversely, approved returns on equity are lower for "wires-only" distribution utilities, and in

5. In contexts where a historical comparison is necessary, but the utility didn't exist in the benchmark year, we use the average of utilities that did exist in that state, weighted by rate base size.

6. Board of Governors of the Federal Reserve System (2021a, 2021b, 2021c), US Bureau of Labor Statistics (2021), Moody's (2021a, 2021b), and Ice Data Indices, LLC (2021b, 2021a, 2021f, 2021d, 2021c, 2021g, 2021e).

Table 2: Relationship Between Approved Rate of Return and Various Utility and Regulator Characteristics

Model:	(1)	(2)	(3)	(4)
Variables				
Case Type = Transmission	-0.0406	0.0300	0.1105	0.3636*
	(0.2875)	(0.3141)	(0.3594)	(0.1818)
Case Type = VerticallyIntegrated	0.4190***	0.4367**	0.5245**	0.2717
	(0.1415)	(0.1795)	(0.2340)	(0.2509)
Decision Type = FullyLitigated	-0.3156***	-0.3168***	-0.2680***	-0.3473***
	(0.0801)	(0.1164)	(0.0669)	(0.0913)
Commissioners = Democrat	-0.1979	-0.0996	-0.2227	-0.3283
	(0.1389)	(0.2096)	(0.1562)	(0.2082)
Commissioners = Elected	0.1066	0.2308	0.6896*	0.8255
	(0.1304)	(0.1872)	(0.4027)	(0.6828)
Commissioners = Tenure (years)	-0.0374***	-0.0458***	-0.0118	-0.0181
	(0.0126)	(0.0161)	(0.0214)	(0.0223)
Service Type = NaturalGas	0.2564**	0.2142*		
	(0.1241)	(0.1237)		
log(Volume)		0.0529*		-0.0523
		(0.0297)		(0.0865)
Fixed-effects				
Year-month	Yes	Yes		
Year-month-Service Type			Yes	Yes
Company-Service Type			Yes	Yes
State-Service Type			Yes	Yes
Fit statistics				
Observations	3,384	2,068	3,384	2,068
R^2	0.86919	0.72462	0.92360	0.89955
Within R^2	0.04828	0.06409	0.03662	0.06403
Dependent variable mean	12.218	10.914	12.218	10.914

Clustered (State) standard-errors in parentheses
Signif. Codes: ***: 0.01, **: 0.05, *: 0.1

Notes: The dependent variable is approved RoE in percentage points. The omitted category for case type is Distribution. The omitted category for decision type is Settled. The omitted category for service type is electricity. The omitted category for political affiliation is Republican or Independent. The omitted category for appointment type is appointed. Columns 1–2 show results with only time fixed effects. Columns 3–4 include a rich set of time, company, state and service type fixed effects. Columns 2 and 4 incorporate data from EIA on the annual volume of gas or electricity provided by each utility, and are therefore limited to cases with a valid match from 1990 onwards.

rate cases where the proceeding was fully litigated. We also find some evidence that the composition of commissioners on the state regulator is correlated with outcomes. For instance, in some specifications a higher percentage of elected (vs appointed) commissioners is correlated with higher returns on equity. Having commissioners with longer tenures or more commissioners that identify as Democrats is correlated with lower returns on equity. Lastly, there is mixed evidence on whether larger utilities, as measured by their volume of energy delivered, tend to receive higher regulated returns on equity.

4 Empirical Findings

This section details our analysis strategy and results. Beginning with 4.1, we present estimates of the return on equity (RoE) gap using a variety of benchmarks. Section 4.2 examines potential mechanisms that can explain why the RoE gap has grown. Lastly, 4.3 estimates the impact of the RoE gap on capital investment and consumer costs.

4.1 Quantifying The Return on Equity Gap

Knowing the size of the RoE premium that companies receive is a challenge, and we take a couple of different approaches. Our primary approach draws on the capital asset pricing model (CAPM). The CAPM is widely used by regulators to support their decisions on utility equity returns. In principle the CAPM provides an objective way to quantify the expected returns for an asset given the risk of that asset and the returns available in the market over-and-above some risk-free rate. In practice its application remains open to a significant degree of subjective interpretation, in large part through the choice of values for its key parameters. As such, CAPM calculations can form part of the negotiation process between regulators and utilities, with the latter having a clear incentive to argue for assumptions that result in the CAPM producing higher estimates of the cost of equity.

We calculate predictions of the cost of equity for each utility using the standard CAPM formula: $RoE = R_f + (\beta \times MRP)$ where R_f is the risk-free rate, MRP is the market risk premium and β is the equity beta for the asset in question – namely each utility in our sample. Our assumed values for each of these parameters are broadly in line with published data (Damodaran 2022a) and values used by regulators at the federal level in the US, as well as those in other advanced economies such as the UK, Australia, and much of Europe (Australian Energy Regulator 2020; Economic Consulting Associates 2020; UK Regulatory Network 2020). The parameter values used by state PUCs in the US tend cause RoEs to fall at the higher end of the range we examine. We calculate the RoE gap by taking the contemporaneous difference between our CAPM estimate of RoE and each utility's allowed RoE. In appendix section B.1, we detail each of the CAPM parameters and the high degrees of freedom available in selecting each. We summarize the range of possible CAPM results in the Figure 2, where we present a central case, a high-RoE case, and a low-RoE case.

Our implementation of the CAPM approach points to persistent evidence of excess returns on equity in the past two decades. Our "central" case uses annual data on the risk-free rate, the β and market risk premium, meaning we are able to produce estimates from 1998 onwards. Here we see an RoE gap that generally lies in the 2–5 percentage point range over the past three decades. An RoE gap of up to 5 percentage points may seem very substantial, implying the regulated RoE is twice the reasonable cost reflective level. However, others have suggested the gap between the allowed RoE and the underlying cost of equity to be of a similar level using information on utility market-to-book ratios (Ellis 2025).

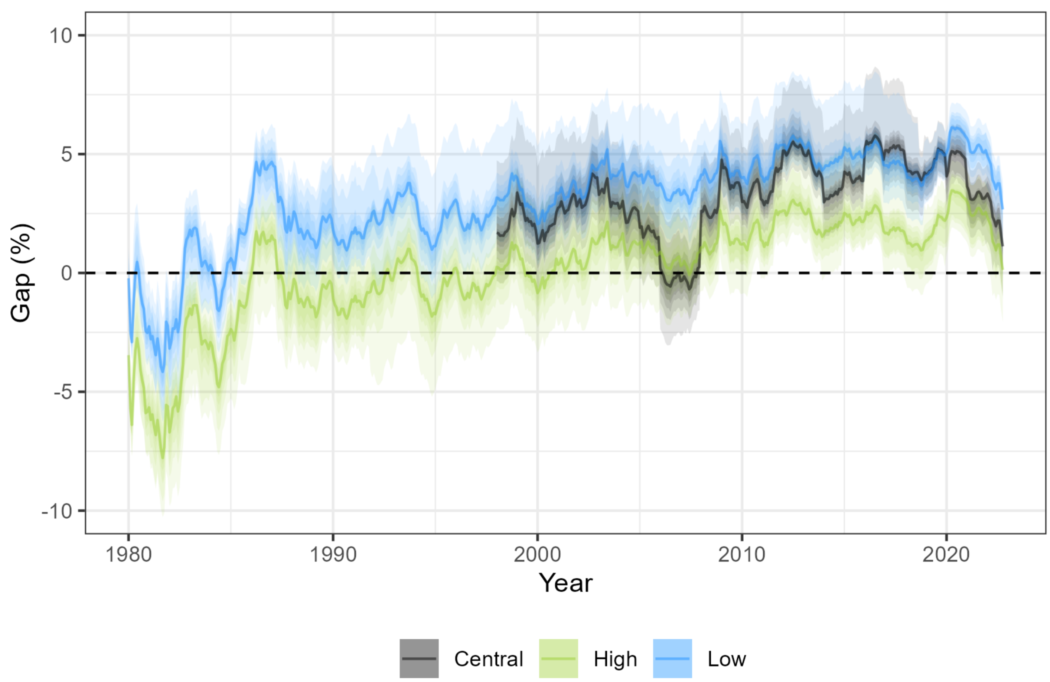
Our "high" version of the CAPM uses annual data on the risk-free rate, and then fixed assumptions for the β and market risk premium that are on the higher end of what has been historically used in the industry. As such, the resulting RoE gap is smaller, ranging from 0.5–2 percentage points over the past three decades. Allowed rates of return are therefore still above the predictions from our "high" CAPM case, although much more closely aligned with the current approach of US state PUCs. Notably though, projecting this same approach back in time appears to suggest that past allowed returns in the 1980s and 1990s were well below the estimated cost of equity. This seems implausible given the large capital expenditures the industry has continued to engage in over the last four decades.

Our "low" version of the CAPM uses annual data on the risk-free rate, and then fixed assumptions for the β and market risk premium that are on the lower end of what has been historically used in the industry. This is particularly true when looking at the practices of US regulators, which appear to utilize higher values than regulators in the UK, Europe, and Australia. As such, the resulting RoE gap is larger, ranging from 3–5 percentage points over the past three decades.

In addition to benchmarking against the CAPM, we also find a similar trend of widening RoE premiums when benchmarking against various measures of debt yields. While relatively simplistic, this kind of comparison draws on the intuition that the required return on equity should not stray too far from the required return on debt over time. Over the past three decades, the spread of RoE relative to 10-year US Treasury bonds or same-rated corporate bonds has increased by around 2–4 percentage points. This replicates the findings of others who have studied this issue by focusing on the spread against US Treasuries (Rode and Fischbeck 2019). Using an automatic update rule that adjusts at *half* the rate of changes in US treasury bond yields produces an RoE gap of 0–1 percentage points.[7] Over the same period, the spread relative to a utility's own approved return on debt has also grown by around 0–2 percentage points. Our debt yield benchmarks are discussed in more detail in appendix section B.2.

7. This draws on the approach taken by the Vermont PUC. Similar automatic update rules for RoE based on a proportion of the change in US Treasury bond yields have also been used in Canada and California.

Figure 2: Return on Equity gap, by different CAPM benchmarks (percentage points)



Notes: Gap percentage figures are a weighted average across utilities, weighted by rate base. Line represents median; shading represents ranges that cover the central 20, 40, 60, 80, and 95% of total investor-owned utility rate base. "Central", "High" and "Low" refer to different Capital Asset Pricing Model benchmarks. See section 4.1 for details of each benchmark calculation.

International comparisons can also be informative. To illustrate this we gather data on allowed returns on equity for gas and electric utilities in the United Kingdom. Here we find that approved RoE in the US has been around 0–4 percentage points higher than approved RoE in UK over the past three decades. A similar premium would likely emerge when comparing to utilities in other countries in Europe which have tended to approve similar rates of return to those we find for the UK. Of course there's no particular reason to think the UK regulator is setting the correct RoE, and there are good reasons to think that US PUCs should not simply adopt UK rates of return – there are many differences between the utility sector and investor environment in the US and UK. Even so, it is notable that other countries are able to attract sufficient investment in their gas and electric utilities while guaranteeing significantly lower regulated returns than are available in the US context. Our benchmark against UK regulatory decisions is discussed in more detail in appendix section B.3.

Overall, our analysis points to a substantial gap between US utilities' approved RoE and various benchmark measures of their underlying capital costs. To explain these large gaps, at least one of three things must be true: (1) historically, utilities were under-compensated for their capital costs, (2) today, utilities are over-compensated for their capital costs, or (3) the structure of utilities' capital costs – and their relationship with other capital markets – has changed dramatically over time. Of these options, (2) is likely the most plausible.

4.2 Potential Mechanisms

The existence of a persistent gap between the return on equity that utilities earn and various measures of the cost of capital they face could have a number of explanations. To try and understand plausible mechanisms we examine three lines of inquiry: (1) whether there are asymmetric adjustments to increases or decreases in underlying capital cost benchmarks; (2) whether utilities strategically time their rate cases to maximize equity returns; and (3) if regulators are motivated by overall prices rather than accurately setting the cost of equity.

4.2.1 Asymmetric Adjustment of Equity Returns

Many studies in several industries have documented that positive shocks to firms' input costs feed through into prices faster than negative shocks (Peltzman 2000; Frey and Manera 2007; Gwin 2009). This pattern has been most extensively studied in the gasoline sector – see Kristoufek and Lunackova (2015) and Perdiguero-García (2013) for reviews of the literature. Building on early work by Bacon (1991) and Borenstein, Cameron, and Gilbert (1997), there are now a wealth of studies examining how positive shocks to crude oil prices lead to faster increases in retail gasoline prices than negative shocks to crude oil prices lead to decreases in retail gasoline prices. This is the so-called "rockets and feathers" phenomenon. A range of explanations for this have been explored, most notably tacit collusion, market power, and the dynamics of consumer search.

In our setting we do observe that a change in some benchmark index (e.g. US Treasuries or corporate bonds) appears to feed through into the regulator-approved return on equity for utilities. This can be seen in Figure 1 where relatively short-run spikes in US Treasuries or corporate bond yields correlate with corresponding spikes in allowed returns on equity. US Treasury bond yields are also an important direct input to CAPM calculations used during the rate case process. Given the sluggish pace at which returns on equity have come down over the longer-term, especially when compared to various benchmark measures of the cost of capital, it therefore seems plausible to think that this pass-through relationship may function differently depending on whether it is a positive or a negative shock. To test this we follow the literature on asymmetric price adjustments and estimate a vector error correction model.

Early studies of asymmetric price adjustments tended to work with single time series of their variables of interest. In our case, we have a panel of rates of return that are divided up across utilities and states. In our main specification we conduct our analysis at the state level, as this allows us to have a balanced panel, while still maintaining the resolution of where decisions are being made: state public utility commissions. To do this, we collapse our company–state–month panel to a state-by-month panel. We do this by averaging the returns on equity from any rate cases decided in a given state in a given month, and then filling forward for any months where there are no new rate cases decided in a state. As a robustness check we also examine versions of the analysis at the original company–state-by-month panel level and find consistent results. See the appendix for further details.

To estimate the vector error correction model we first estimate the long-run relationship between the return on equity for unit i in period t ($RoE_{i,t}$) and a lagged benchmark index of the cost of capital ($Index_{i,t-1}$).[8] We include unit fixed effects, σ_i, in line with other studies of asymmetric adjustment in a panel setting (Asane-Otoo and Dannemann 2022). In our preferred specification our fixed effects are at the state level, and we then estimate an adjustment relationship common to all states.

$$RoE_{i,t} = \phi Index_{i,t-1} + \sigma_i + \varepsilon_{i,t} \tag{1}$$

In the second step we then run a regression of the change in RoE on three sets of covariates: (1) m lags of the past changes in RoE, (2) n lags of the past change in the index, and (3) the residuals from the long-run relationship, $\hat{\varepsilon}_{i,t}$, lagged from the previous period. To examine potential asymmetric adjustment, each of these three sets of covariates is split into positive and negative components to allow the

8. Here, we use 10-year Treasuries as the benchmark. We also conduct unit root tests. Because of the panel setting we use a panel unit root test developed by Maddala and Wu (1999). Our tests fail to reject non-stationarity in levels and reject non-stationarity in first differences.

coefficients for positive changes to differ from the coefficients for negative changes. Once again, we include unit fixed effects, σ_i.

$$\begin{aligned}\Delta RoE_{i,t} = & \sum_{j=1}^{m} \gamma_j^+ \Delta RoE_{i,t-j}^+ + \sum_{j=1}^{m} \gamma_j^- \Delta RoE_{i,t-j}^- \\ & + \sum_{j=1}^{n} \beta_j^+ \Delta Index_{i,t-j}^+ + \sum_{j=1}^{n} \beta_j^- \Delta Index_{i,t-j}^- \\ & + \theta^+ \hat{\varepsilon}_{i,t-1}^+ + \theta^- \hat{\varepsilon}_{i,t-1}^- + \sigma_i + v_{i,t}\end{aligned} \tag{2}$$

To be clear, the asymmetric adjustment process we estimate using this model will mechanically find that in the long run, cost increases or decreases ultimately converge to the same level of pass-through to utility rates of return. In this way, our analysis here cannot directly explain persistent long-run gaps. However, this approach does still provide important insights into short- and medium-term dynamics in the regulatory process that, when repeated over time in multiple rate cases, may help explain the trends highlighted thus far.

We present the results of our analysis of asymmetric adjustment in Figure 3, where we plot the cumulative adjustment function. We simulate the impact on the utility rate of return from a one percentage point shock to the underlying benchmark index. In this case we conduct our analysis at the state level using approved rates of return and nominal 10-year US Treasuries as our benchmark rate. We plot the change in the nominal rate of return on equity over the subsequent six years.[9]

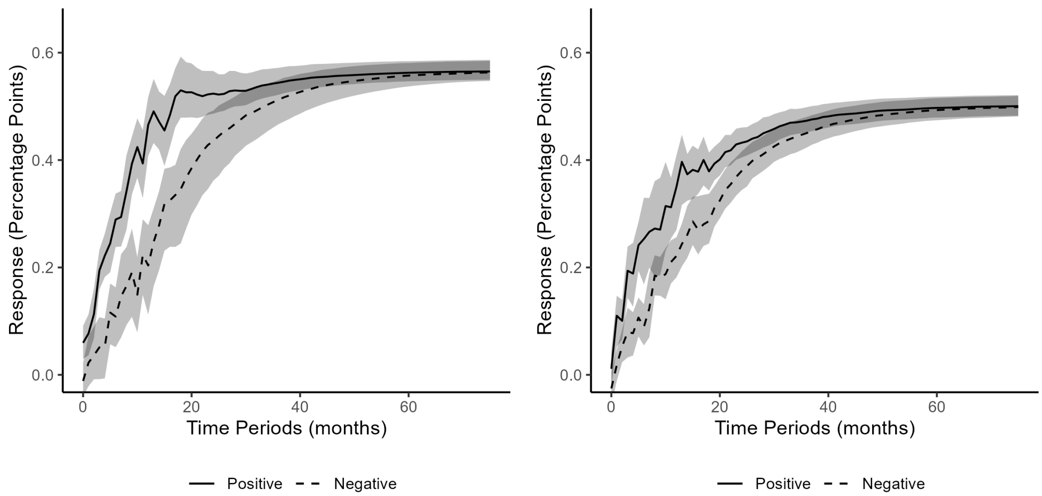
As can be seen in Figure 3, we find evidence of asymmetric adjustment. Rates of return adjust faster to a positive shock (solid line) than to a negative shock (dashed line). In the long run, both converge to a roughly 50% pass-through rate.[10]

9. To do this we rely on the methodology set out by Borenstein, Cameron, and Gilbert (1997) and use bootstrapping to derive 95% confidence intervals. We block bootstrap at the state level, using 1000 draws.

10. It is notable that the coefficient estimates we find for ϕ are generally close to the adjustment factors used in the automatic update rules employed by the Vermont PUC and California PUC (discussed earlier). This suggests these rules appear to largely formalize existing trends.

The degree of asymmetric adjustment appears strongest in the rates of return that utilities propose, but is still present to a notable extent in the rates of return that regulators ultimately approve. The extent of asymmetric adjustment is even more pronounced in the analysis conducted at the utility level which can be found in appendix Figure C.1.

Figure 3: Asymmetric Cumulative Adjustment Path following Shock to Benchmark Index



(a) Proposed Rates *(b) Approved Rates*

NOTES: Lines represents the cumulative adjustment path following a one percentage point change to the benchmark index. Solid line is for an increase in the index and dashed line is for a decrease. 95% confidence intervals are estimated via block bootstrapping on states, with 1000 replications. The plotted results use a benchmark index of 10-year US Treasuries. Analysis across the two panel columns is conducted with either proposed or approved rates of return. See calculation details in section 4.2.1.

4.2.2 Strategic Rate Case Timing

There is not an obvious economic reason why this kind of asymmetric adjustment should arise in this context, which leaves us with explanations focused on the political economy of the regulatory process itself. One mechanism that we explore relates to the timing of when rate cases are initiated and thus how long they last.

In principle many regulators conduct rate cases that are intended to last for a set amount of time. So if a state PUC sticks to a consistent 3 year schedule and a rate case proceeding is resolved at the start of 2012, the prices a utility can charge would be fixed until the start of 2015, and then a new rate case would begin.[11] In practice the timing and duration of rate cases frequently deviates from a regular schedule. Utilities generally have the discretion to initiate a new rate case filing, and providing the regulator agrees to proceed, firms may be able to systematically vary when they initiate new rate cases to their own benefit.

To examine this possibility we regress the RoE gap on the length of the rate case. We include fixed effects at the service type by month-of-sample, service type by company and service type by state level. The variation used for identification is therefore both within-state and within-utility. If there is strategic timing of when utilities initiate rate case we would expect to see a significant positive relationship between the RoE gap and rate case length.

Table 3 shows the results of this analysis. Here we do indeed see evidence of strategic timing. A one year increase in rate case length is associated with a 0.14 percentage point increase in the RoE gap. There are some potential outliers in the sample with particularly short or long gaps between rate cases. These outliers could reflect genuine rate case durations, or if there are rate cases missing from our sample these outliers could be erroneous values. However, limiting the sample to rate cases longer than one year and shorter than ten years reveals a similar-size effect.

11. The actual rate case proceeding (i.e. the deliberations between a new filing being submitted and the decision being resolved) generally lasts around 10 months on average. In this simple example one could imagine the utility filing to begin the process for its next rate case in early 2014. Revenue during the rate case period is still subject to any automatic adjustment clauses that may be in place.

4.2.3 Regulator Prioritizing Total Price Level

One further explanation for the emergence of the RoE gap could be that regulators have different priorities besides setting a capital-cost-reflective rate of return. In particular, there is evidence that regulators may instead be primarily concerned with the overall level of the energy prices that consumers face (Joskow 1974; Hausman 2019). Where this is the case, utilities may be able to have excessive rates of return approved for their capital costs where reductions in other cost drivers enable them to keep total prices low. This would also consistent with evidence that utilities increased transmission and distribution capital investments during periods of lower wholesale costs following the divestiture of their regulated generation assets (Cicala 2025).

To examine this possibility we could regress the RoE gap on the total average gas or electricity prices. Importantly, average total retail prices and the RoE gap are necessarily endogenous – a higher or lower RoE directly determines the capital costs that are then recovered through the overall retail price. As such, it is difficult to draw firm conclusions from examining the relationship with retail prices in this way. However, an alternative approach may be to look at how the RoE gap responds to wholesale prices instead. The capital costs incurred by the utility (e.g. to build and maintain the transmission and distribution grid) are largely distinct from the near-term wholesale cost of gas and electricity. Variations in wholesale costs are also generally passed on to consumers through automatic adjustment clauses. Rising wholesale costs will therefore increase the total prices paid by consumers, but should not necessarily directly affect a utility's cost of equity or capital costs more broadly.

Table 3 shows the results of regressing the RoE gap on wholesale prices.[12] For

12. For gas utilities we take their wholesale gas price to be the state-level citygate price. For electric utilities we do not have spatially disaggregated wholesale electricity price data extending back to the beginning of our sample period. As such we use state-level data on the input fuel price for in-state gas-fired power plants. Gas-fired power plants are often the marginal source of generation, and so

each service type (electric or natural gas), we include fixed effects for each month-of-sample, company, and state. The variation used for identification is therefore both within-state and within-utility. Here we do see a consistent negative relationship. A 1% increase in wholesale prices is associated with a 0.3 percentage point decrease in the RoE gap. This is suggestive evidence that regulators may set stricter rates of return when wholesale costs are relatively high, and more generous rates of return when wholesale costs are relatively low.

Table 3: Relationship Between RoE Gap, Rate Case Length, and Nominal Energy Prices

Model:	(1)	(2)	(3)	(4)
Variables				
Case Length (years)	0.1358***	0.1400***	0.1327***	0.1254***
	(0.0161)	(0.0265)	(0.0168)	(0.0235)
log(Wholesale Price (p/KWh))			-0.3167*	-0.2612*
			(0.1647)	(0.1453)
Fixed-effects				
Service Type-Year-Month	Yes	Yes	Yes	Yes
Service Type-Company	Yes	Yes	Yes	Yes
Service Type-State	Yes	Yes	Yes	Yes
Fit statistics				
Observations	3,203	2,475	2,807	2,206
R^2	0.90	0.91	0.91	0.92
Within R^2	0.19	0.07	0.18	0.07
Dependent variable mean	1.5	1.7	1.8	1.9
$1 <$ Case Length < 10	No	Yes	No	Yes

Clustered (Year & Company) standard-errors in parentheses
Signif. Codes: ***: 0.01, **: 0.05, *: 0.1

NOTES: The table uses the gap between approved RoE and 10-year US Treasuries. The dependent variable is the RoE gap. Case length refers to the number of years a rate case lasts. Columns 1 and 3 include the entire sample. Columns 2 and 4 are limited to rate cases with durations shorter than ten years and longer than one year. Wholesale price refers to the average wholesale electricity or gas price for a given state. For electric utilities this is based on the input fuel price for in-state gas-fired power plants. For gas utilities this is the state-level citygate gas price. Columns 1–2 only have case length as the explanatory variable. Columns 3–4 have case length and wholesale prices as the explanatory variables.

there is a high degree of correlation between wholesale gas and electricity prices. We find similar results if we use input fuel prices for in-state coal-fired power plants instead.

4.3 Impacts on Capital Costs

We turn now to the capital assets that utilities are able to earn a rate of return on: the rate base. To the extent a utility's approved RoE is higher than their actual cost of equity, they will have a too-strong incentive to have capital on their books. The result is inefficient investment in capital and ultimately excess costs for consumers.

4.3.1 Capital Investment Incentives

The scope for rate of return regulation to distort utility capital investment incentives has long been theorized and studied (Averch and Johnson 1962). However, the empirical evidence for the Averch–Johnson effect has been viewed as quite weak, with most studies relying on cross-sectional comparisons, comparing regulated with deregulated states, relying on plant-level (rather than firm-level) data, or being limited by small sample sizes (Joskow and Rose 1989; Joskow 2005). We remedy these shortcomings by using a large dataset of rate cases that are necessarily at the firm-level, and by employing either a fixed effects or first differences approach that allows us to examine within-state and within-utility changes.

To investigate the change in utilities' capital assets and operating expenditures we start by estimating $\hat{\alpha}$ from the following first difference specification, where we regress our measure of capital assets on the estimated RoE gap.

$$\Delta \log(Cap_{i,t}) = \alpha \Delta RoE^{gap}_{i,t} + \lambda_t + \epsilon_{i,t} \tag{3}$$

Here an observation is a utility rate case for utility i in year-of-sample t. The dependent variable, $Cap_{i,t}$, is the value of utility plant recorded in the final year of the rate case. The ideal independent variable would be the gap between the allowed RoE and the utilities' costs of equity. Because the true value is unobservable, we use our measure of the $RoE^{gap}_{i,t}$. Unlike section 4.1, for this analysis we care about differences in the gap between utilities or over time, but do not care about the overall magnitude of the gap. For ease of implementation we focus on our benchmark against US treasuries, but we find very similar results when using our various other CAPM measures. Differences between the measures are largely absorbed by the first differencing and fixed effects.

Our goal is to make causal claims about α, so we are concerned about omitted variables that are correlated with both the estimated RoE gap and the change in rate base. Our regressions therefore include time fixed effects, λ_t, at the month-of-sample level. Our first differencing takes place at the service type, utility company, and state level. Fixed effects specifications that include these variables as unit fixed effects, σ_i, can be found in appendix table D.1. The identifying variation in our preferred specification is the difference in the RoE gap within the range of rate case decisions for a given utility and a given state, relative to the annual average across all utilities. We did also consider and rule out a number of instrumental variables strategies. These are documented in the appendix.

The first differencing and fixed effects handle many of the most critical threats to identification, such as macroeconomic trends, technology-driven shifts in electrical consumption, or static differences in state PUC and utility company characteristics. We also capture the fact that utilities that operate in multiple states still file rate cases with each state's utility regulator. Of course, potential threats to causal identification remain. One possibility is omitted variables – perhaps regulators in some states change their posture toward utilities over time, in a way that is correlated with both the RoE and the change in their capital assets and rate base. Another possibility is reverse causation – perhaps the regulator pushes for more capital investment (e.g. aiming to increase local employment) and the utility, facing increasing marginal costs of capital, needs a higher RoE.

Table 4 shows our results from regressing utility capital assets on the RoE gap. We find that a 1 percentage point increase in the approved RoE gap leads to a ~4% increase in capital assets (column 1). Because the return on equity is earned on the capital that makes up the rate base, utilities' incentive to increase their capital assets should differ from their incentive to increase their operating expenditures. When looking at the effect on operating expenses, we find no significant positive effect (column 2). This is consistent with theoretical predictions and provides new potential evidence for the Averch–Johnson effect, with a positive RoE gap leading utilities to shift toward more capital-intensive activities.

Table 4: Relationship Between Approved Rate of Return and Utility Capital, Opex, and Rate Base

Model:	Capital (1)	Op Ex (2)	Rate Base (3)
Variables			
RoE gap (%)	0.0340**	-0.0149	0.0262***
	(0.0123)	(0.0116)	(0.0092)
Fit statistics			
Observations	1,298	1,300	1,884
R^2	0.38	0.51	0.25
Within R^2	0.03	0.003	0.007
Dep. var. mean	8,253.6	1,180.4	1,999.8

Clustered (Year & Company) standard-errors in parentheses
Signif. Codes: ***: 0.01, **: 0.05, *: 0.1

Notes: The table uses the gap between approved RoE and 10-year US Treasuries. Dependent variables are logs of nominal USD. This table only includes utilities that report through FERC Form 1 and so is limited to electric utilities, or combined electric and natural gas utilities. Column 1 refers to the total capital (utility plant) at the end of the rate case. Column 2 refers to the total opex (operating expenses) at the end of the rate case. Column 3 refers to the total rate base at the end of the rate case (i.e. the value approved in the subsequent rate case).

Studying the direct impact on the rate base is less straightforward because the rate base we observe for a given rate case is usually decided simultaneously with the return on equity. We therefore examine the impact of the RoE gap on the rate base approved in the *subsequent* rate case. Here we find a significant positive effect, with a 1 percentage point increase in the approved RoE gap leading to a ~3% increase in the approved rate base (column 3). This is similar to the effect we find for capital assets (column 1). In fact, there is a strong correspondence between our measure of capital assets (from the FERC data) and our data on the rate base (from the original rate case data). A 1% increase in capital assets is associated with a 0.4–0.7% increase in the rate base, depending on the choice of fixed effects. As such, we take our FERC-reported capital asset results as providing a good guide to the impact of the RoE gap on capital ownership.

In addition to looking at total capital assets and operating expenditures, we are also able to look in more detail for electric utilities at what is driving the observed effects. These results can be found in Table 5. Here we see the increase in capital assets appears to be most clearly driven by distribution grid investments. This makes sense given these make up the largest proportion of the assets that are likely to be subject to rate of return regulation. For transmission and generation plant we limit our sample to rate cases where the utility is regulated as a vertically integrated entity. This reduces the chance we are capturing merchant generation assets or transmission infrastructure regulated at the federal level. Here we do also see positive effects but they are less precisely estimated and so are not statistically significant. Lastly, the other remaining capital assets (e.g. office buildings, maintenance trucks, IT equipment) also see a positive significant effect, although these make up a much smaller proportion of total assets.

Consistent with the prior results, we also find no clear increase in total operating costs. This is primarily due to there being no change in generation costs as these make up the vast majority of operational costs.[13] For some of the smaller components of operating costs, such as distribution and other operating costs, we do see some evidence of an increase in response to the RoE gap. These additional operating costs could be a byproduct of utilities increasing their capital investments, which may in

13. In fact the negative coefficient we observe is consistent with the earlier analysis of the relationship between the RoE gap and wholesale prices.

Table 5: Relationship Between Approved Rate of Return and Electric Utility Capital and Opex by Expenditure Type

Model:	Total (1)	Dist (2)	Trans (3)	Gen (4)	Other (5)
Variables					
RoE gap (%)	0.0362**	0.0309***	0.0347	0.1095	0.0327*
	(0.0152)	(0.0100)	(0.0338)	(0.0657)	(0.0177)
Fit statistics					
Observations	978	981	673	738	969
R^2	0.44	0.56	0.34	0.46	0.41
Within R^2	0.03	0.04	0.009	0.03	0.01
Dep. var. mean	9,580.4	3,812.8	1,894.6	4,614.4	573.3

Clustered (Year & Company) standard-errors in parentheses
Signif. Codes: ***: 0.01, **: 0.05, *: 0.1

(a) Capital

Model:	Total (1)	Dist (2)	Trans (3)	Gen (4)	Other (5)
Variables					
RoE gap (%)	-0.0085	0.0466***	0.0356	-0.0146	0.0237*
	(0.0138)	(0.0162)	(0.0401)	(0.0198)	(0.0118)
Fit statistics					
Observations	905	905	683	685	905
R^2	0.58	0.37	0.47	0.71	0.40
Within R^2	0.002	0.02	0.005	0.004	0.01
Dep. var. mean	1,611.4	120.1	100.2	1,227.1	291.5

Clustered (Year & Company) standard-errors in parentheses
Signif. Codes: ***: 0.01, **: 0.05, *: 0.1

(b) Operating Expenses

NOTES: The table uses the gap between approved RoE and 10-year US Treasuries. Dependent variables are logs of nominal USD. This table only includes utilities that report through FERC Form 1 and so is limited to electric utilities. Columns 1–5 in the top panel refer to capital assets (utility plant) broken down by type into total, distribution, transmission, generation, and other. Columns 1–5 in the bottom panel refer to operating expenses broken down by type into total, distribution, transmission, generation, and other. To ensure we focus on non-merchant capital assets regulated by PUCs, columns 3–4 limit the sample to utilities where the rate case is classed as vertically integrated. The specification used is the same as is used in Table 4.

turn come with associated operations and maintenance costs. In aggregate these non-generation operating costs are relatively small in scale.

Lastly, for all our various results we also examine versions that divide the outcome variable by the kWh of energy delivered. These measure the response in intensity terms – how the RoE gap affects capital ownership and operating costs per kWh delivered. Throughout we find similar results to those already set out here, and the full details can be found in the appendix. [14]

4.3.2 Excess Consumer Costs

Utilities engaging in excess capital investment and earning inflated equity returns has implications for consumer costs. Here we take into account our findings on the scale of the RoE premium utilities may be earning, and the way that premium distorts their capital investment decisions. As a caveat, we note that utilities can increase their capital holdings in two distinct ways. One option is to reshuffle capital ownership, either between subsidiaries or across firms, so that the utility ends up with more capital on its books, but the total amount of capital is unchanged. The second option is to actually buy and own more capital, increasing the total amount of capital that exists in the state's utility sector. We do not differentiate between these two cases. Because we don't differentiate, we consider excess payments by utility customers, but we remain agnostic about the socially optimal level of capital investment.

Across our various CAPM measures and using the existing rate base we find excess costs over the past three decades averaged \$2.8–9.1 billion per year, with a central estimate of \$6.2 billion per year.[15] The economic welfare loss is likely smaller than these excess cost measures – the excess capital provides non-zero benefit,

14. Appendix tables E.1 and E.2, correspond to our main tables 4 and 5. Appendix tables E.3 and E.4 present the per-kWh version of appendix tables D.1 and D.2.

15. We focus here on the last three decades to ensure comparability between benchmarks with differing levels of completeness in earlier years.

and the ultimate recipients of utility revenues place some value on the additional income.[16]

Accounting for the way the RoE gap can affect capital ownership increases our estimate of the excess cost to consumers using our CAPM measures to $3.1–10.6 billion per year, with a central estimate of $7.2 billion per year.[17] More than four fifths of these costs come from the electricity sector. A detailed breakdown of these costs across our different benchmarks can be found in Appendix G.

5 Conclusion

The utility sector is a capital-intensive industry, and a corporate utility structure requires investors in the industry be fairly compensated for the opportunity cost of their investments. Getting this rate of return correct, particularly the return on equity, is challenging, but is a task of first-order importance for regulators. In making their determinations, regulators must balance their mandate to keep costs down with the need to bring forward significant new capital investment to modernize an aging grid and deliver on the clean energy transition.

Our analysis shows that the return on equity that utilities are allowed to earn has changed dramatically relative to various financial benchmarks in the economy. We estimate that the current average approved return on equity is markedly higher than various benchmarks and historical relationships would suggest. These results are necessarily uncertain, and depending on our chosen benchmark the cost of equity premium utilities receive ranges from around half a percentage point to greater than four percentage points. Put another way, even our highest benchmarks come in below the allowed rates of return on equity that regulators set today.

16. The RoE gap will ultimately affect utility rates, including the costs of buying electricity, but the ultimate impact on consumption decisions will depend on each utility's rate structure. Analyzing these is outside the scope of this paper.

17. For comparison, total 2019 electricity sales by investor owned utilities were $204 billion, on 1.89 PWh of electricity (US Energy Information Administration 2020).

We link this divergence between the return on equity regulators approve and the cost of equity utilities face to inefficiencies and asymmetries in the rate case process. In a novel analysis, we find evidence that increases to benchmark measures of the cost of capital lead to faster rises in utility returns on equity than is the case for decreases. This is the so-called "rockets and feathers" phenomenon and could be indicative of regulators being more responsive to pressures from the utilities they regulate than from consumers' demands to keep prices down. We provide evidence this is at least partially driven by utility companies strategically varying the timing and duration of rate cases. We also highlight other potential mechanisms, including regulators being responsive to the overall level of prices rather than changes in underlying capital costs.

We then turned to the implications for capital investment incentives. Here we do indeed find new evidence that utilities alter their capital investments in response to the return on equity premium they are likely to earn on those assets. We estimate that an additional percentage point in the RoE gap leads to a ~3–4% increase in utility capital assets. For electric utilities this appears to be led by increased investments in their distribution assets. We find no clear impact of the RoE gap on utilities' operating expenditures. These findings are new potential evidence of the Averch–Johnson effect that has long been discussed in this industry.

Combining our preferred benchmark for the gap with our estimated impact on capital investment puts the excess rates collected from consumers at around $7 billion per year. The impact on overall welfare remains unclear – any excess capital investment presumably has some non-zero value. However, we take our measure of excess costs as providing insight into the degree to which the existing regulatory process may be leading to higher prices that lead to a significant transfer from consumers to shareholders.

If utilities are earning excess returns on equity, a key challenge is to identify what changes to the ratemaking process may help remedy this. Regulators have taken numerous steps over the past few decades to improve the way costs are passed through into rates. For instance, explicit benchmarking and automatic update rules were introduced for fuel costs decades ago. It seems plausible that they could also be used to help equity costs adjust more quickly to changing market conditions, and do so in ways that are less prone to the subjective negotiations and political considerations of the ratemaking process.

However, the cost of equity is unlikely to perfectly track any single benchmark in the same way as the cost of fuel. Also the automatic update rules for equity returns that have already been put in place by some PUCs have done little to prevent the trends we highlight.[18] As such, a significant degree of regulatory judgment is inevitable in this area.

A clear first step for improving the decisions regulators make over the cost of equity is to avoid some of the arbitrary "rules of thumb" that have been employed to date – see for instance, the surprisingly frequent practice of rounding the RoE to whole numbers documented in appendix figure F.1. Bolstering the financial expertise of regulators is a promising remedy here.[19] Seemingly objective methods like the capital asset pricing model cannot provide a definitive answer on the cost of equity. As we have documented, a range of plausible input assumptions can lead to widely divergent estimates of the cost of equity. When incorporating evidence from these methods regulators need to have the expertise to understand their limitations and push back on the assumptions utilities put forward when using them.

Given our findings on the ways utility companies may systematically alter the timing and duration of rate cases, public utilities commissions could remedy this by committing to a fixed rate case review schedule. Regulators need to be mindful that

18. For instance, regulators at the California PUC feel that the rule, called the cost of capital mechanism (CCM), performed poorly. "The backward looking characteristic of CCM might have contributed to failure of ROEs in California to adjust to changes in financial environment after the financial crisis. The stickiness of ROE in California during this period, in the face of declining trend in nationwide average, calls for reassessment of CCM." (Ghadessi and Zafar 2017)

19. Azgad-Tromer and Talley (2017) found that providing finance training to regulatory staff had a moderate effect on moving rates of return closer to standard asset pricing predictions.

when utility companies file for new rate cases (or request extensions to an existing one), they have clear incentives to make these decisions in an asymmetric manner that increases equity returns. Regulators should also ensure that when setting the rate of return their decisions are not unduly influenced by favorable reductions in other costs that are largely outside of a utility's control (e.g. wholesale costs).

Lastly, process reforms may also be beneficial. In most rate case proceedings, utilities submit their planned expenditures and then regulators decide whether they are prudent. This relies on the notion that utilities are best placed to forecast their detailed needs for labor, materials, and, equipment (e.g. numbers of new transformers needed and where). However, it is less clear that utilities should take the lead when it comes to the cost of equity, especially given that this is so dependent on wider market forces, the performance of peer companies, and general investor sentiment. For this component of utility costs, the regulator could conduct its own independent internal analysis of the cost of equity first, and then consult on their proposals. In this way it is the regulator that is anchoring the starting point of the discussion, not the utility.

Our findings have important implications beyond just the additional cost they place on consumers. From a distributional standpoint, higher rates create a transfer from ratepayers to utility stockholders. A high rate of return for *regulated* utilities may also lead to a reshuffling of which assets are owned by regulated versus non-regulated firms. Finally, efficiently pricing energy has important implications for environmental policy, particularly with regard to encouraging electrification which is a key component of efforts to tackle climate change. These are all fruitful avenues for further research.

References

Asane-Otoo, Emmanuel, and Bernhard C. Dannemann. 2022. "Rockets and Feathers Revisited: Asymmetric Retail Gasoline Pricing in the Era of Market Transparency." *The Energy Journal* 43 (6): 103–122. https://doi.org/10.5547/01956574.43.6.easa. eprint: https://doi.org/10.5547/01956574.43.6.easa. https://doi.org/10.5547/01956574.43.6.easa.

Aspuru, Pello. 2024. "Delaying the Coal Twilight: Local Mines, Regulators, and the Energy Transition." *Job Market Paper.*

Averch, Harvey, and Leland L Johnson. 1962. "Behavior of the firm under regulatory constraint." *The American Economic Review* 52 (5): 1052–1069.

Azgad-Tromer, Shlomit, and Eric L. Talley. 2017. "The Utility of Finance." *Columbia University School of Law Working Paper,* https://doi.org/http://dx.doi.org/10.2139/ssrn.2994314. https://ssrn.com/abstract=2994314.

Bacon, Robert W. 1991. "Rockets and feathers: the asymmetric speed of adjustment of UK retail gasoline prices to cost changes." *Energy Economics* 13 (3): 211–218. https://doi.org/https://doi.org/10.1016/0140-9883(91)90022-R. https://www.sciencedirect.com/science/article/pii/014098839190022R.

Ball, Laurence, and N. Gregory Mankiw. 1994. "Asymmetric Price Adjustment and Economic Fluctuations." *The Economic Journal* 104, no. 423 (March): 247–261. https://doi.org/10.2307/2234746. eprint: https://academic.oup.com/ej/article-pdf/104/423/247/27039817/ej0247.pdf. https://doi.org/10.2307/2234746.

Borenstein, Severin, and James Bushnell. 2022. "Do Two Electricity Pricing Wrongs Make a Right? Cost Recovery, Externalities, and Efficiency." Forthcoming, *American Economic Journal: Economic Policy,* https://doi.org/10.1257/pol.20190758.

Borenstein, Severin, A. Colin Cameron, and Richard Gilbert. 1997. "Do Gasoline Prices Respond Asymmetrically to Crude Oil Price Changes?*." *The Quarterly Journal of Economics* 112, no. 1 (February): 305–339. https://doi.org/10.1162/003355397555118. eprint: https://academic.oup.com/qje/article-pdf/112/1/305/5291684/112-1-305.pdf. https://doi.org/10.1162/003355397555118.

Borenstein, Severin, Meredith Fowlie, and James Sallee. 2021. *Designing Electricity Rates for An Equitable Energy Transition.* Technical report 314. February. https://haas.berkeley.edu/wp-content/uploads/WP314.pdf.

Cahana, Michael, Natalia Fabra, Mar Reguant, and Jingyuan Wang. 2023. "The Distributional Impacts of Real-Time Pricing." *CEPR Discussion Paper,* no. 17200, https://cepr.org/publications/dp17200.

Cawley, James H, and Norman J Kennard. 2018. *A Guide to Utility Ratemaking.* Technical report. Pennsylvania Public Utility Commission. https://www.puc.pa.gov/General/publications_reports/pdf/Ratemaking_Guide2018.pdf.

Cicala, Steve. 2025. "Restructuring the Rate Base." *AEA Papers and Proceedings* 115 (May).

Dal Bó, Ernesto. 2006. "Regulatory Capture: A Review." *Oxford Review of Economic Policy* 22, no. 2 (July 1, 2006): 203–225. Accessed August 13, 2022. https://doi.org/10.1093/oxrep/grj013.

Damodaran, Aswath. 2023. "Equity Risk Premiums (ERP): Determinants, Estimation and Implications - The 2023 Edition." *SSRN Working Paper* (March 23, 2023). https://doi.org/http://dx.doi.org/10.2139/ssrn.4398884.

Davis, Lucas W., Catherine Hausman, and Nancy L. Rose. 2023. "Transmission Impossible? Prospects for Decarbonizing the US Grid." *Journal of Economic Perspectives* 37, no. 4 (December): 155–80. https://doi.org/10.1257/jep.37.4.155. https://www.aeaweb.org/articles?id=10.1257/jep.37.4.155.

EIA. 2018a. *Major utilities continue to increase spending on U.S. electric distribution systems.* Report, Today In Energy. Energy Information Administration. https://www.eia.gov/todayinenergy/detail.php?id=36675.

———. 2018b. *Utilities continue to increase spending on transmission infrastructure.* Report, Today In Energy. Energy Information Administration. https://www.eia.gov/todayinenergy/detail.php?id=34892.

Ellis, Mark. 2025. *Rate of Return Equals Cost of Capital: A Simple, Fair Formula to Stop Investor-Owned Utilities From Overcharging the Public.* Report, American Economic Liberties Project Report. American Economic Liberties Project. https://www.economicliberties.us/our-work/rate-of-return/#.

Farrell, John. 2019. "Power Plant Securitization: Coming to a State Capitol Near You." *Institute for Local Self-Reliance* (May 13, 2019). https://ilsr.org/power-plant-securitization-coming-to-a-state-capitol-near-you/.

Fetzer, Thiemo, Ludovica Gazze, and Menna Bishop. 2024. "Distributional and climate implications of policy responses to energy price shocks." *Economic Policy* (July): eiae038. https://doi.org/10.1093/epolic/eiae038. eprint: https://academic.oup.com/economicpolicy/advance-article-pdf/doi/10.1093/epolic/eiae038/59036272/eiae038.pdf. https://doi.org/10.1093/epolic/eiae038.

Frey, Giliola, and Matteo Manera. 2007. "ECONOMETRIC MODELS OF ASYMMETRIC PRICE TRANSMISSION." *Journal of Economic Surveys* 21 (2): 349–415. https://doi.org/https://doi.org/10.1111/j.1467-6419.2007.00507.x. eprint: https://onlinelibrary.wiley.com/doi/pdf/10.1111/j.1467-6419.2007.00507.x. https://onlinelibrary.wiley.com/doi/abs/10.1111/j.1467-6419.2007.00507.x.

Ghadessi, Maryam, and Marzia Zafar. 2017. *An Introduction to Utility Cost of Capital.* Technical report. April 18, 2017. https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/Organization/Divisions/Policy_and_Planning/PPD_Work/PPD_Work_Products_(2014_forward)/PPD-An-Introduction-to-Utility-Cost-of-Capital.pdf.

Gorman, Will, Andrew Mills, and Ryan Wiser. 2019. "Improving estimates of transmission capital costs for utility-scale wind and solar projects to inform renewable energy policy." *Energy Policy* 135:110994. https://doi.org/https://doi.org/10.1016/j.enpol.2019.110994. https://www.sciencedirect.com/science/article/pii/S0301421519305816.

Gowrisankaran, Gautam, Ashley Langer, and Mar Reguant. 2024. *Energy Transitions in Regulated Markets.* Working Paper, Working Paper Series 32088. National Bureau of Economic Research, January. https://doi.org/10.3386/w32088. http://www.nber.org/papers/w32088.

Green Mountain Power: Multi-Year Regulation Plan 2020–2022. 2020. Technical report. September 3, 2020. Accessed March 17, 2021. https://puc.vermont.gov/sites/psbnew/files/doc_library/green-mountain-power-multi-year-regulation-plan.pdf.

Gwin, Carl R. 2009. "Asymmetric Price Adjustment: Cross-Industry Evidence." *Southern Economic Journal* 76 (1): 249–265. https://doi.org/https://doi.org/10.4284/sej.2009.76.1.249. eprint: https://onlinelibrary.wiley.com/doi/pdf/10.4284/sej.2009.76.1.249. https://onlinelibrary.wiley.com/doi/abs/10.4284/sej.2009.76.1.249.

Hausman, Catherine. 2019. "Shock Value: Bill Smoothing and Energy Price Pass-Through." *The Journal of Industrial Economics* 67, no. 2 (December 4, 2019): 242–278. https://doi.org/10.1111/joie.12200.

———. 2024. *Power Flows: Transmission Lines, Allocative Efficiency, and Corporate Profits.* Working Paper, Working Paper Series 32091. National Bureau of Economic Research, January. https://doi.org/10.3386/w32091. http://www.nber.org/papers/w32091.

Heern, Jared. 2023. "Who's controlling our energy future? Industry and environmental representation on United States public utility commissions." *Energy Research & Social Science* 101:103091. https://doi.org/https://doi.org/10.1016/j.erss.2023.103091. https://www.sciencedirect.com/science/article/pii/S2214629623001512.

Hirth, Lion, and Jan Christoph Steckel. 2016. "The role of capital costs in decarbonizing the electricity sector." *Environmental Research Letters* 11, no. 11 (November): 114010. https://doi.org/10.1088/1748-9326/11/11/114010.

IEA. 2023. *Electricity Grids and Secure Energy Transitions.* Technical report. January 11, 2023. https://www.iea.org/reports/electricity-grids-and-secure-energy-transitions.

Joskow, Paul L. 1972. "The Determination of the Allowed Rate of Return in a Formal Regulatory Hearing." *The Bell Journal of Economics and Management Science* 3 (2): 632–644. https://doi.org/10.2307/3003042.

———. 1974. "Inflation and Environmental Concern: Structural Change in the Process of Public Utility Price Regulation." *The Journal of Law and Economics* 17, no. 2 (October): 291–327. https://doi.org/10.1086/466794.

———. 2005. "Regulation and Deregulation after 25 Years: Lessons Learned for Research in Industrial Organization." *Review of Industrial Organization* 26 (2): 169–193. Accessed September 10, 2024. http://www.jstor.org/stable/41799229.

Joskow, Paul L., Douglas R. Bohi, and Frank M. Gollop. 1989. "Regulatory Failure, Regulatory Reform, and Structural Change in the Electrical Power Industry." *Brookings Papers on Economic Activity. Microeconomics* 1989:125–208. Accessed August 13, 2022. https://doi.org/10.2307/2534721.

Joskow, Paul L., and Nancy L. Rose. 1989. "Chapter 25 The effects of economic regulation," 2:1449–1506. Handbook of Industrial Organization. Elsevier. https://doi.org/https://doi.org/10.1016/S1573-448X(89)02013-3. https://www.sciencedirect.com/science/article/pii/S1573448X89020133.

Kristoufek, Ladislav, and Petra Lunackova. 2015. "Rockets and feathers meet Joseph: Reinvestigating the oil–gasoline asymmetry on the international markets." *Energy Economics* 49:1–8. https://doi.org/https://doi.org/10.1016/j.eneco.2015.01.013. https://www.sciencedirect.com/science/article/pii/S0140988315000274.

Kuosmanen, Timo, and Tuan Nguyen. 2020. "Capital bias in the Nordic revenue cap regulation: Averch-Johnson critique revisited." *Energy Policy* 139:111355. https://doi.org/https://doi.org/10.1016/j.enpol.2020.111355. https://www.sciencedirect.com/science/article/pii/S0301421520301129.

Lim, Claire S. H., and Ali Yurukoglu. 2018. "Dynamic Natural Monopoly Regulation: Time Inconsistency, Moral Hazard, and Political Environments." *Journal of Political Economy* 126 (1): 263–312. https://doi.org/10.1086/695474. eprint: https://doi.org/10.1086/695474. https://doi.org/10.1086/695474.

Maddala, G. S., and Shaowen Wu. 1999. "A Comparative Study of Unit Root Tests with Panel Data and a New Simple Test." *Oxford Bulletin of Economics and Statistics* 61 (S1): 631–652. https://doi.org/https://doi.org/10.1111/1468-0084.0610s1631. eprint: https://onlinelibrary.wiley.com/doi/pdf/10.1111/1468-0084.0610s1631. https://onlinelibrary.wiley.com/doi/abs/10.1111/1468-0084.0610s1631.

Michelfelder, Richard A., and Panayiotis Theodossiou. 2013. "Public Utility Beta Adjustment and Biased Costs of Capital in Public Utility Rate Proceedings." *The Electricity Journal* 26 (9): 60–68. https://doi.org/https://doi.org/10.1016/j.tej.2013.09.017. https://www.sciencedirect.com/science/article/pii/S1040619013002340.

Peltzman, Sam. 2000. "Prices rise faster than they fall." *Journal of Political Economy* 108 (3): 466–502. https://doi.org/10.1086/262126.

Perdiguero-García, Jordi. 2013. "Symmetric or asymmetric oil prices? A meta-analysis approach." *Energy Policy* 57:389–397. https://doi.org/https://doi.org/10.1016/j.enpol.2013.02.008. https://www.sciencedirect.com/science/article/pii/S0301421513000931.

Rode, David C., and Paul S. Fischbeck. 2019. "Regulated equity returns: A puzzle." *Energy Policy* 133 (October): 110891. https://doi.org/10.1016/j.enpol.2019.110891.

Salvino, S. M. 1967. "Rate of Return Dilemma of Public Utilities under Rising Cost of Money Conditions." *Financial Analysts Journal* 23 (6): 45–49. http://www.jstor.org/stable/4470243.

Strunk, Kurt G. 2014. *The Decoupling of Treasury Yields and the Cost of Equity for Public Utilities.* Technical report. June 13, 2014. https://www.nera.com/content/dam/nera/publications/archive2/PUB_Equity_Risk_Premium_Utilities_0614(1).pdf.

Vitaliano, Donald F., and Gregory P. Stella. 2009. "A Frontier Approach to Testing the Averch–Johnson Hypothesis." *International Journal of the Economics of Business* 16, no. 3 (October 30, 2009): 347–363. https://doi.org/10.1080/13571510903227031.

Online Supplemental Appendix

A Detail on Data and Summary Statistics

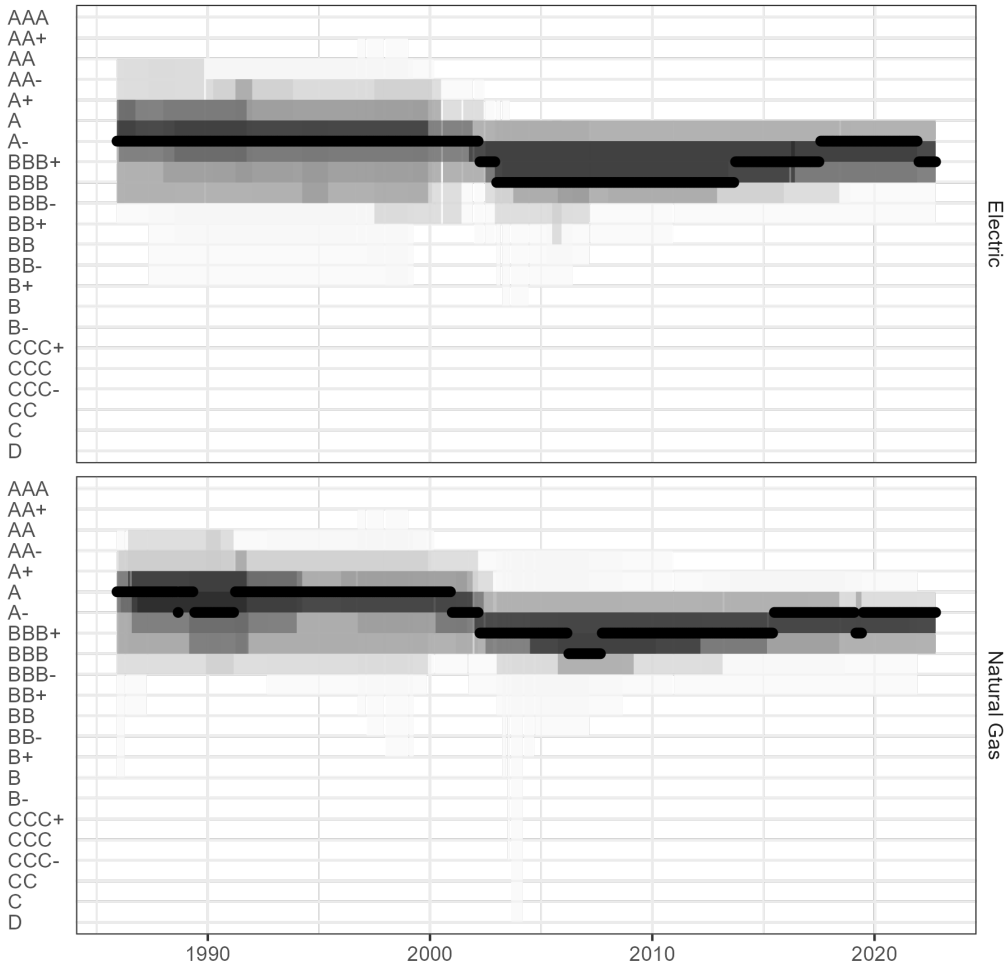
A.1 Credit Ratings Match

When matching credit ratings, we use *Companies (Classic) Screener* (2021) and *Compustat S&P legacy credit ratings* (2019). Most investor-owned utilities are subsidiaries of publicly traded firms. We use the former data to match as specifically as possible, first same-firm, then parent-firm, then same-ticker. We match the latter data by ticker only. Then, for a relatively small number of firms, we fill forward.[1] Between these two sources, we have ratings data available from December 1985 onward. Approximately 80% of our utility–month observations are matched to a rating. Match quality improves over time: approximately 89% of observations after 2000 are matched.

These credit ratings have changed little over 35 years. In Figure A.1 we plot the median (in black) and various percentile bands (in shades of grey) of the credit rating for utilities active in each month. We note that the median credit rating has seen modest movements up and down over the past decades. The distribution of ratings is somewhat more compressed in 2021 than in the 1990s. While credit ratings are imperfect, we would expect rating agencies to be aware of large changes in riskiness. For utility risk to drive up the firms' cost of equity but not affect credit ratings, one would need to tell a very unusual story about information transmission or the credit rating process. Instead, the median credit rating for electricity utilities is A−, as it was for all of the 1990s. The median credit rating for natural gas utilities is also A−, down from a historical value of A.

1. When multiple different ratings are available, e.g. different ratings for subsidiaries trading under the same ticker, we take the median rating. We round down (to the lower rating) in the case of an even number of ratings.

Figure A.1: Utility Credit Ratings, 1985-2023



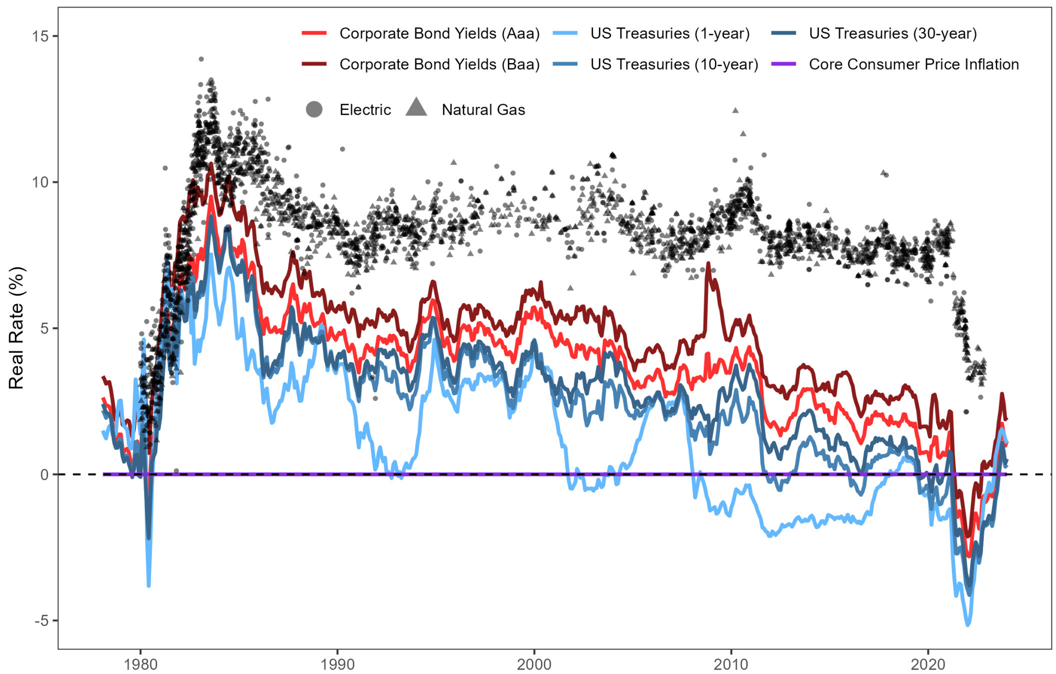
NOTE: Black lines represent the median rating of the utilities active in a given month. We also show bands, in different shades of grey, that cover the 40–60 percentile, 30–70 percentile, 20–80 percentile, 10–90 percentile, and 2.5–97.5 percentile ranges. (Unlike later plots, these *are not* weighted by rate base.) Ratings from C to B– are collapsed to save space.

SOURCE: *Companies (Classic) Screener* (2021) and *Compustat S&P legacy credit ratings* (2019).

A.2 Inflation-Adjusted Rates

In addition to the nominal values plotted in Figure 1, we also plot here the same data in real terms. Real values are calculated by subtracting core CPI.

Figure A.2: Return on Equity and Financial Indicators (Real Terms)



Notes: These figures show the approved return on equity for investor-owned US electric and natural gas utilities. Each dot represents the resolution of one rate case. Real rates are calculated by subtracting core CPI. Between March 2002 and March 2006 30-year Treasury rates are extrapolated from 1- and 10-year rates (using the predicted values from a regressing the 30-year rate on the 1- and 10-year rates).
Sources: Regulatory Research Associates (2024), Moody's (2021a, 2021b), Board of Governors of the Federal Reserve System (2021a, 2021b, 2021c), and US Bureau of Labor Statistics (2021).

B Detail on RoE gap benchmarks

B.1 Benchmarking to the Capital Asset Pricing Model

CAPM: Risk-free rate

The risk-free rate, R_f, is intended to capture the base level of returns from an effectively zero risk investment. Yields on government bonds are the common source for this information, although practitioners can differ over the choice of maturity (e.g. 10-year or 30-year) and the use of forecast future yields instead of past or current rates. These decisions can significantly affect the final cost of equity.[2] We use the contemporaneous yield on 10-year US Treasury bonds for our measure of the risk-free rate.

CAPM: Market risk premium

The market risk premium, *MRP*, captures the difference between the expected equity market rate of return and the risk-free rate.[3] This is generally calculated by taking the average of the difference in returns for some market-wide stock index and the returns for the risk-free rate. While this appears relatively straightforward, the final value can vary significantly depending on numerous factors. These can include: the choice of stock market index (e.g. S&P 500, Dow Jones etc.); the choice of averaging period (e.g. previous 10, 20, 50 years etc.); the return frequency (e.g. monthly, quarterly, or annual returns), and the method of averaging (arithmetic, geometric). These decisions can significantly affect the final cost of equity.[4] Our central case uses annual values for the market risk premium based on estimates that rely on both historical returns and an implied equity premium (Damodaran 2022b, 2022c, 2023). To capture the uncertainty in the market risk premium, our

2. For instance, in January 2018 the current yield on 10-year US Treasury bonds was 2.58%, the average yield from the past 2 years was 2.09%, and the forecast yield from Wolters Klewer (2022) for the next 2 years was 2.97%.

3. $MRP = R_m - R_f$, where R_m is the market return and R_f is the risk-free return.

4. For instance, in January 2018 using annual returns for the S&P 500 compared to the 10-year US Treasury bond and taking the arithmetic average over the past 5, 25, and 75 years produces market risk premiums of 14.8%, 5.2%, and 7.3% respectively (Damodaran 2022b).

"low" case assumes a constant *MRP* of 4.5 percent and our "high" case assumes a constant *MRP* of 7.5 percent. Our central case generally fluctuates between these two values.

CAPM: β

A firm's equity β, is a measure of systematic risk and thus captures the extent to which the returns of the firm in question move in line with overall market returns.[5] Regulated firms like gas and electricity utilities are generally viewed as low risk, exhibiting lower levels of volatility than the market as a whole. The calculation of β is subject to many of the same uncertainties mentioned above, including: the choice of stock market index; the choice of calculation period, and the return frequency.

It is also common to take β estimates from existing data vendors such as Merrill Lynch, Value Line, and Bloomberg. The choice of β depends on the bundle of comparable firms used and how they are averaged. Furthermore, these vendors generally publish β values that incorporate the so-called Blume adjustment to deal with concerns about mean reversion.[6] Because utilities generally have βs below one the adjustment serves to increase β and thus increase the estimated cost of equity produced by the CAPM calculation. Therefore, while the adjustment is plausible for many non-regulated firms, some authors have questioned its applicability to regulated firms like utilities (Michelfelder and Theodossiou 2013).

Lastly, the decision on setting β is complicated by the fact that βs calculated using observed stock returns are dependent on each firm's debt holdings and tax rate, which may differ from the particular utility being studied. To deal with this, an unlevered β can be estimated and then the corresponding levered β can be calculated for a specific debt-to-equity ratio, D/E, and tax rate, τ.[7] Here we take τ

5. β is calculated by estimating the covariance of the returns for the firm in question, R_i, and the market returns, R_m, and then dividing by the variance of the market returns: $\beta = Cov(R_i, R_m)/Var(R_m)$

6. The Blume Adjustment equation is: $\beta_{adjusted} = 0.333(1) + 0.667(\beta)$

7. The Hamada equation relates levered to unlevered β as follows: $\beta = \beta_{unlevered} \times \left[1 + (1-\tau)\frac{D}{E}\right]$

to be the effective federal marginal corporate tax rate and we can directly observe the debt-to-equity ratio, D/E, in our data.

Our central case uses annual values for the utility industry β (Damodaran 2022d). We use the same $\beta_{\text{unlevered}}$ across utilities, and then calculate the β_{levered} for each company based on their observed debt to equity ratio. To capture the uncertainty in β, our "low" case assumes a constant $\beta_{\text{unlevered}}$ of 0.35 and our "high" case assumes a constant $\beta_{\text{unlevered}}$ of 0.4. Our central case generally lies between these two values and produces β_{levered} values mostly ranging from 0.6 to 0.9. The gap is plotted in appendix figures B.1, B.2, and B.3.

B.2 Benchmarking to Debt Yields

As an alternative to the CAPM approach we also consider measures based on benchmarking to wider measures of the cost of debt. The goal of these benchmarks is to answer the question: What would the RoE be today if the spread against the cost of debt had not changed since some baseline date? While relatively simplistic, this kind of approach draws on the intuition that the required return on equity should not stray too far from the required return on debt over time.

We consider a wide variety of debt measurements, including corporate bonds that share the same rating as the utility, the utilities' own return on debt, and two different updating rules based on US Treasury bonds. Throughout our analysis we use January 1995 as the baseline period. The date chosen determines where the gap between utilities' RoE and baseline RoE is zero. Changing the baseline date will shift the overall magnitude of the gap. As long as the baseline date isn't in the middle of a recession, our qualitative results don't depend strongly on the choice. Stated differently, the baseline year determines *when* the average gap is zero, but this is a constant shift that does not affect the overall trend. While January 1995 is not special, we note that picking a much more recent baseline would imply that utilities were substantially and continuously under-compensated for their cost of equity for many years of our early sample.

We first consider a benchmark index of corporate bond yields ("Corp") . Here we compare all utilities to the corporate bond index that is closest to that utility's own, contemporaneous debt rating.[8] To calculate the RoE gap we first find the spread between the approved return on equity and the bond index rate for each utility in each state in a baseline period. We then take this spread during the baseline period and apply it to the future evolution of the bond index rate to get an estimate of the baseline RoE. The RoE gap is the difference between a given utility's allowed return on equity at some point in time and this baseline RoE.

Our second bond benchmark adopts a similar approach to the first but benchmarks against US Treasuries ("UST"). The idea here is to ask: what would the RoE be today if the average spread against US Treasuries had not changed since the baseline date? This measure is calculated in exactly the same way as our first approach except the spread is measured against the 10-year Treasury bond yield in the baseline period, rather than the relevant corporate bond index.

For our third bond benchmark, we modify our benchmark against US Treasures by using an automatic update rule ("UST Auto") that adjusts at *half* the rate of changes in bond yields.[9] This is the approach used by Vermont since 2018. Similar approaches have been used in the past in California and Canada. Whether adjusting at 50% of the change in bond yields is the correct approach is unclear. For instance, Canada has used a 75% adjustment ratio in the past. What is clear is that even using this lower range, we still see a divergence between allowed equity returns today

8. We also examined a comparison against a single Moodys' Baa corporate bond index. Moody's Baa is approximately equivalent to S&P's BBB, a rating equal to or slightly below most of the utilities in our data (see Figure A.1). This avoids issues where utilities' bond ratings may be endogenous to their rate case outcomes. Using a single index also faces fewer data quality challenges. The findings using the single Moody's Baa bond index are broadly equivalent to those using a same rated bond index and our later approach using US Treasuries.

9. Define RoE' as the baseline RoE, B' as the baseline 10-year Treasury bond yield, and B_t as the 10-year Treasury bond yield in year t. RoE in year t is then: $RoE_t = RoE' + (0.5 \times (B_t - B'))$

and various bond yield benchmarks. Vermont PUC uses 10-year US Treasuries and set the baseline period as December 2018, for their plan published in June 2019. (*Green Mountain Power: Multi-Year Regulation Plan 2020–2022* 2020). In our case we also use 10-year Treasuries and set the baseline to January 1995. We simulate the gap between approved RoE and what RoE would have been if every state's utilities commission followed this rule from 1995 onward.[10] The gap is plotted in appendix Figure B.6.

The fourth bond benchmark we use is each utility's own regulator-approved return on debt. The idea here is to ask: what would the RoE be today if the average spread against the regulator-approved return on debt had not changed since the baseline date? Similar to the matched corporate bonds measure, this approach has the virtue of ensuring the benchmark accounts for the different risk characteristics of each utility, including how they change over time. The approved return on debt also appears to be a relatively transparent and uncontroversial aspect of the rate case process, with the regulator-approved value almost exactly matching the utility-proposed value. The gap is plotted in appendix Figure B.7.

B.3 Benchmarking to UK utilities

Finally, our last measure involves benchmarking against allowed returns on equity for gas and electric utilities in the United Kingdom. Here we consider the contemporaneous gap in nominal allowed RoE between the US and UK. Of course there's no particular reason to think the UK regulator is setting the correct RoE, and there are good reasons to think that US state PUCs should not simply adopt UK rates of return – there are many differences between the utility sector and investor environment in the US and UK. Even so, we think this benchmark still provides an interesting comparison.

10. Pre-1995 values are not particularly meaningful, but we can calculate them with the same formula.

The data on UK RoE are taken from various regulatory reports published by the Office of Gas and Electricity Markets (Ofgem).[11] The gap is plotted in appendix Figure B.8.

B.4 Results of RoE Gap Estimates

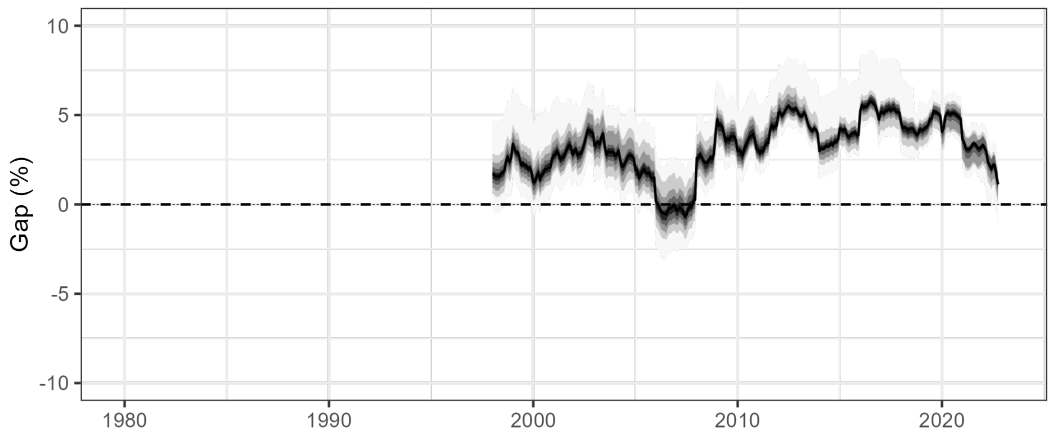
For each of the strategies we utilize, we plot the timeseries of the RoE gap. These are plotted in figures B.1 to B.8. In each plot, we present the median of our RoE gap estimates, weighting by the utility's rate base (in 2019 dollars). Our goal is to show the median of rate base dollar value, rather than the median of utility companies, as the former is more relevant for understanding the impact of the RoE gap. We also show bands, in different shades of grey, that cover the 40–60 percentile, 30–70 percentile, 20–80 percentile, 10–90 percentile, and 2.5–97.5 percentile (all weighted by rate base).

Table B.1 shows our RoE gap results broken out by gas and electric utilities.

Table B.2 shows our RoE gap results broken out by gas and electric utilities. Table D.2 shows our capital impact results for total capital assets across each of our RoE gap benchmarks.

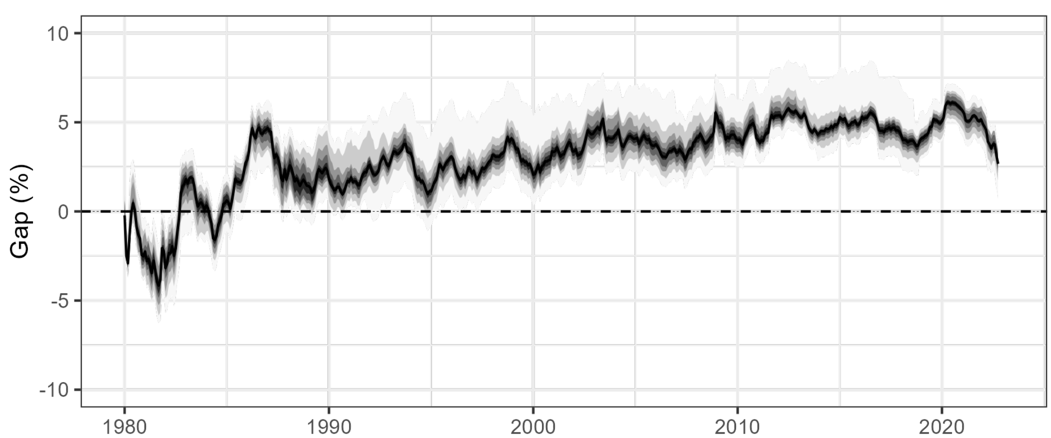
11. We were able to find information on allowed rates of return dating back to 1996. The relevant disaggregation into return on debt and return on equity was more readily available for electric utilities over this entire time period. For natural gas utilities we have this information from 2013 onwards. Importantly, UK rates are set in real terms and so we converted to nominal terms using the inflation indexes cited by the UK regulator.

Figure B.1: Return on equity gap, benchmarking to CAPM (central)



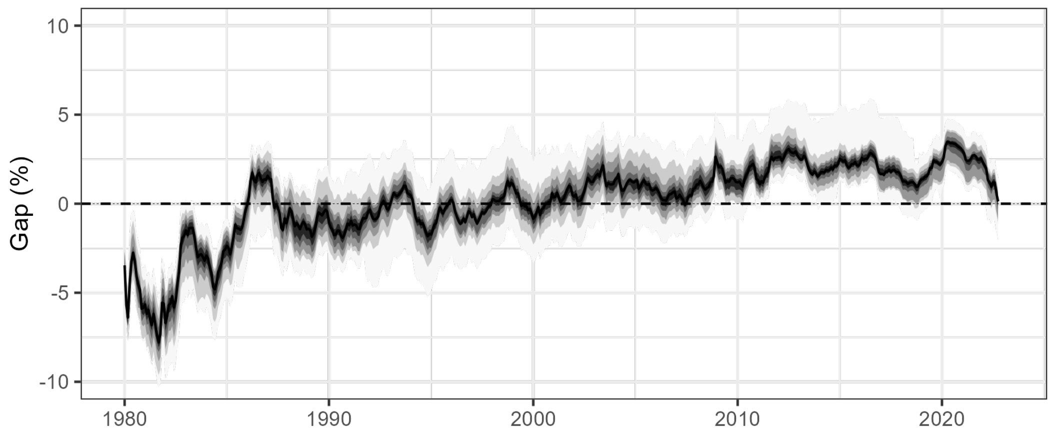
Line represents median; shading represents ranges that cover the central 20, 40, 60, 80, and 95% of total investor-owned utility rate base. See calculation details in section B.1. Note series begins in 1998 due to the coverage of the data sources used for the market risk premium and asset beta.

Figure B.2: Return on equity gap, benchmarking to CAPM (low)



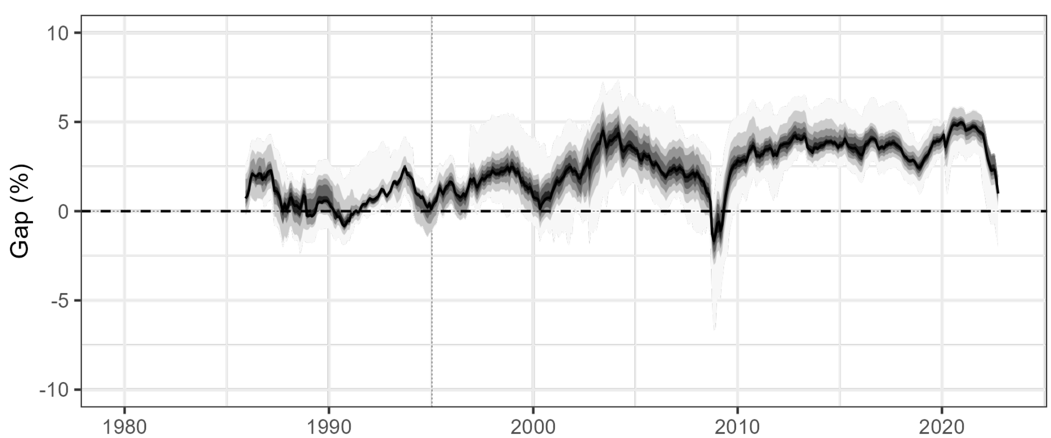
Line represents median; shading represents ranges that cover the central 20, 40, 60, 80, and 95% of total investor-owned utility rate base. See calculation details in section B.1.

Figure B.3: Return on equity gap, benchmarking to CAPM (high)



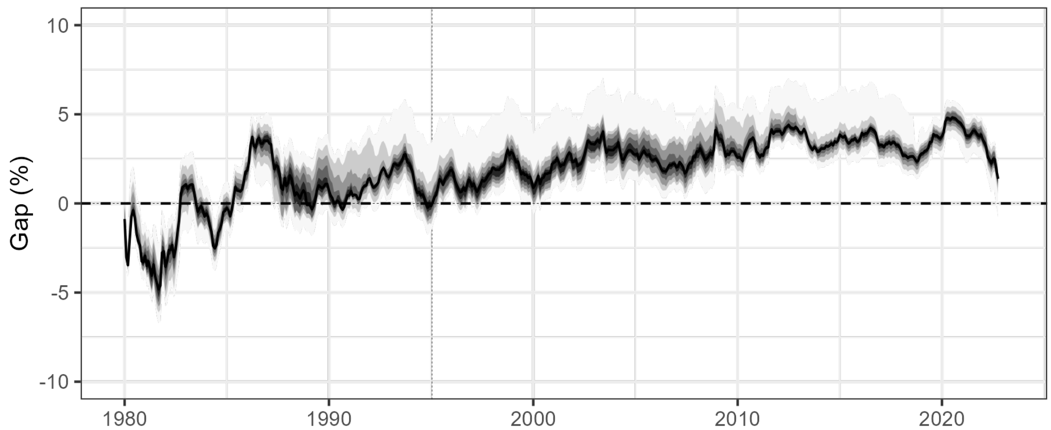
Line represents median; shading represents ranges that cover the central 20, 40, 60, 80, and 95% of total investor-owned utility rate base. See calculation details in section B.1.

Figure B.4: Return on equity gap, benchmarking to same-rated corporate bonds



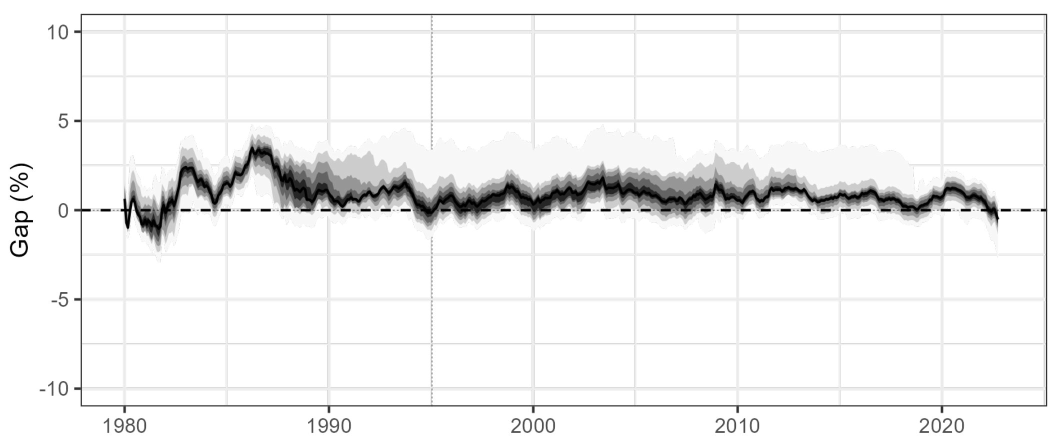
Base year is 1995. Line represents median; shading represents ranges that cover the central 20, 40, 60, 80, and 95% of total investor-owned utility rate base. Series start date is limited by credit rating data. See calculation details in section B.2. Note series begins in 1986 due to the coverage of the data sources used for credit ratings.

Figure B.5: Return on equity gap, benchmarking to 10-year Treasuries



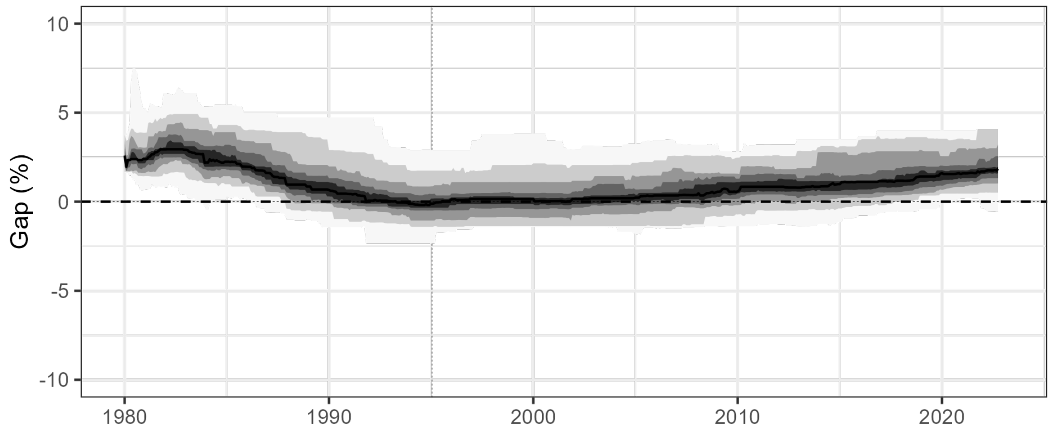
Line represents median; shading represents ranges that cover the central 20, 40, 60, 80, and 95% of total investor-owned utility rate base. See calculation details in section B.2.

Figure B.6: Return on equity gap, benchmarking to 10-year Treasuries (50% adjustment ratio)



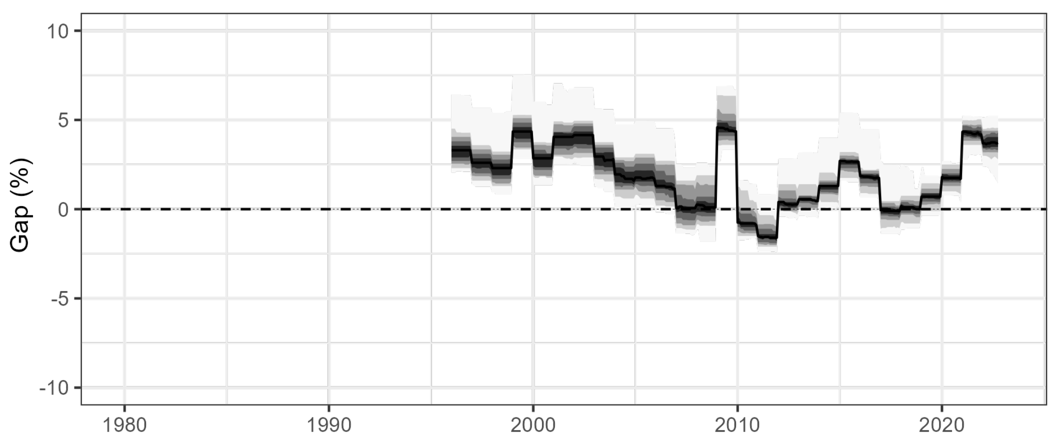
Line represents median; shading represents ranges that cover the central 20, 40, 60, 80, and 95% of total investor-owned utility rate base. See calculation details in section B.2.

Figure B.7: Return on equity gap, benchmarking to approved return on debt



Line represents median; shading represents ranges that cover the central 20, 40, 60, 80, and 95% of total investor-owned utility rate base. See calculation details in section B.2.

Figure B.8: Return on equity gap, compared to UK utilities



Line represents median; shading represents ranges that cover the central 20, 40, 60, 80, and 95% of total investor-owned utility rate base. See calculation details in section B.3. Note series begins in 1996 due to the coverage of the data sources used for UK regulatory decisions.

Table B.1: Return on Equity gap, by different benchmarks (percentage points)

	CAPM central	CAPM high	CAPM low	Corp	RoD	UST	UST Auto	UK
1982		−4.81	−1.27		3.15	−1.77	0.82	
1986		1.10	4.18	1.84	2.11	3.17	3.12	
1990		−1.39	1.63	−0.09	0.81	0.56	0.95	
1994		−1.08	1.90	0.71	−0.02	0.78	0.43	
1998	2.02	0.57	3.49	2.34	0.25	2.31	1.05	2.33
2002	3.50	0.83	3.86	2.24	0.28	2.82	1.24	4.05
2006	−0.22	0.53	3.45	2.40	0.51	2.28	0.79	1.45
2010	3.45	1.63	4.50	3.24	0.87	3.28	1.00	−0.57
2014	3.33	1.93	4.68	3.96	1.11	3.33	0.71	1.31
2018	4.18	1.08	3.91	2.92	1.50	2.65	0.22	0.10
2022	2.31	1.24	3.99	2.80	1.97	2.65	0.11	3.71

Note: Gap percentage figures are a weighted average across utilities, weighted by rate base. “CAPM” compares to various Capital Asset Pricing Model benchmarks. “Corp” compares to same-rated corporate bonds. “RoD” compares to same-utility regulator-approved return on debt. “UST” compares to 10-year US Treasuries. “UST auto” compares to 10-year Treasuries with 50% passthrough. “UK” compares to UK regulatory decisions. For cases where it’s relevant (Corp, RoD, and USTs) the benchmark date is January 1995. See section 4.1 for details of each benchmark calculation.

Table B.2: Return on Equity gap, by different benchmarks, by service type (percentage points)

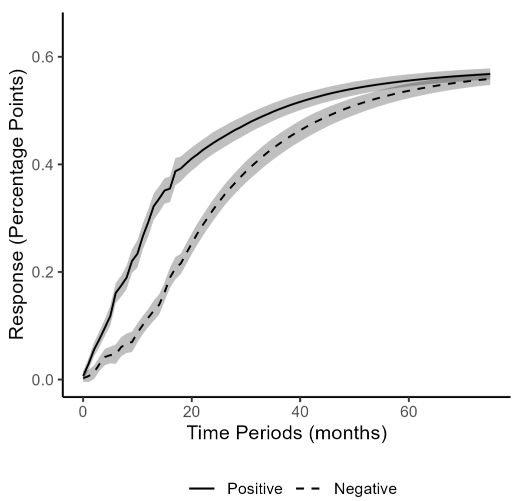
A: Electric	CAPM central	CAPM high	CAPM low	Corp	RoD	UST	UST Auto	UK
1982		−4.91	−1.33		3.19	−1.82	0.78	
1986		1.05	4.16	1.83	2.16	3.14	3.09	
1990		−1.46	1.60	−0.10	0.80	0.52	0.91	
1994		−1.10	1.91	0.69	−0.03	0.78	0.43	
1998	2.03	0.56	3.51	2.34	0.29	2.31	1.05	2.33
2002	3.54	0.82	3.90	2.24	0.33	2.84	1.25	4.05
2006	−0.20	0.55	3.50	2.43	0.55	2.31	0.81	1.45
2010	3.46	1.63	4.52	3.24	0.90	3.25	0.97	−0.57
2014	3.33	1.92	4.67	3.93	1.13	3.27	0.65	1.37
2018	4.17	1.05	3.89	2.90	1.51	2.58	0.15	0.15
2022	2.33	1.25	4.01	2.84	1.98	2.61	0.06	3.53
B: Natural Gas								
1982		−4.09	−0.90		2.81	−1.42	1.11	
1986		1.47	4.31	1.88	1.75	3.42	3.37	
1990		−0.90	1.85	−0.01	0.88	0.86	1.24	
1994		−0.92	1.82	0.99	0.00	0.80	0.45	
1998	1.97	0.68	3.35	2.32	−0.02	2.27	1.01	
2002	3.30	0.84	3.65	2.24	0.02	2.72	1.13	
2006	−0.30	0.43	3.17	2.18	0.30	2.16	0.67	
2010	3.37	1.62	4.40	3.29	0.74	3.42	1.13	
2014	3.36	1.99	4.68	4.14	1.00	3.61	0.99	1.04
2018	4.23	1.21	3.96	3.03	1.45	2.97	0.54	−0.13
2022	2.24	1.19	3.89	2.65	1.94	2.84	0.32	4.41

Note: Gap percentage figures are a weighted average across utilities, weighted by rate base. “CAPM” compares to various Capital Asset Pricing Model benchmarks. “Corp” compares to same-rated corporate bonds. “RoD” compares to same-utility regulator-approved return on debt. “UST” compares to 10-year US Treasuries. “UST auto” compares to 10-year Treasuries with 50% passthrough. “UK” compares to UK regulatory decisions. For cases where it’s relevant (Corp, RoD, and USTs) the benchmark date is January 1995. See text for details of each benchmark calculation. See Table B.1 for consolidated calculations.

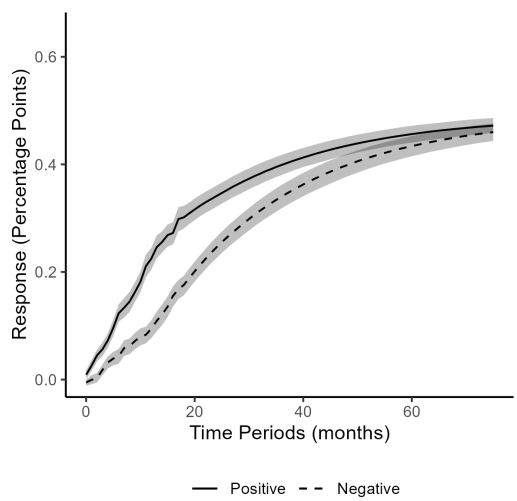
C Detail on Asymmetric Adjustment

Here we include additional information on the asymmetric adjustment analysis. The preferred specification presented in the main paper uses approved rates of return, a benchmark index of 10-year US Treasuries, and aggregates rate case decisions to the state level. We set the number of lags of the return on equity, *m*, and the index, *n*, to 18 months. Two key sources of variation in the results come from the use of proposed or approved rates of return, and the level of aggregation of the panel dataset. To illustrate this we present here robustness analysis across both proposed and approved rates and at three different levels of panel aggregation.

Figure C.1: Asymmetric Cumulative Adjustment Path following Shock to Benchmark Index at Company–State Level



(a) Proposed Rates



(b) Approved Rates

NOTES: Lines represents the cumulative adjustment path following a one percentage point change to the benchmark index. Solid line is for an increase in the index and dashed line is for a decrease. 95% confidence intervals are estimated via block bootstrapping on states, with 1000 replications. The plotted results use a benchmark index of 10-year US Treasuries. Analysis across the two panel columns is conducted with either proposed or approved rates of return. See calculation details in section 4.2.1.

Figure C.1 presents the same results as Figure 3 but with the analysis conducted at the original utility–state panel level. As with the state level results, unit root tests fail to reject non-stationarity in levels and reject non-stationarity in first differences. Using the original utility–state panel also does not radically alter the core findings, with the asymmetric adjustment clearly visible. In fact, because this approach captures both the state-level nature of PUC decision-making and the utility-level variation in how and when rate case decisions are made, we see a wider divergence and a slower pace of adjustment.

For further detail on the results, Table C.1 provides summary information on the different regression specifications. The coefficients are too numerous to be presented here, and are better summarized through their combined effect on the cumulative adjustments plotted in the earlier figures. Nevertheless, the table still provides useful information, including a number of *F*-tests on the different types of coefficients in the vector error correction model.

Table C.1: Asymmetric Adjustments in Return on Equity

Model:	(1)	(2)	(3)	(4)
Prop. or Appr.	Prop.	Appr.	Prop.	Appr.
Group (State)	Yes	Yes	Yes	Yes
Group (Company)			Yes	Yes
ϕ	0.5673	0.5024	0.5786	0.4908
$\sum\beta$+=$\sum\beta$- Fstat	5.848	19.15	5.765	8.139
$\sum\beta$+=$\sum\beta$- pval	0.0156	1.22×10^{-5}	0.0163	0.0043
$\sum\gamma$+=$\sum\gamma$- Fstat	0.4052	0.4598	0.1574	0.0953
$\sum\gamma$+=$\sum\gamma$- pval	0.5244	0.4977	0.6915	0.7575
θ+=θ- Fstat	4.922	13.16	4.489	23.61
θ+=θ- pval	0.0265	0.0003	0.0341	1.18×10^{-6}
Fit statistics				
Observations	21,597	21,597	107,178	107,178
R^2	0.07	0.10	0.02	0.02

Clustered (Year) standard-errors in parentheses
Signif. Codes: ***: 0.01, **: 0.05, *: 0.1

NOTES: "Prop" refers to proposed rates of return and "Appr" refers to approved rates of return. "Group" refers to the level of panel aggregation used for the analysis, and fixed effects are always included at this level where relevant. β coefficients are those on the lagged differenced index terms. γ coefficients are those on the lagged differenced rate of return terms. θ coefficients are those on the error correction term. "Fstat" and "pval" refers to the results of an F-test on the relevant coefficients. ϕ refers to the long-run coefficient from the initial first step regression. See calculation details in section 4.2.1.

D Detail on Capital Impacts

In addition to our first difference specification, we also estimate $\hat{\alpha}$ from the following fixed effects specification.

$$\log(Cap_{i,t}) = \alpha RoE_{i,t}^{gap} + \delta X_{i,t} + \sigma_i + \lambda_t + \epsilon_{i,t} \tag{D.1}$$

As with the first difference setup, an observation is a utility rate case for utility i in year-of-sample t. The dependent variable, $Cap_{i,t}$, is the value of utility plant recorded in the final year of the rate case. We take logs and further isolate the change in the capital base by controlling for the value of utility plant in the first year of the rate case.

Table D.1 shows our results for capital assets. Across our fixed effects specifications (columns 1–4) we find broadly consistent results, with a 1 percentage point increase in the approved RoE gap leading to a ~2–4% increase in capital assets. Our first difference specification (column 5) is repeated here and yields comparable results.

Lastly, Table D.2 shows how our main results vary when using different measures of the RoE gap. Each column refers to one of the eight different benchmarks we calculate. In general we find largely comparable results to those using the gap relative to US Treasuries, although for some of the benchmarks the effect size is smaller and not significant.

Table D.1: Relationship Between Approved Rate of Return and Utility Capital

	FE				FD
Model:	(1)	(2)	(3)	(4)	(5)
Variables					
RoE gap (%)	-0.0786	-0.0842	0.0977**	0.0437**	0.0340**
	(0.0474)	(0.0513)	(0.0402)	(0.0188)	(0.0123)
Fixed-effects					
Year-Month	Yes	Yes	Yes		Yes
Company	Yes	Yes	Yes		
State		Yes	Yes		
Service Type			Yes		
Service Type-Year-Month				Yes	
Service Type-Company				Yes	
Service Type-State				Yes	
Fit statistics					
Observations	1,511	1,511	1,511	1,511	1,298
R^2	0.86	0.88	0.97	0.99	0.38
Within R^2	0.008	0.010	0.05	0.03	0.03
Dep. var. mean	7,677.0	7,677.0	7,677.0	7,677.0	8,253.6

Clustered (Year & Company) standard-errors in parentheses
Signif. Codes: ***: 0.01, **: 0.05, *: 0.1

NOTES: The table uses the gap between approved RoE and 10-year US Treasuries. The dependent variable is log of the utility's total plant in millions of nominal USD. This table only includes utilities that report through FERC Form 1 and so is limited to electric utilities, or combined electricity and natural gas utilities. Columns 1–4 show results with varying levels of fixed effects. Column 5 shows the results with first differences. Our preferred specification is column 5 which uses the same specification as is used in Table 4.

Table D.2: Relationship Between Approved Rate of Return and Utility Capital by Rate of Return Benchmark (Absolute Totals)

Model:	CAPM Central (1)	CAPM Low (2)	CAPM High (3)	Corp (4)	RoD (5)	UK (6)	UST (7)	UST Auto (8)
Variables								
RoE gap (%)	0.0163**	0.0356***	0.0316***	0.0110	0.0073	0.0060	0.0340**	0.0166
	(0.0071)	(0.0122)	(0.0105)	(0.0087)	(0.0074)	(0.0112)	(0.0123)	(0.0143)
Fit statistics								
Observations	1,197	1,295	1,295	1,164	1,295	1,072	1,298	1,298
R^2	0.36	0.38	0.38	0.39	0.36	0.42	0.38	0.37
Within R^2	0.01	0.03	0.03	0.005	0.002	0.002	0.03	0.006
Dep. var. mean	8,571.9	8,266.8	8,266.8	8,676.1	8,266.8	9,509.0	8,253.6	8,253.6

Clustered (Year & Company) standard-errors in parentheses
Signif. Codes: ***: 0.01, **: 0.05, *: 0.1

Notes: The table uses approved RoE. The dependent variable is log of the utility's total plant, as reported to FERC, in millions of nominal USD at the end of the rate case. Columns 1–7 show varying cost of capital benchmarks. The specification used is the same as is used in Table 4.

E Detail on Capital Impacts per kWh

Here we present the same tables as in the main text but using per unit values rather than total values.

Table E.1: Relationship Between Approved Rate of Return and Utility Capital, Opex, and Rate Base (per kWh)

Model:	Capital (1)	Op Ex (2)	Rate Base (3)
Variables			
RoE gap (%)	0.0258**	-0.0230*	0.0092
	(0.0110)	(0.0113)	(0.0160)
Fit statistics			
Observations	1,298	1,300	1,258
R^2	0.34	0.40	0.30
Within R^2	0.009	0.005	0.0004
Dep. var. mean	0.8873	0.1149	0.1376

Clustered (Year & Company) standard-errors in parentheses
Signif. Codes: ***: 0.01, **: 0.05, *: 0.1

NOTES: The table uses approved RoE. Dependent variables are in $ per kWh. This table only includes utilities that report through FERC Form 1 and so is limited to electric utilities, or combined electricity and natural gas utilities. See notes for Table 4.

Table E.2: Relationship Between Approved Rate of Return and Electric Utility Capital and Opex by Expenditure Type and Vertical Integration (per kWh)

Model:	Total (1)	Dist (2)	Trans (3)	Gen (4)	Other (5)
Variables					
RoE gap (%)	0.0294**	0.0247**	0.0308	0.1018	0.0262
	(0.0133)	(0.0120)	(0.0301)	(0.0604)	(0.0181)
Fit statistics					
Observations	978	981	673	738	969
R^2	0.45	0.52	0.38	0.40	0.42
Within R^2	0.01	0.01	0.006	0.02	0.006
Dep. var. mean	1.081	0.3552	0.2475	0.6036	0.0660

Clustered (Year & Company) standard-errors in parentheses
Signif. Codes: ***: 0.01, **: 0.05, *: 0.1

(a) Capital

Model:	Total (1)	Dist (2)	Trans (3)	Gen (4)	Other (5)
Variables					
RoE gap (%)	-0.0125	0.0426**	0.0277	-0.0225	0.0198
	(0.0151)	(0.0206)	(0.0457)	(0.0173)	(0.0137)
Fit statistics					
Observations	905	905	683	685	905
R^2	0.47	0.42	0.45	0.54	0.41
Within R^2	0.002	0.02	0.003	0.006	0.004
Dep. var. mean	0.1581	0.0108	0.0124	0.1296	0.0259

Clustered (Year & Company) standard-errors in parentheses
Signif. Codes: ***: 0.01, **: 0.05, *: 0.1

(b) Operating Expenses

NOTES: Dependent variables are in $ per kWh. This table only includes utilities that report through FERC Form 1 and so is limited to electric utilities. See notes for Table 5.

Table E.3: Relationship Between Approved Rate of Return and Utility Capital (per kWh)

Model:	FE (1)	(2)	(3)	(4)	FD (5)
Variables					
RoE gap (%)	-0.2391***	-0.2194***	0.0281	0.0414*	0.0258**
	(0.0521)	(0.0553)	(0.0193)	(0.0211)	(0.0110)
Fixed-effects					
Year-Month	Yes	Yes	Yes		Yes
Company	Yes	Yes	Yes		
State		Yes	Yes		
Service Type			Yes		
Service Type-Year-Month				Yes	
Service Type-Company				Yes	
Service Type-State				Yes	
Fit statistics					
Observations	1,511	1,511	1,511	1,511	1,298
R^2	0.72	0.80	0.96	0.98	0.34
Within R^2	0.03	0.04	0.003	0.009	0.009
Dep. var. mean	0.8681	0.8681	0.8681	0.8681	0.8873

Clustered (Year & Company) standard-errors in parentheses
Signif. Codes: ***: 0.01, **: 0.05, *: 0.1

NOTES: The table uses approved RoE. The dependent variable is log of the utility's total plant, in $ per kWh. This table only includes utilities that report through FERC Form 1 and so is limited to electric utilities, or combined electricity and natural gas utilities. See notes for Table D.1.

Table E.4: Relationship Between Approved Rate of Return and Utility Capital by Rate of Return Benchmark (per kWh)

Model:	CAPM Central (1)	CAPM Low (2)	CAPM High (3)	Corp (4)	RoD (5)	UK (6)	UST (7)	UST Auto (8)
Variables								
RoE gap (%)	0.0135	0.0268**	0.0236**	0.0025	0.0041	0.0041	0.0258**	0.0120
	(0.0084)	(0.0105)	(0.0091)	(0.0082)	(0.0080)	(0.0095)	(0.0110)	(0.0121)
Fit statistics								
Observations	1,197	1,295	1,295	1,164	1,295	1,072	1,298	1,298
R^2	0.29	0.35	0.35	0.35	0.34	0.45	0.34	0.34
Within R^2	0.004	0.01	0.01	0.0001	0.0004	0.0006	0.009	0.002
Dep. var. mean	0.9307	0.8834	0.8834	0.9052	0.8834	1.050	0.8873	0.8873

Clustered (Year & Company) standard-errors in parentheses
Signif. Codes: ***: 0.01, **: 0.05, *: 0.1

NOTES: The dependent variable is log of the utility's total FERC-reported plant in $ per kWh. See notes for Table D.2.

F Detail on Instrumental Variables

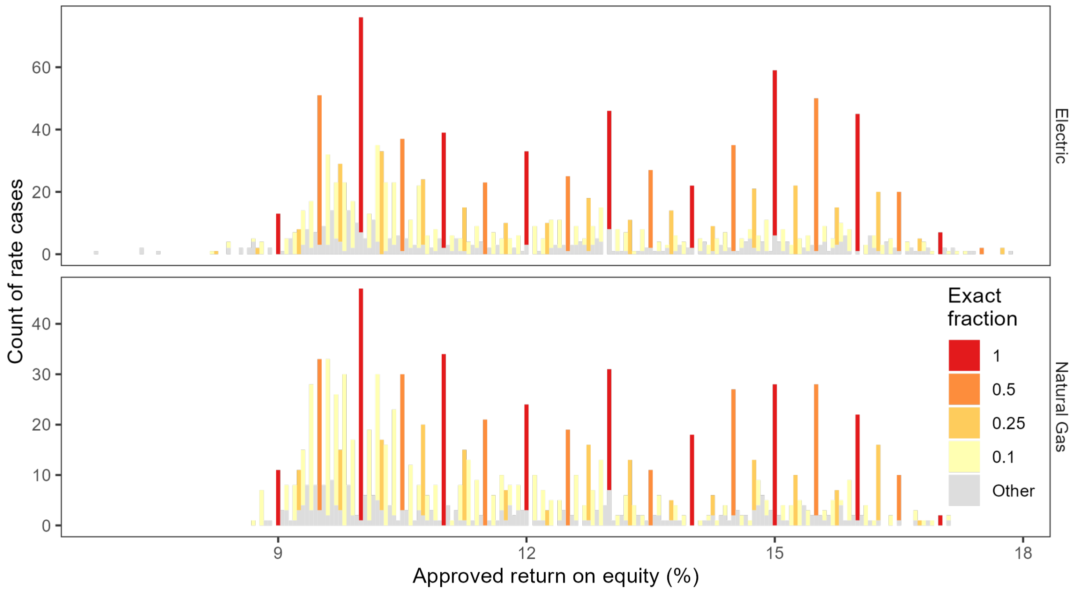
To try and further deal with concerns regarding identification, we explore a number of instrumental variables approaches. Ultimately, we do not consider these as one of our preferred results because of weak first stages.

The first IV strategy we consider is to exploit an apparent predilection toward round numbers, where regulators tend to approve RoE values at integers, halves, quarters, and tenths of percentage points. We believe the actual, unknown, cost of equity is smoothly distributed. There is therefore some unobserved RoE* that is unrounded. The regulatory process often then rounds from RoE* to the nearest multiple of 10 or 25 basis points (bp). We argue that this introduces an exogenous source of variation into the actual approved RoE. Our rounding IV does appear to be more plausibly exogenous given the arbitrary nature of the rounding phenomenon we observe. Unfortunately though the instrument does not produce a strong first stage. Here we show this based on rounding to 50 basis points but the same point holds for other rounding levels. We also include a specification that rounds to 500 basis points to capture the idea raised by Rode and Fischbeck (2019) that regulators seemed reluctant to set a nominal RoE below 10 percentage points in the later years of our sample. Additionally, an IV LATE monotonicity argument is hard to justify for this instrument.

Even so, the existence of such an arbitrary phenomenon in our setting is relevant, and can be seen clearly in Figure F.1. Small deviations created by rounding have large implications for utility revenues and customer payments. If for instance, a PUC rounds in a way that changes the allowed RoE by 10 basis points (0.1%), the allowed revenue on the existing rate base for the average electric utility in 2019 would change by $114 million (the median is lower, at $52 million).

Our second IV strategy focuses on the use of a single test year as the basis for determining the costs in a given rate case. In each rate case the regulator determines

Figure F.1: Return on equity is often approved at round numbers



Colors highlight values of the nominal approved RoE that fall exactly on round numbers. More precisely, values in red are integers. Values in dark orange are integers plus 50 basis points (bp). Lighter orange are integers plus 25 or 75 bp. Yellow are integers plus one of {10, 20, 30, 40, 60, 70, 70, 80, 90} bp. All other values are gray. Histogram bin widths are 5 bp. Non-round values remain gray if they fall in the same histogram bin as a round value. In that case, the bars are stacked.
SOURCE: Regulatory Research Associates (2024).

a test year that forms the basis for the costs estimated for the rate case period. The approach to determining this test year varies across states and over time. Some states use a historical year, while others use a future year. Some states use values from the final month of their chosen year, while others use values averaged over the entire year. The selection of the test year method may therefore lead to variation in the underlying cost assumptions, including the cost of equity, used for a given rate case. This variation with be a function of the method used and the time when each rate case is ultimately filed. If we assume the test year method is a largely arbitrary feature of different states' regulatory process, this may lead to plausibly exogenous variation in our return on equity gap. We therefore construct our instrument by focusing on the variation the test year method creates in the contemporaneous 10-year treasury bond yield that will factor into the rate case process. We first calculate the assumed yield if all rate cases used values averaged over an entire historical test year that is the last full year before a rate case is filed. We then calculate the assumed yield given the test year method rate cases actually use. Here we use information in our data on both the method used, the approach normally adopted by each state, and the end date of the test year chosen. We take the difference between these two assumed yields on 10-year treasuries as our instrument for the underlying cost of equity.

Again, this proposed instrument lacks power in the first stage, so ultimately we do not use it. All of these instruments are summarized in Table F.1.

Table F.1: First Stage Regressions for Various Instruments

Model:	(1)	(2)	(3)
Variables			
| IV Rounding (50bp) | × Sign = -1	-0.3105		
	(0.3106)		
| IV Rounding (50bp) | × Sign = 1	-0.3531		
	(0.3139)		
| IV Rounding (500bp) | × Sign = -1		0.0674	
		(0.1466)	
| IV Rounding (500bp) | × Sign = 1		0.3496***	
		(0.1277)	
IV Test Year			0.0305
			(0.0198)
Fixed-effects			
Year-Month	Yes	Yes	Yes
Company	Yes	Yes	Yes
State	Yes	Yes	Yes
Service Type	Yes	Yes	Yes
Fit statistics			
Observations	3,546	3,546	3,439
R^2	0.85	0.85	0.85
Within R^2	0.0008	0.02	0.0009
Dependent variable mean	6.0	6.0	6.0
Wald (joint nullity), stat.	0.84	4.2	2.4

Clustered (Year & Company) standard-errors in parentheses
Signif. Codes: ***: 0.01, **: 0.05, *: 0.1

NOTES: The dependent variable is the RoE gap (spread between approved RoE and 10-year US Treasuries). Column 1 shows the instrument using rounding (50 basis points). Column 2 shows the instrument using rounding (500 basis points). Column 3 shows the instrument using test year method.

G Detail on Excess Consumer Cost

Table G.1 summarizes our estimates of the excess cost for utility customers. Here we multiply the rate base by the RoE gap to come up with a measure of the additional payments made to cover the premium in equity returns. We present results that take the observed rate base as a given – the "fixed" row – and also present results that include the rate base with the additional increases estimated above – the "adjust" row. The increment from the "fixed" to "adjust" row is meaningful (billions of dollars in some specifications), but smaller than the gap documented in the "fixed" row.

To ensure these excess costs are calculated for all utilities in our sample, we must remedy the missing rate base data for some utilities, particularly in the earlier years of our sample.[12] To do this we extend the series using an estimate of the average growth rate for the rate base over time.[13]

Table G.1: Average annual excess costs, by different benchmarks (2019$ billion per year)

	CAPM central	CAPM high	CAPM low	Corp	RoD	UST	UST Auto	UK
Fixed	6.19	2.75	9.07	5.48	1.73	6.26	1.89	3.36
Adjusted	7.16	3.07	10.60	6.26	1.93	7.06	2.03	3.82

Note: Excess payments are totals for all investor-owned utilities in the US, in billions of 2019 dollars per year. To ensure comparability between benchmarks with differing levels of completeness, values are the average annual excess cost over the past three decades from 1992–2022. Missing rate base data for utilities in our sample was filled based on the estimated average growth rate of the rate base over time. The "fixed" row takes the observed rate base as fixed and estimates excess payments. The "adjust" row also accounts for changes in the rate base size, as estimated in Table 2 column 3. For cases where it's relevant the benchmark date is January 1995. See section 4.1 for details of each benchmark calculation.

12. Approved rate base data is available for 95% of utilities in 2020 and 65% of utilities in 2000.

13. We regress approved rate base on time, controlling for utility by state by service type fixed effects. Within each grouping of utility, state, and service type, we start with the first non-missing value and linearly extended backwards assuming the rate base changes from period to period according to our estimated growth rate.

Table G.2 shows our excess consumer cost results broken out by gas and electric utilities.

Table G.2: Excess costs, by different benchmarks and by service type (2019$ billion per year)

A: Electric	CAPM central	CAPM high	CAPM low	Corp	RoD	UST	UST Auto	UK
Fixed	5.11	2.22	7.53	4.56	1.45	5.11	1.51	3.09
Adjusted	5.91	2.48	8.79	5.21	1.63	5.75	1.62	3.51
B: Natural Gas								
Fixed	1.08	0.53	1.54	0.92	0.28	1.15	0.37	0.27
Adjusted	1.25	0.59	1.80	1.05	0.31	1.31	0.40	0.31

Note: Excess payments are totals for all investor-owned utilities in the US, in billions of 2019 dollars per year. To ensure comparability between benchmarks with differing levels of completeness, values are the average annual excess cost over the past three decades from 1992–2022. Missing rate base data for utilities in our sample was interpolated based on the estimated average growth rate of the rate base over time. The “fixed” row takes the observed rate base as fixed and estimates excess payments. The “adjust” row also accounts for changes in the rate base size, as estimated in Table 2 column 3. For cases where it’s relevant the benchmark date is January 1995. See section 4.1 for details of each benchmark calculation.

Data

Australian Energy Regulator. 2020. *International regulatory approaches to rate of return - Pathway to Rate of Return 2022.* December 16, 2020. Accessed August 13, 2022. https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/international-regulatory-approaches-to-rate-of-return-pathway-to-rate-of-return-2022.

Board of Governors of the Federal Reserve System. 2021a. *1-Year Treasury Constant Maturity Rate.* FRED, Federal Reserve Bank of St. Louis, April 1, 2021. Accessed April 7, 2021. https://fred.stlouisfed.org/series/GS1.

———. 2021b. *10-Year Treasury Constant Maturity Rate.* FRED, Federal Reserve Bank of St. Louis, April 1, 2021. Accessed April 7, 2021. https://fred.stlouisfed.org/series/GS10.

———. 2021c. *30-Year Treasury Constant Maturity Rate.* FRED, Federal Reserve Bank of St. Louis, April 1, 2021. Accessed April 7, 2021. https://fred.stlouisfed.org/series/GS30.

Companies (Classic) Screener. 2021. S&P Global Market Intelligence, January. Accessed March 17, 2021. https://platform.marketintelligence.spglobal.com/web/client?auth=inherit#office/screener.

Compustat S&P legacy credit ratings. 2019. Wharton Research Data Service, October 18, 2019. Accessed March 12, 2021.

Damodaran, Aswath. 2022a. *Cost of Capital by Industry.* Stern School of Business at New York University, August 13, 2022. Accessed August 13, 2022. https://pages.stern.nyu.edu/~adamodar/New_Home_Page/dataarchived.html.

———. 2022b. *Historical Returns on Stocks, Bonds and Bills.* Stern School of Business at New York University, August 13, 2022. Accessed August 13, 2022. https://pages.stern.nyu.edu/~adamodar/New_Home_Page/dataarchived.html.

———. 2022c. *Implied Equity Risk Premiums.* Stern School of Business at New York University, August 13, 2022. Accessed August 13, 2022. https://pages.stern.nyu.edu/~adamodar/New_Home_Page/dataarchived.html.

———. 2022d. *Levered and Unlevered Beta by Industry.* Stern School of Business at New York University, August 13, 2022. Accessed August 13, 2022. https://pages.stern.nyu.edu/~adamodar/New_Home_Page/dataarchived.html.

Economic Consulting Associates. 2020. *Methodologies and parameters used to determine the allowed or target revenue of transmission system operators - Report for ACER.* December 16, 2020. Accessed August 13, 2022. https://www.eca-uk.com/2018/11/05/acer-publishes-eca-report-on-eu-revenue-setting-approaches-for-gas-transmission/.

Energy Information Administration. 2024a. *Annual Electric Power Industry Report Form EIA-861.* February 24, 2024. Accessed February 24, 2024. https://www.eia.gov/electricity/data/eia861/.

———. 2024b. *Annual Report of Natural and Supplemental Gas Supply and Disposition Form EIA-176.* February 24, 2024. Accessed February 24, 2024. https://www.eia.gov/naturalgas/ngqs/.

Ice Data Indices, LLC. 2021a. *ICE BofA AA US Corporate Index Effective Yield.* FRED, Federal Reserve Bank of St. Louis, April 6, 2021. Accessed April 7, 2021. https://fred.stlouisfed.org/series/BAMLC0A2CAAEY.

———. 2021b. *ICE BofA AAA US Corporate Index Effective Yield.* FRED, Federal Reserve Bank of St. Louis, April 6, 2021. Accessed April 7, 2021. https://fred.stlouisfed.org/series/BAMLC0A1CAAAEY.

Ice Data Indices, LLC. 2021c. *ICE BofA BB US High Yield Index Effective Yield.* FRED, Federal Reserve Bank of St. Louis, April 6, 2021. Accessed April 7, 2021. https://fred.stlouisfed.org/series/BAMLH0A1HYBBEY.

———. 2021d. *ICE BofA BBB US Corporate Index Effective Yield.* FRED, Federal Reserve Bank of St. Louis, April 6, 2021. Accessed April 7, 2021. https://fred.stlouisfed.org/series/BAMLC0A4CBBBEY.

———. 2021e. *ICE BofA CCC & Lower US High Yield Index Effective Yield.* FRED, Federal Reserve Bank of St. Louis, April 6, 2021. Accessed April 7, 2021. https://fred.stlouisfed.org/series/BAMLH0A3HYCEY.

———. 2021f. *ICE BofA Single-A US Corporate Index Effective Yield.* FRED, Federal Reserve Bank of St. Louis, April 6, 2021. Accessed April 7, 2021. https://fred.stlouisfed.org/series/BAMLC0A3CAEY.

———. 2021g. *ICE BofA Single-B US High Yield Index Effective Yield.* FRED, Federal Reserve Bank of St. Louis, April 6, 2021. Accessed April 7, 2021. https://fred.stlouisfed.org/series/BAMLH0A2HYBEY.

Moody's. 2021a. *Moody's Seasoned Aaa Corporate Bond Yield.* FRED, Federal Reserve Bank of St. Louis, April 1, 2021. Accessed April 7, 2021. https://fred.stlouisfed.org/series/AAA.

———. 2021b. *Moody's Seasoned Baa Corporate Bond Yield.* FRED, Federal Reserve Bank of St. Louis, April 1, 2021. Accessed April 7, 2021. https://fred.stlouisfed.org/series/BAA.

Regulatory Research Associates. 2024. *Rate Case History.* S&P Global Market Intelligence, February. Accessed February 22, 2024. https://platform.marketintelligence.spglobal.com/web/client?auth=inherit#industry/pastRateCases?Type=1.

Selvans, Zane A., Christina M. Gosnell, Austen Sharpe, Bennett Norman, Trenton Bush, Zach Schira, Katherine Lamb, Dazhong Xia, and Ella Belfer. 2024. *Public Utility Data Liberation Project Data Release.* February 5, 2024. https://doi.org/10.5281/zenodo.10569540.

UK Regulatory Network. 2020. *UKRN Cost of Capital Annual Report 2020.* December 16, 2020. Accessed August 13, 2022. https://www.ukrn.org.uk/publications/ukrn-cost-of-capital-annual-report-2020/.

US Bureau of Labor Statistics. 2021. *Consumer Price Index for All Urban Consumers: All Items in U.S. City Average.* FRED, Federal Reserve Bank of St. Louis, March 10, 2021. Accessed April 7, 2021. https://fred.stlouisfed.org/series/CPIAUCSL.

US Energy Information Administration. 2020. *2019 Utility Bundled Retail Sales – Total.* October 2, 2020. Accessed April 28, 2021. https://www.eia.gov/electricity/sales_revenue_price/xls/table10.xlsx.

Wolters Klewer. 2022. *Blue Chip Economic Indicators.* Wolters Klewer, August 13, 2022. Accessed August 13, 2022. https://www.wolterskluwer.com/en/solutions/vitallaw-law-firms/blue-chip.

Software Citations

Bache, Stefan Milton, and Hadley Wickham. 2020. *magrittr: A Forward-Pipe Operator for R.* 2.0.1. https://cran.r-project.org/package=magrittr.

Dowle, Matt, and Arun Srinivasan. 2021. *data.table: Extension of 'data.frame'.* 1.14.0. https://cran.r-project.org/package=data.table.

Fabri, Antoine. 2020. *safejoin: Join safely and Deal with Conflicting Columns.* 0.1.0. August 19, 2020.

François, Romain, Jeroen Ooms, Neal Richardson, and Apache Arrow. 2021. *arrow: Integration to 'Apache' 'Arrow'.* 3.0.0. https://cran.r-project.org/package=arrow.

Gaure, Simen. 2013. "lfe: Linear group fixed effects." User documentation of the 'lfe' package, *The R Journal* 5, no. 2 (December): 104–117. https://journal.r-project.org/archive/2013/RJ-2013-031/RJ-2013-031.pdf.

Grolemund, Garrett, and Hadley Wickham. 2011. "Dates and Times Made Easy with lubridate." *Journal of Statistical Software* 40 (3): 1–25. https://www.jstatsoft.org/v40/i03/.

Henry, Lionel, and Hadley Wickham. 2020a. *purrr: Functional Programming Tools.* 0.3.4. https://cran.r-project.org/package=purrr.

———. 2020b. *rlang: Functions for Base Types and Core R and 'Tidyverse' Features.* 0.4.10. https://cran.r-project.org/package=rlang.

———. 2020c. *tidyselect: Select from a Set of Strings.* 1.1.0. https://cran.r-project.org/package=tidyselect.

Hester, Jim. 2020. *glue: Interpreted String Literals.* 1.4.2. https://cran.r-project.org/package=glue.

Iannone, Richard, Joe Cheng, and Barret Schloerke. 2020. *gt: Easily Create Presentation-Ready Display Tables.* 0.2.2. https://cran.r-project.org/package=gt.

Köster, Johannes, and Sven Rahmann. 2018. "Snakemake—a scalable bioinformatics workflow engine." *Bioinformatics* 34, no. 20 (May): 3600–3600. https://doi.org/10.1093/bioinformatics/bty350.

Kuhn, Max. 2020. *caret: Classification and Regression Training.* 6.0-86. https://cran.r-project.org/package=caret.

Microsoft Corporation and Steve Weston. 2020. *doParallel: Foreach Parallel Adaptor for the 'parallel' Package.* 1.0.16. https://cran.r-project.org/package=doParallel.

Müller, Kirill. 2020. *here: A Simpler Way to Find Your Files.* 1.0.1. https://cran.r-project.org/package=here.

Müller, Kirill, and Hadley Wickham. 2021. *tibble: Simple Data Frames.* 3.1.0. https://cran.r-project.org/package=tibble.

Neuwirth, Erich. 2014. *RColorBrewer: ColorBrewer Palettes.* 1.1-2. https://cran.r-project.org/package=RColorBrewer.

Ooms, Jeroen. 2019. *curl: A Modern and Flexible Web Client for R.* 4.3. https://cran.r-project.org/package=curl.

Pebesma, Edzer. 2018. "Simple Features for R: Standardized Support for Spatial Vector Data." *The R Journal* 10 (1): 439–446. https://doi.org/10.32614/RJ-2018-009. https://doi.org/10.32614/RJ-2018-009.

R Core Team. 2020. *R: A Language and Environment for Statistical Computing.* 4.0.3. Vienna, Austria: R Foundation for Statistical Computing. https://www.r-project.org/.

Robinson, David, Alex Hayes, and Simon Couch. 2021. *broom: Convert Statistical Objects into Tidy Tibbles.* 0.7.5. https://cran.r-project.org/package=broom.

Teetor, Nathan. 2018. *zeallot: Multiple, Unpacking, and Destructuring Assignment.* 0.1.0. https://cran.r-project.org/package=zeallot.

Ushey, Kevin. 2021. *renv: Project Environments.* 0.13.0. https://cran.r-project.org/package=renv.

Wickham, Hadley. 2016. *ggplot2: Elegant Graphics for Data Analysis.* Springer-Verlag New York. https://ggplot2.tidyverse.org.

———. 2019. *stringr: Simple, Consistent Wrappers for Common String Operations.* 1.4.0. https://cran.r-project.org/package=stringr.

———. 2020. *tidyr: Tidy Messy Data.* 1.1.2. https://cran.r-project.org/package=tidyr.

Wickham, Hadley, Mara Averick, Jennifer Bryan, Winston Chang, Lucy D'Agostino McGowan, Romain François, Garrett Grolemund, et al. 2019. "Welcome to the tidyverse." *Journal of Open Source Software* 4 (43): 1686. https://doi.org/10.21105/joss.01686.

Wickham, Hadley, and Jennifer Bryan. 2019. *readxl: Read Excel Files.* 1.3.1. https://cran.r-project.org/package=readxl.

Wickham, Hadley, Romain François, Lionel Henry, and Kirill Müller. 2021. *dplyr: A Grammar of Data Manipulation.* 1.0.4. https://cran.r-project.org/package=dplyr.

Wickham, Hadley, and Jim Hester. 2020. *readr: Read Rectangular Text Data.* 1.4.0. https://cran.r-project.org/package=readr.

Wickham, Hadley, Jim Hester, Winston Chang, Kirill Müller, and Daniel Cook. 2021. *memoise: Memoisation of Functions.* 2.0.0. https://cran.r-project.org/package=memoise.

Zeileis, Achim, and Gabor Grothendieck. 2005. "zoo: S3 Infrastructure for Regular and Irregular Time Series." *Journal of Statistical Software* 14 (6): 1–27. https://doi.org/10.18637/jss.v014.i06.

Energy Policy 133 (2019) 110891

Contents lists available at ScienceDirect

Energy Policy

journal homepage: www.elsevier.com/locate/enpol

Regulated equity returns: A puzzle

David C. Rode[a,*], Paul S. Fischbeck[a,b]

[a] Department of Social and Decision Sciences, Carnegie Mellon University, Pittsburgh, PA, 15213, USA
[b] Department of Engineering and Public Policy, Carnegie Mellon University, Pittsburgh, PA, 15213, USA

ARTICLE INFO

Keywords:
Discount rate
Electric utility
Rate of return regulation
Valuation

ABSTRACT

Based on a database of U.S. electric utility rate cases spanning nearly four decades, the returns on equity authorized by regulators have exhibited a large and growing premium over the riskless rate of return. This growing premium does not appear to be explained by traditional asset-pricing models, often in direct contrast to regulators' stated intent. We suggest possible alternative explanations drawn from finance, public policy, public choice, and the behavioral economics literature. However, absent some normative justification for this premium, it would appear that regulators are authorizing excessive returns on equity to utility investors and that these excess returns translate into tangible profits for utility firms.

1. Introduction

In economics, the equity-premium puzzle refers to the empirical phenomenon that returns on a diversified equity portfolio have exceeded the riskless rate of return on average by more than can be explained by traditional models of compensation for bearing risk. Since Mehra and Prescott's (1985) initial paper on the subject, a large body of research has attempted to explain away the puzzle, but without much success (Mehra and Prescott, 2003). The most likely explanations for the premium appear to reside outside of classical equilibrium models. We call the reader's attention to the Mehra-Prescott puzzle as a means of introducing our instant problem, of which it may be considered an applied case. Simply put: why are the equity returns authorized by electric utility regulators so high, given that riskless rates are so low?

Our scope is as follows. We employ a much larger dataset than has previously been examined in the literature and seek to explain the rates of return *authorized* by state electric utility regulators. We investigate the extent to which the actual returns authorized can be explained by the Capital Asset Pricing Model (CAPM), which regulators (and others) purport to use. We also examine whether the CAPM is capable of explaining the clear trend of rising risk premiums present over the last four decades in electric utility rate cases.

While previous studies have investigated rates of return for regulated electric utilities, the majority of this work has either examined *actual* rates of return to utility stockholders, relied on very limited samples of rate cases, or tested a variety of hypotheses connecting utility earnings to various structural and institutional factors. Table 1 summarizes the previous literature most similar to our study. By contrast, our study employs a far larger sample of rate cases (1,596) than previously examined in the literature. In addition, our focus on authorized rates of return highlights the impact of regulatory rate-setting on consumers, as opposed to stockholders, to the extent that authorized rates are used to set utility revenue requirements, while earned returns accrue to stockholders. This setting also enables us to analyze rate-setting in the context of regulatory decision-making. Actual rates of return earned by utilities can differ from the rates of return authorized by regulators due to factors such as the impact of weather on demand, but primarily due to the operational performance of a utility, including its ability to operate efficiently and control costs to those approved by regulators.

This regulated equity return puzzle is important not just from a theoretical asset-pricing perspective, but also for very practical reasons. The database used in this study reflects more than $3.3 trillion (in 2018 dollars) in cumulative rate-base exposure.[1] An error or bias of merely one percentage point in the allowed return would imply tens of billions of dollars in additional cost for ratepayers in the form of higher retail power prices and could play a profound role in the allocation of investment capital. Coupled with utilities' tendencies toward excessive capital accumulation under rate regulation (Averch and Johnson, 1962; Spann, 1974; Courville, 1974; Hayashi and Trapani, 1976; Vitaliano

* Corresponding author.
E-mail addresses: rode@andrew.cmu.edu (D.C. Rode), fischbeck@cmu.edu (P.S. Fischbeck).

[1] This figure reflects the simple cumulative sum of authorized rate bases across all cases. Because rate-base decisions may remain in place for several years, this sum most likely underestimates the actual figure, which should be the authorized rate base in each year examined, whether or not a new case was decided. We cite this figure merely as evidence of the substantial magnitude of the costs at stake.

https://doi.org/10.1016/j.enpol.2019.110891
Received 22 January 2019; Received in revised form 18 July 2019; Accepted 19 July 2019
Available online 25 July 2019
0301-4215/

Table 1
Previous studies of the determinants of electric utility rates of return.

Study	Sample	Description
Joskow (1972)	20 cases in New York between 1960 and 1970	Only capital markets parameter included was cost of debt. Focused on the requested rate of return.
Joskow (1974)	174 cases between 1958 and 1972	No CAPM parameters tested. Regulators tended to ignoring overearning as long as prices were falling.
Hagerman and Ratchford (1978)	79 survey responses from utilities about their last rate case	Used authorized rates. Found positive coefficients related to beta and the debt/equity ratio.
Roberts et al. (1978)	59 cases from 4 Florida utilities between 1960 and 1976	No CAPM parameters tested. Only structural factors examined.
Roll and Ross (1983)	Utility stock returns between 1925 and 1980	No authorized returns used. CAPM underestimates returns relative to the APT.
Pettway and Jordan (1987)	58 electric service companies between 1969 and 1976	Used stockholder returns only.
Binder and Norton (1999)	92 firms	Used stockholder returns to estimate beta. Suggested that regulation causes cash flow "buffering" and that firms may be underearning.
PJM Interconnection (2016)	22 regulated firms between 2000 and 2015	Examined stockholder returns and found regulated firms had positive alpha.
Haug and Wieshammer (2019)	N/A	Regulators in continental Europe "uniformly adopt the [CAPM]" and courts have ruled that the authorized rates are too low. The opposite finding to our study.

and Stella, 2009), the magnitude of the problem makes it incumbent on the industry and regulators to get it right.

There are also policy implications for market design and regulation. A recent PJM Interconnection (2016) study compared and contrasted entry and exit decisions in competitive and regulated markets to evaluate the efficiency of competitive markets for power. One finding that emerged from the study was that regulated utilities appeared to be "overearning" and had generated positive alpha, while competitive firms had not generated positive alpha.[2] Although the study used a limited time window of rate case data and focused on utility stock returns, not returns authorized by regulators, its findings are consistent with those we explore in more detail here.

As an old joke goes, an economist is someone who sees something work in practice and asks whether it can work in theory. Undoubtedly, the utility sector has been successful in attracting capital over the past four decades. We cannot necessarily say, however, that had returns been consistent with the dominant theoretical model used (and thus lower), this would still have been the case. Accordingly, this article also raises the question of whether our theoretical models of required return and asset pricing must be refined. Or, at the very least, whether there are important considerations that must be accounted for in the application of those models to the regulated electric utility industry.

In this article, therefore, we examine the historical data on authorized rates of return on equity in U.S. electric utility rate cases. We compare these rates of return to several conventional benchmarks and the classical theoretical asset-pricing model. We demonstrate that the spread between authorized equity returns (and also earned equity returns) and the riskless rate has grown steadily over time. We investigate whether this growing spread can be explained by classical asset-pricing parameters and conclude that it cannot. We then evaluate possible explanations outside of classical finance to suggest fruitful paths for future research. Specifically, we investigate whether the addition of variables for commission selection and case adjudication contribute explanatory power, in line with existing theories in the pubic choice literature. We conclude with a discussion of the policy implications of the observed premiums and how regulatory rate-setting could be adjusted to mitigate higher premiums.

Section 2 reviews the legal, regulatory, and financial foundations of rate of return determination for utilities. Section 3 describes the data used in our analysis and defines the risk premium on which our analysis is based. Section 4 presents the results of our analysis and outlines the various factors explored, including both classical financial factors and factors outside of the classical paradigm. Section 5 highlights the policy implications of our research, suggests potential mitigating strategies, and concludes.

2. Regulated equity returns and the Capital Asset Pricing Model

At the outset, let us make clear that we are addressing only *regulated* rates of return on equity in this article. We draw no conclusions or inferences about the behavior of returns on non-regulated assets. Our focus is limited to regulated returns because in such cases it is regulators who are tasked with standing in for the discipline of a competitive market and ensuring that returns are just and reasonable. For more than a century, U.S. courts have ruled consistently in support of this objective, while recognizing that achieving it requires consideration of numerous factors that are subject to change over time. The task set to regulators, then, is to approximate what a competitive market would provide, *if one existed.*

Mindful of this mandate, two U.S. Supreme Court decisions are commonly thought to provide the conceptual foundation for utility rate-of-return regulation. In *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia* (262 U.S. 679 (1923)), the Court identified eight factors that were to be considered in determining a fair rate of return, ruling that "[t]he return should be reasonable, sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economic management, to maintain and support its credit and enable it to raise money necessary for the proper discharge of its public duties." This position was made more concrete in *Federal Power Commission v. Hope Natural Gas Company* (320 U.S. 591 (1944)), wherein the Court ruled that the "return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks."

In both *Bluefield* and *Hope*, the Court sought to balance the need for utilities to attract capital sufficient to discharge their duties with the need for regulators to protect ratepayers from what would otherwise be rent-seeking monopolists. These efforts in determining "just and reasonable" returns received significant assistance in the 1960s when groundbreaking advances in asset-pricing theory were made in finance. Specifically, the development of the Capital Asset Pricing Model (CAPM) (Sharpe, 1964; Lintner, 1965; Mossin, 1966) provided a rigorous framework within which the question of the appropriate rate of return could be addressed in an objective fashion. The security market line representation of the CAPM [1] set out the equilibrium rate of return on equity, r_E, as the sum of the rate of return on a riskless asset,

[2] In asset pricing models, positive alpha is evidence of non-equilibrium returns, meaning that investors are receiving compensation in excess of what would be required for bearing the risks they have assumed.

r_f, and a premium related to the level of risk being assumed that was defined in relation (through the factor β) to the expected excess rate of return on the overall market for capital, r_m.

$$r_E = r_f + \beta(r_m - r_f) \quad (1)$$

It is outside of the scope of this paper to delve too deeply into the foundations of asset pricing. We note, also, that the CAPM methodology is not the sole candidate for rate-of-return determination in utility rate cases. Morin (2006, p. 13) identifies four main approaches used in the determination of the "fair return to the equity holder of a public utility's common stock," of which the CAPM is but one.[3] Nevertheless, the concept of the appropriate rate of return on equity being a combination of a riskless rate of return and a premium for risk-bearing has since become widely accepted as a means of determining the appropriate authorized return on equity in state-level utility rate cases (Phillips, 1993, pp. 394–400). In contrast, the Federal Energy Regulatory Commission relies exclusively on the DCF approach, which is also common with natural gas utilities. For electric utilities, however, the CAPM in particular is seen as the "preferred" (Myers, 1972; Roll and Ross, 1983, p.22) and "most widely used" (Villadsen et al., 2017, p. 51) method in regulatory proceedings. Multi-factor approaches such as Arbitrage Pricing Theory (APT) (Ross, 1976) and the Fama and French (1993) framework are used with significantly less frequency in practice (Villadsen et al., 2017, p. 206). In other words, our focus on the CAPM is not solely because of its perceived normative status, but also because it is the method most regulators *say they are using*.

In *Hope,* however, the Court also advocated the "end results doctrine," acknowledging that regulatory methods were (legally) immaterial so long as the end result was reasonable to the consumer and investor. In other words, there was no single formula for determining rates. A typical example of the latitude granted by the doctrine is found in Pennsylvania Public Utility Commission (2016, p. 17): "The Commission determines the [return on equity] based on the range of reasonableness from the DCF barometer group data, CAPM data, recent [returns on equity] adjudicated by the Commission, and **informed judgment** [emphasis added]." Rate determination in practice is often not simply a matter of arithmetic; rather, it is an act of judgment performed by regulators. As a result, our investigation examines not just the relation of authorized rates to those implied by the CAPM, but also the potential for that relationship to be influenced by regulator judgment.

Before we turn to the data, however, let us dispense with an alternate formulation of the underlying question. In questioning the size of the premium and why equity returns are so high, one might also ask instead why the riskless rate is so low. Indeed, Mehra and Prescott (1985) ask this very question, before dismissing it on theoretical grounds. We revisit this question in light of recent data and ask whether the premium during the period in question is more a function of riskless rates being forced down by the Federal Reserve's intervention, than of equity premiums increasing (since the manifest intent of quantitative easing was to lower riskless rates).[4] Our historical data, as Section 3 indicates, do not support that hypothesis. The premium growth has persisted since the beginning of our data series in 1980 and has persisted across a variety of monetary and fiscal policy regimes.

3. Regulated electric utility returns on equity, 1980–2018

3.1. Historical authorized return on equity data

The data used in this study were collected and maintained by Regulatory Research Associates (RRA), a unit of S&P Global. The RRA database is comprehensive. It contains every electric utility rate case in the United States since 1980 in which the utility has requested a rate change of at least $5 million or a regulator has authorized a rate change of at least $3 million. Our study comprises the period from 1980 through 2018. Table 2 illustrates the bridge from the RRA rate-case population to the rate-case sample used in our analyses. We examined the returns on equity authorized by the regulatory agencies, *not* the returns requested by the utilities.[5] The sample we use in this paper contains 79% of the RRA universe, but 97% of the rate cases in which a rate of return on equity was authorized by a state regulator.

Nearly all fifty states and Washington D.C. are represented in the data set.[6] Thirty-two electric utility rate cases satisfying the qualifications listed above were filed in the average state over the past thirty-eight years, with the most being filed in Wisconsin (120) and the fewest being filed in Tennessee (3), Alaska (2), and Alabama (1). The frequency of filing in a state does not appear to have any relationship to premium growth. The average risk premium has grown in both the ten states that completed the most rate cases and the ten states that completed the fewest rate cases and has grown at very similar rates (see Fig. 1). In fact, as Fig. 2 illustrates, the general trend across all states is similar.

In the early 1980s there were over 100 rate cases filed each year. By the late 1990s, in the midst of widespread deregulation of the electric power industry, the number of filings reached its lowest point (with six in 1999). Since then, filing frequency has increased to an average of forty-eight per year over the last three years (see Fig. 3). The decline in rate case activity in many instances was the direct result of rate moratoria related to the transition to competitive markets in the late 1990s, as well as to moratorium-like concessions made to regulators related to merger approvals over the last decade. Many of these moratoria will expire over the next two years, suggesting a new increase in rate case activity is likely. Finally, no individual utility had an outsized influence on the sample. One hundred forty-four different companies filed rate cases, but many have since merged or otherwise stopped filing.[7] The average firm filed eleven rate cases in our sample. Within our sample the most frequently-filing entity was PacifiCorp, which filed seventy-three rate cases, or less than 5% of the sample.

3.2. Calculating the regulated equity premium

Regulated equity returns are generally equal to the sum of the riskless rate of return and a premium for risk-bearing. In the CAPM, the premium for risk-bearing is given by $\beta(r_m - r_f)$, where β is the utility's

[3] The other three approaches identified by Morin (2006) are: Risk Premium (which is an attempt to estimate empirically what the CAPM derives theoretically), Discounted Cash Flows (or "DCF," which is a dividend capitalization model), and Comparable Earnings (which is an empirical approach to deriving cost of capital from market comparables based on *Hope*).

[4] This has also been an ongoing issue of contention in recent regulatory proceedings. In Opinion 531-B (Federal Energy Regulatory Commission, March 3, 2015, 150 FERC 61,165), the Federal Energy Regulatory Commission (FERC) found that "anomalous capital market conditions" caused the traditional discount rate determination methods not to satisfy the *Hope* and *Bluefield* requirements (150 FERC 61,165 at 7). But in a related decision only eighteen months later (Federal Energy Regulatory Commission, September 20, 2016, 156 FERC 61,198), FERC acknowledged that expert witnesses disagreed as to whether any market conditions were, in fact, "anomalous" (156 FERC 61,198 at 10).

[5] To be clear, we refer to the rates set by regulators as the "authorized" rates. These may be contrasted with utilities' "requested" rates and also with the "earned" rates of return actually realized by utilities. Regulatory *authorization* of a rate is not a guarantee that a utility will actually *earn* such a rate. We address this issue in further detail in Section 4.5.

[6] Only Nebraska did not have a reported rate case meeting the parameters of the data set. Nebraska is unique in that it is the only state served entirely by consumer-owned entities (e.g., cooperatives, municipal power districts) and therefore absent a profit motive it does not have the same adversarial regulatory system as all other states.

[7] The level of analysis is at the regulated utility level. We recognize that many holding companies have multiple ring-fenced regulated utility subsidiaries.

Table 2
Bridge illustrating how our sample is constructed from the RRA electric utility rate case population data.

Number of cases	Percent of cases	Description
2033	100.0%	All electric utility rate cases 1980–2018 in which utility has requested a rate change of at least $5 million or a regulator has authorized a rate change of at least $3 million.
−19	−0.9%	Rate cases with final adjudication (i.e., fully-litigated or settled) still pending as of December 31, 2018, are excluded
−369	−18.2%	Rate cases with no return on equity determination are excluded
−30	−1.5%	Rate cases with no capital structure determination are excluded
−19	−0.9%	Rate cases with authorized rates lower than the then-prevailing riskless rate are excluded
1596	79.0%	Rate cases used in our analysis

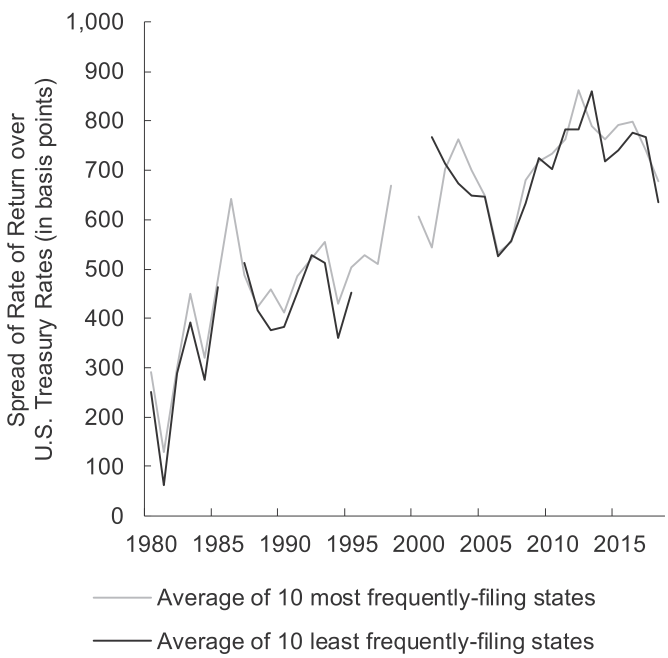


Fig. 1. Risk-premium growth by frequency of case filing. Gaps in the series reflect years in which no rate cases were filed for the subject group. The risk premium is calculated as $r_E - r_f$, or the excess of the authorized return on equity over the then-current riskless rate.

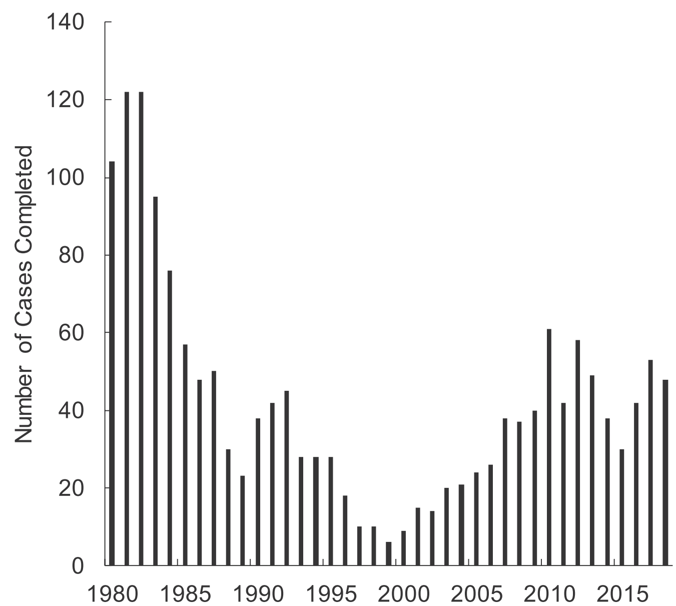


Fig. 3. Number of electric utility rate cases finalized by year.

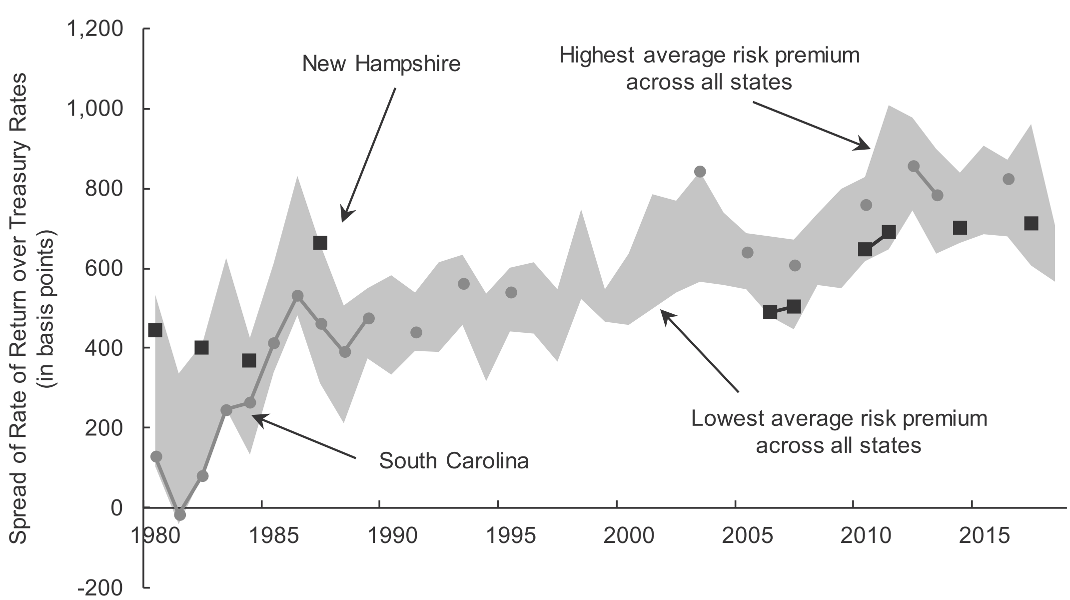


Fig. 2. Range of risk-premium growth across states. States with highest (New Hampshire) and lowest (South Carolina) rates of risk-premium growth over the period (among states with at least five rate cases) are highlighted.

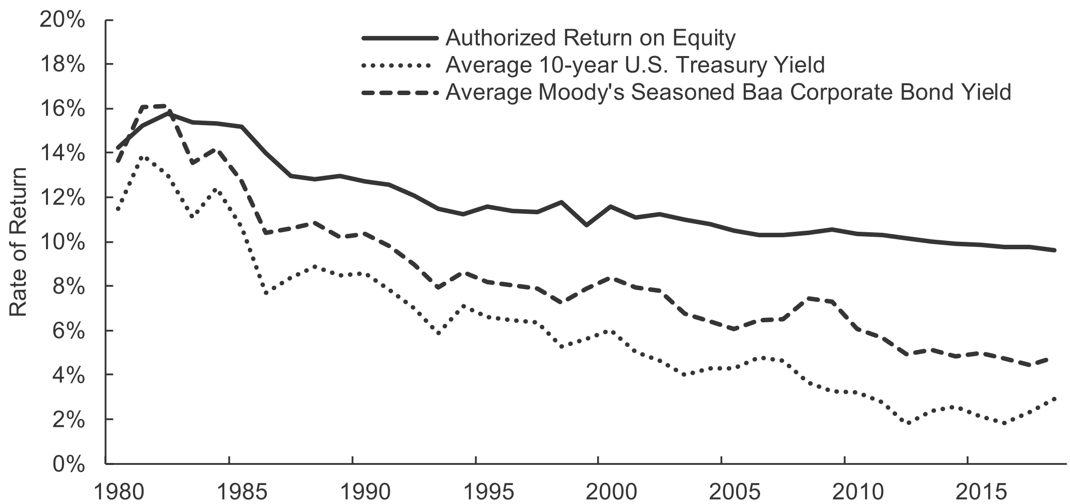


Fig. 4. Annual average authorized return on equity vs. U.S. Treasury and investment grade corporate bond rates.

equity beta. Rearranging the security market line equation [1], we define the regulated equity premium as $r_E - r_f = \beta(r_m - r_f)$. Presented thus, we first note that the existence of a (positive) regulated equity premium is not, by itself, evidence of irrational investor behavior or model failure. Neither is the existence of a growing regulated equity premium. We take no position here on what the "correct" premium should be in any instance. Rather, we shall be content in this article simply to determine whether or not the behavior of the risk premium in practice is consistent with financial theory.

On average, the authorized return on equity is 5.1% (standard deviation = 2.2%) higher than the riskless rate. Fig. 4 illustrates the average authorized return on equity over the period against the average annual riskless rate and investment-grade corporate bond rate.[8] For avoidance of doubt, we note that only the U.S. Treasury note rate should be considered the riskless rate. We include corporate bond rates solely to assess whether the trend in riskless rates is materially different from the trend in risky debt.

While the regulated equity premium has averaged 510 basis points across the entire time period, in 1980 the average premium was only 277 basis points, whereas in 2018 it averaged 668 basis points. Fig. 5 shows the difference between the authorized return on equity and the riskless rate for each case in the data over the past thirty-eight years. Although the premium is determined against the riskless rate of return (represented here as the yield on a 10-year U.S. Treasury note), we also present for comparison the spreads determined against the yield on the Moody's Seasoned Baa Corporate Bond Index to illustrate that the effect is not an artifact of recent monetary policy on Treasury rates. The trends of the two series are quite similar (and both have statistically-significant positive slopes); accordingly, we shall present only the Treasury rate-determined premiums throughout the remainder of this paper.

Given that a large and growing regulated equity premium exists, our question is whether or not it can be explained within an equilibrium asset-pricing framework such as the CAPM. If β were to have increased during the time period in question, for example, the growth of the regulated equity premium may well be explained by the increasing (relative) riskiness of utility equity. As Section 4 demonstrates, however, in fact it cannot.

[8] We used the 10-year constant maturity U.S. Treasury note yield as a proxy for the riskless rate and the yield on the Moody's Seasoned Baa Corporate Bond Index as a proxy for investment-grade corporate bond rates. Both series were obtained from the Federal Reserve's FRED database (Board of Governors of the Federal Reserve System, n.d.-a; n.d.-b).

4. Potential explanations for the premium

Having demonstrated the existence of a large and growing regulated equity premium, we investigate various potential explanations. As we indicated above, we proceed with our investigation of explanations for the premium via the Capital Asset Pricing Model. The CAPM allows three basic mechanisms of action for a change in the risk premium: (i) the manner in which the underlying assets are financed has changed, (ii) the risk of the underlying assets themselves has changed, and/or (iii) the rate at which the market in general prices risk has changed. We explore each in turn and formally test whether the trend in the data can be explained by the CAPM. Finding that it cannot, we then turn to theoretical explanations outside of the CAPM. The potential alternative explanations in Sections 4.5 through 4.7 all represent viable paths for further research.

4.1. Capital structure effects

As corporate leverage increases, the underlying equity becomes riskier and thus deserving of higher expected returns. In finance, the Hamada equation decomposes the CAPM equity beta (β) into an underlying asset beta (β_A) and the impact of capital structure (Hamada, 1969, 1972). Specifically, the Hamada equation states that $\beta = \beta_A\left[1 + (1 - \tau)\frac{D}{E}\right]$, where τ is the tax rate and D and E are the debt and equity in the firm's capital structure, respectively. We use the marginal corporate federal income tax rate for the highest bracket, as provided in Internal Revenue Service (n.d.).

One explanation for a growing risk premium would be steadily increasing leverage among regulated utilities. However, regulators also generally approve of specific capital structures as part of the rate-making process. As a result, our database also contains the authorized capital structures for each utility.[9] In fact, utilities are *less* leveraged today than they were in 1980. The average debt-to-equity ratio in the first five years of the data set (1980–1984) was 1.74; in 2014–2018 it was 1.05. More generally, we can observe the impact of leverage

[9] To be clear, the authorized capital structures evaluated here apply to the regulated utility subsidiaries, and not necessarily to any holding companies to which they belong. The holding companies themselves may utilize more or less leverage, but typically the regulated utility subsidiaries are "ring-fenced" so as to isolate them from holding company-level risks. Similarly, rate-of-return regulation would apply only to the regulated subsidiaries, not to the parent holding company. As a result, the capitalization of the regulated entity (studied here) is often different from the capitalization of the publicly-traded entity that owns it.

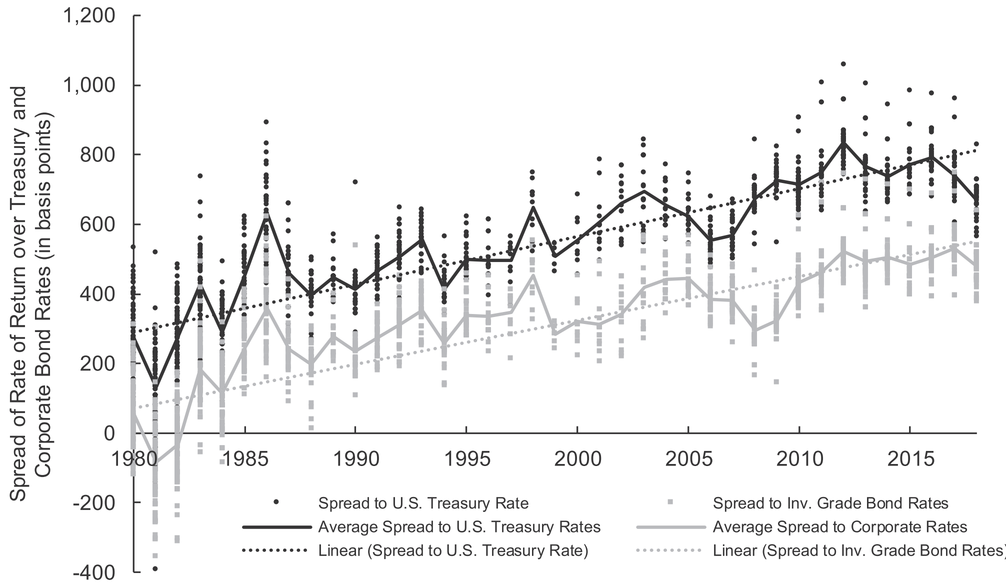


Fig. 5. Authorized return on equity premium, 1980–2018.

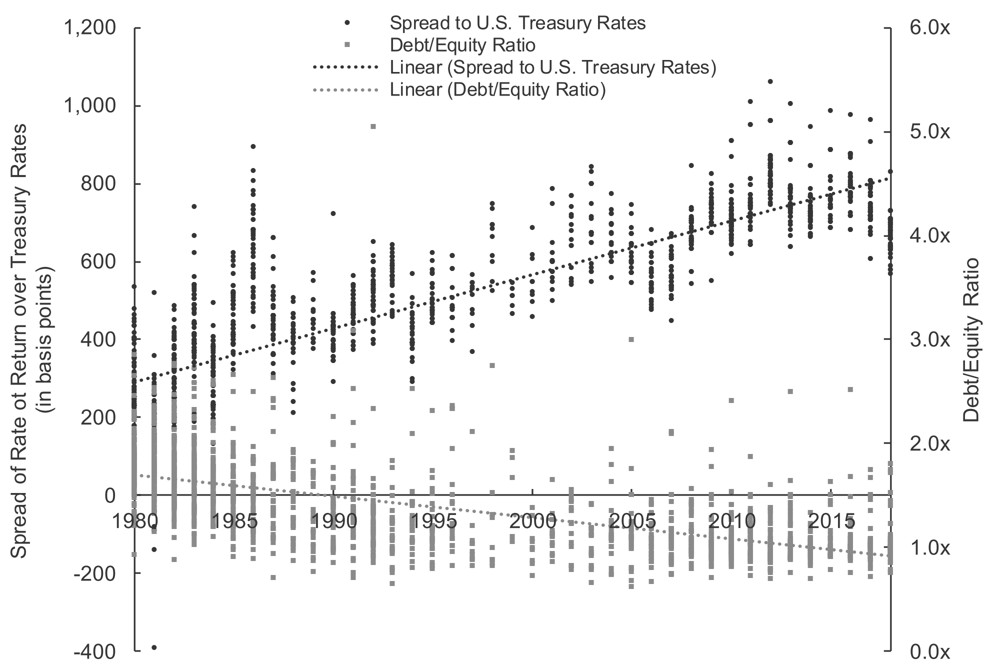


Fig. 6. Authorized return on equity premium vs. utility leverage.

moving in the opposite direction of what one may expect, whether we examine the debt-to-equity ratio exclusively or the Hamada capital structure parameter (i.e., the portion of the Hamada equation multiplied by β_A, or $\left[1 + (1-\tau)\frac{D}{E}\right]$) in its entirety. Figs. 6 and 7 illustrate these results. As a result, it does not appear as if capital structure itself can explain the behavior of the risk premium.

4.2. *Asset-specific risk*

As noted above, the Hamada equation decomposes returns into compensation for bearing asset-specific risks and for bearing capital structure-specific risks. Even if a firm's capital structure remains unchanged, the riskiness of its underlying assets may change. This risk is represented by the unlevered asset beta, β_A. An increase in the asset beta applicable to such investments would, all else held equal, justify an increase in the risk premium.

To examine such a hypothesis, we used the fifteen members of the Dow Jones Utility Average between 1980 and 2018 as a proxy for "utility asset risk." We estimated five-year equity betas for each firm by regression of their monthly total returns against the total return on the S&P 500 index.[10] The equity betas calculated were then converted to

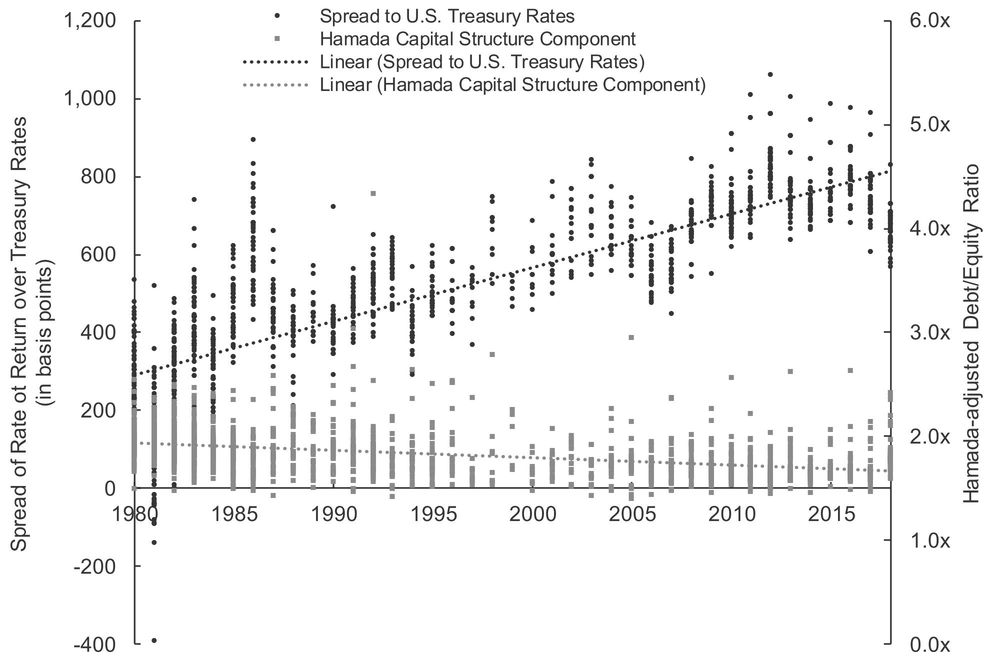


Fig. 7. Authorized return on equity premium vs. the Hamada capital structure parameter.

asset betas using Hamada's equation and corrected for firm cash holdings using firm-specific balance sheet information. We then averaged the fifteen asset betas calculated in each year as our proxy for utility asset risk.[11] The results remain substantively unchanged whether an equal-weighted or a capitalization-weighted average is used.

Although there is, of course, variation in the industry average asset beta across the thirty-eight years, the general trend is down. Fig. 8 presents the risk premium in comparison to the industry average asset beta. As a result, the asset beta is moving in the opposite direction from what one might expect, given a steadily-increasing risk premium, and therefore does not appear to explain the observed behavior of the risk premium.

4.3. The market risk premium

The last CAPM-derived explanation for a changing risk premium relates to the pricing of risk assets in general. If investors require greater compensation for bearing the systematic risk of the market in general, then the risk premium across all assets would increase as well (all else held equal) as a result of the average risk aversion coefficient of investors increasing. The market risk premium reflects this risk-bearing cost in the CAPM.

Although we can observe the *ex post* market risk premium, investors' assessment of the *ex ante* market risk premium is generally based on assuming that historical experience provides a meaningful guide to future experience.[12] It is customary to examine the actual market risk premium over some historical time period and base one's estimate of the *expected* future market risk premium on that historical experience (Sears and Trennepohl, 1993; Villadsen et al., 2017, p. 59). While the size of the historical window is subjective, it is sufficient for our purposes to note that the slope of the market risk premium over time has been negative irrespective of the historical window used.[13] Most sources advocate for using the longest time window available (Villadsen et al., 2017, p. 61); we use a fifty-year historical window for calculation purposes. As Fig. 9 illustrates, that declining trend in the market risk premium appears to be inconsistent with the increasing risk premium exhibited by the rates of return authorized by regulators.

4.4. Testing a theoretical model of the risk premium

Although we have illustrated that each component of the CAPM risk premium appears at odds with the risk premium derived from rates of return authorized by regulators, we now turn to a formal exploration of these relationships. By combining the security market line representation of the CAPM [1] and the Hamada equation, we can define the risk premium, $r_E - r_f$.

$$r_E - r_f = \beta_A \times \left[1 + (1-\tau)\frac{D}{E}\right] \times MRP \tag{2}$$

In [2], $r_E - r_f$ is the risk premium, or the difference between the authorized rate of return on equity for a given firm in a given rate case and the then-prevailing riskless rate. The asset beta, β_A, is calculated as described in Section 4.2. The middle component is taken from the Hamada equation and reflects the marginal corporate income tax rate (τ) in effect in the year in which the equity return was authorized and the authorized debt-to-equity ratio reflected in the regulators' decision for each case. Lastly, *MRP* is the *ex ante* estimate of the market risk

[10] We determined the composition of the Dow Jones Utility Average index at the end of each year and used a rolling five-year window to perform the regressions. For example, the 1980 regression betas were estimated based on monthly returns from 1975 to 1979, the 1981 regression betas were estimated based on monthly returns from 1976 to 1980, and so on.

[11] The balance sheet and total return data are taken from Standard & Poor's COMPUSTAT database. We calculate $\beta'_A = \beta/\left[1+(1-\tau)\frac{D}{E}\right]$ and $\beta_A = \beta'_A/\left[1-\frac{C}{D+E}\right]$, where C equals the amount of cash and cash equivalents held by each firm and D and E represent, respectively, the debt and equity of each firm. We measure D as the sum of Current Liabilities, Long-Term Debt, and Liabilities–Other in the COMPUSTAT data. Because final firm accounting information was not available for 2018 at the time of writing, we maintained the capital structures calculated using 2017 data.

[12] We do not dwell here on the issue of the "observability" of the market portfolio as it relates to testability of the CAPM. We shall assume that the S&P 500 index is a reasonable proxy for the market portfolio.

[13] The market risk premium data used here are taken from data on the S&P 500 and 10-year U.S. Treasury notes collected from the Federal Reserve (Damodaran, n.d.).

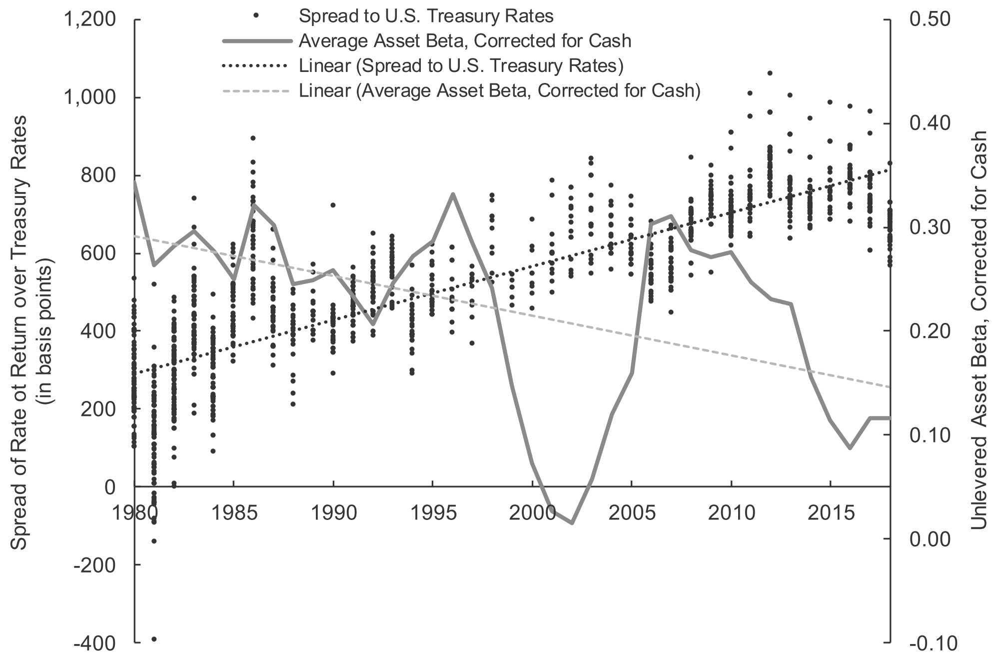


Fig. 8. Authorized return on equity premium vs. industry average asset beta.

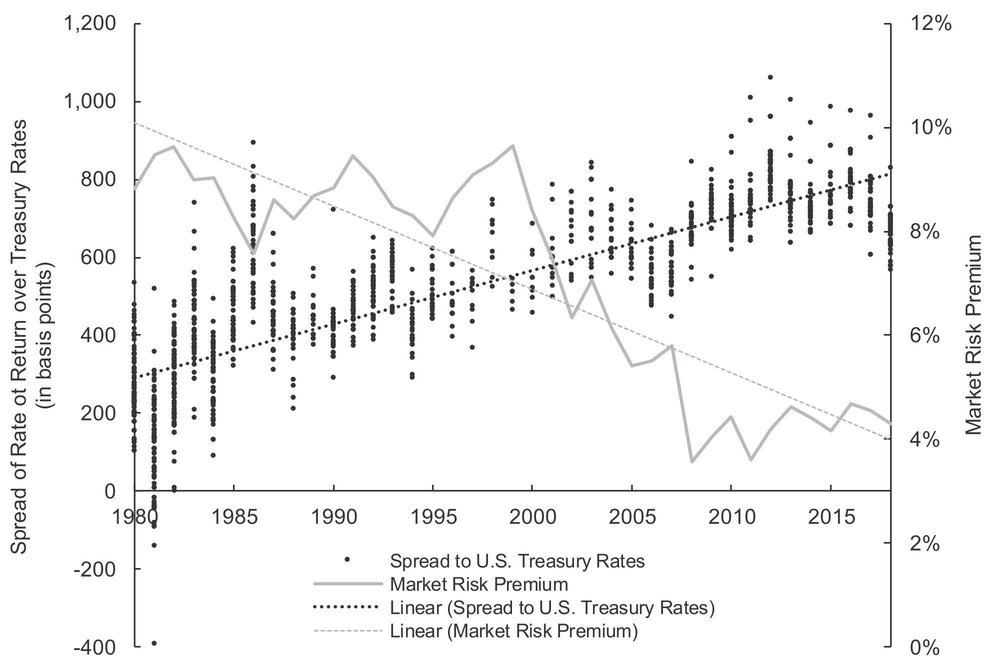


Fig. 9. Authorized rate-of-return premium vs. *ex ante* estimated market risk premium.

premium based on a fifty-year historical window as of the year in which each equity return was authorized.

Let $i = 1, ..., N$ index firms and $t = 1, ..., T$ index years. Not every firm files a rate case in every year. In addition, firms enter and exit over time due to merger or bankruptcy. Because regulators must have an evidentiary record to support their determinations, we assume that each rate case is evaluated independently in an adversarial hearing across time.

By using a logarithmic transform of [2], we arrive at equation [3].

$$ln(r_{E,it} - r_{f,t}) = \gamma_0 + \gamma_1 ln(\beta_{A,t}) + \gamma_2 ln\left[1 + (1 - \tau_t)\frac{D_{it}}{E_{it}}\right] + \gamma_3 ln(MRP_t) \quad (3)$$

In a traditional ordinary least squares (OLS) regression setting, the CAPM would hypothesize that γ_0 should be zero (or not significant) and γ_1, γ_2, and γ_3 should be positive and significant. What we find, however, is exactly the opposite of that (Table 3). The coefficients are negative and strongly significant. Further, a comparison of the observed risk premium to the risk premium estimated by our regression model reveals a good fit (Fig. 10). The negative coefficients are problematic for the CAPM, but also suggest rather counterintuitive effects at an applied

Table 3
Regression results for CAPM-based risk premium model. Coefficients for both the OLS regression model and a model controlling for utility-level fixed effects are shown.

	OLS	Controlling for utility-level fixed effects
	$ln(r_E - r_f)$	$ln(r_E - r_f)$
γ_0, Constant	3.641****	
	(0.130)	
γ_1, Asset beta, $ln(\beta_A)$	−0.158****	−0.156****
	(0.022)	(0.023)
γ_2, Capital structure, $ln\left[1 + (1 - \tau)\frac{D}{E}\right]$	−0.492****	−0.967****
	(0.103)	(0.142)
γ_3, Market risk premium, $ln(MRP)$	−0.947****	−0.898****
	(0.035)	(0.039)
R-squared	46.4%	46.6%
Adjusted R-squared	46.3%	41.2%
F statistic	458.8****	420.9****
No. of observations	1596	1596

Standard errors are reported in parentheses.
*, **, ***, and **** indicate significance at the 90%, 95%, 99%, and 99.9% levels, respectively.

level. Regulators use CAPM prescriptively in rate cases; they are determining what utilities *should* earn. A negative capital structure coefficient suggests, for example, that investors in firms with high leverage *should* be compensated with *lower* returns. Similarly, negative coefficients imply that investors in firms with riskier assets (higher asset betas) and during periods of higher risk aversion (higher market risk premiums) should also be compensated with *lower* returns. These results would be difficult for regulators to justify on normative grounds.

It may be the case, however, that common cross-sectional variation is biasing the results for this data by creating endogeneity issues for the OLS-estimated coefficients. For example, the repeated presence of the same utilities over time could introduce entity-level fixed effects into the analysis. Accordingly, we performed an F-test to evaluate the presence of individual-level effects in the data (Judge et al., 1985: p. 521). The test strongly supports the presence of individual (utility-level) effects ($F_{143,1449} = 1.5$, $p < 0.001$). In addition, the Hausman test (Hausman, 1978; Hausman and Taylor, 1981) supports the fixed-effect specification in lieu of random effects ($\chi^2(3) = 24.0$, $p < 0.001$). As a result, Table 3 also provides the regression coefficients controlling for utility-level fixed effects. These coefficients, while numerically different than the OLS results, are nevertheless still negative and strongly significant, in conflict with both financial theory and regulator intent.

Fig. 10 also reveals a distinct shift in the predicted trend of the risk premium beginning in 1999. This is notable because for many parts of the U.S., 1999 represented the year that implementation of electric market reform and restructuring began, with wholesale markets such as ISO-New England opening and several divestiture transactions of formerly-regulated generating assets occurring, establishing market valuations for formerly regulated assets (Borenstein and Bushnell, 2015). In addition, FERC issued its landmark Order 2000 encouraging the creation of Regional Transmission Organizations. To examine this point in time, we divided the data into two sets, 1980–1998 and 1999–2018, and estimated separate regression models for each subset using both OLS and controlling for utility-level fixed effects (Table 4). As before, the F (pre-1999 $F_{129,805} = 1.6$, $p < 0.001$; post-1998 $F_{129,525} = 3.2$, $p < 0.001$) and Hausman (pre-1999 $\chi^2(3) = 15.5$, $p < 0.01$; post-1998 $\chi^2(3) = 23.8$, $p < 0.001$) tests both strongly support the model controlling for utility-level fixed effects over OLS.

Although the results in both cases are consistent with our earlier finding that the standard finance model appears at odds with the empirical data, the two regression models are noticeably different from one another and appear to better represent the data (Fig. 11). We performed the Chow (1960) test and confirmed the presence of a structural break in the data in 1999 ($F_{4,1588} = 91.6$, $p < 0.001$).[14] We find this result suggestive that deregulatory activity may have an influence even on still-regulated utilities—a point to which we shall return in Section 5.2.

4.5. Potential finance explanations other than the CAPM

In Mehra and Prescott's (2003) review of the equity premium puzzle literature, the authors acknowledge that uncertainty about changes in the prevailing tax and regulatory regimes may explain the premium. Such forces may also be at work with regard to regulated rates of return. To the extent that investors require higher current rates of return because they are concerned about future shocks to the tax or regulatory structure of investments in regulated electric utilities (e.g., EPA's promulgation of the Clean Power Plan, the U.S. Supreme Court's stay of the Clean Power Plan, expiration of tax credits), such concern may be manifest in a higher degree of risk aversion that is unique to investors in the electric utility sector, and therefore a higher "market" risk premium on the assumption that capital markets are segmented for electric utilities.

A separate line of inquiry concerns a criticism of the Hamada equation in the presence of risky debt (Hamada (1972) excluded default from consideration). Conine (1980) extended the Hamada equation to accommodate risky debt by applying a debt beta. Subsequently, Cohen (2008) sought to extend the Hamada equation by adjusting the debt-to-equity parameter to incorporate risky debt in the calculation of the equity beta [4].

$$\beta = \beta_A\left[1 + (1 - \tau)\frac{r_D}{r_f}\frac{D}{E}\right] \tag{4}$$

We view neither of these proposed solutions as entirely satisfying, and note that they tend to be material only for high leverage, which is not common to regulated utilities. Nevertheless, we acknowledge that adjustments to the capital structure may influence the risk premium. However, applying the Cohen (2008) modification and using the Moody's Seasoned Baa Corporate Bond Yield as a proxy for the cost of risky debt (r_D), we note that our regression results are substantively unchanged. As Table 5 illustrates, use of the Cohen betas still results in highly significant, but negative coefficients, which is contrary to theory. These results are maintained when controlling for utility-level fixed effects, and the F (Hamada $F_{143,1449} = 1.5$, $p < 0.001$; Cohen $F_{143,1449} = 1.3$, $p < 0.01$) and Hausman (Hamada $\chi^2(3) = 24.0$, $p < 0.001$; Cohen $\chi^2(3) = 6.3$, $p < 0.1$) tests are significant in support of the fixed effects model.

In lieu of modifying the CAPM parameters, some researchers have suggested that Ross's (1976) Arbitrage Pricing Theory (APT) is preferable to the CAPM because the CAPM produces a "shortfall" in estimated returns (Roll and Ross, 1983) and "underestimates" actual returns in utility settings (Pettway and Jordan, 1987). While the works of these authors are suggestively similar to the analysis contained in this paper, we note that those authors were examining the *actual* returns on utility common stocks, rather than the rates of return *authorized* by regulators for assets held in utility rate bases. The distinction is important. In the case of the former, it is a question of asset pricing models and efficient capital markets. In the case of the latter, it is an issue of regulator judgment. We note specifically that regulators are making decisions that set these rates, and in many cases are doing so explicitly stating that they are relying in whole or in part on the CAPM. Our question concerns not just whether the CAPM is a better asset pricing model (than the APT, for example), but whether regulators' own judgment can

[14] Additional testing using the Andrews (1993) approach supports the presence of structural breaks during the transitional regulatory period identified by Borenstein and Bushnell (2015), confirming the appropriateness of our selection of 1999 as a year with strong historical motivation for a structural break.

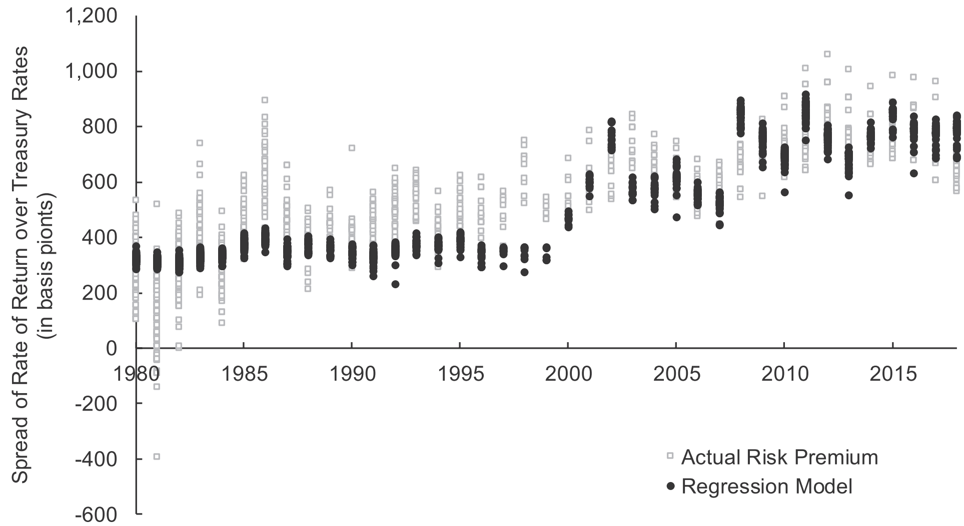


Fig. 10. Actual vs. OLS regression-model risk premium.

Table 4
Regression results for a two-period CAPM-based risk premium model. For purposes of the Chow test, the combined sum of squared residuals was 272.5. Coefficients for both the OLS regression model and a model controlling for utility-level fixed effects are shown.

	OLS		Controlling for utility-level fixed effects	
	1980–1998	1999–2018	1980–1998	1999–2018
	$ln(r_E - r_f)$	$ln(r_E - r_f)$	$ln(r_E - r_f)$	$ln(r_E - r_f)$
γ_0, Constant	−6.259****	5.159****		
	(0.718)	(0.093)		
γ_1, Asset beta, $ln(\beta_A)$	−0.940****	−0.071****	−0.972****	−0.065****
	(0.131)	(0.008)	(0.135)	(0.008)
γ_2, Capital structure, $ln\left[1+(1-\tau)\frac{D}{E}\right]$	−0.140	−0.325****	−0.865****	−0.636****
	(0.150)	(0.049)	(0.224)	(0.075)
γ_3, Market risk premium, $ln(MRP)$	−4.529****	−0.471****	−4.326****	−0.432****
	(0.261)	(0.026)	(0.267)	(0.025)
R-squared	26.7%	36.9%	30.2%	44.9%
Adjusted R-squared	26.4%	36.6%	18.8%	31.0%
F statistic	113.3****	127.3****	116.0****	142.5****
Sum of squared residuals	214.4	8.4	170.8	4.7
No. of observations	938	658	938	658

Standard errors are reported in parentheses.
*, **, ***, and **** indicate significance at the 90%, 95%, 99%, and 99.9% levels, respectively.

be explained by the model on which they claim to rely.

Lastly, to address a related point, we also examined the actual earned rates of return on equity for the 15 utilities in the Dow Jones Utility Average over our historical window. We used each firm's actual return on equity, calculated annually as Net Income divided by Total Equity, as reported in the COMPUSTAT database. This measure of firm profitability examines how successful the firms were at converting their *authorized* returns into *earned* returns. In general, the earned returns closely tracked the authorized returns, suggesting that the decisions of regulators are significantly influencing the actual earnings of regulated utilities. Fig. 12 compares the spread of *authorized* rates of return over riskless rates to the spread of *earned* rates of return over riskless rates and to the median net income of utilities in constant 2018 dollars.[15] The steadily increasing risk premium we have identified is present in both series. The series are correlated at 0.77 (authorized vs. earned), 0.59 (authorized vs. median net income), and 0.75 (earned vs. median net income), all of which are significantly greater than zero ($p < 0.001$). Further, the "capture rate" (the percentage of authorized rates actually earned by the utilities) averaged 96% over the entire time period. As a result, we conclude that the trend of increasing risk premiums is not an abstract anomaly occurring in a regulatory vacuum, but rather a direct contributor to the earnings of regulated utilities.

However, these measures of firm performance must be interpreted with caution. The authorized rates of return apply to jurisdictional utilities, while the earned rates of return are calculated based on holding company performance, which in many cases are not strictly equivalent. Further, increasing net income may be due to industry consolidation producing larger firms (with income increasing only proportionally to size), rather than an increase in profitability itself. In fact, the average income-to-sales ratio of the Dow Jones Utility Average members remained remarkably stable across the period of our study,

[15] We used the median earned rate of return over the 15 Dow Jones utilities. The results are substantively equivalent if the average earned rate of return is used but are more volatile due to the impact on earnings of the California energy crisis of 2000–2001 and the collapse of Enron in 2001.

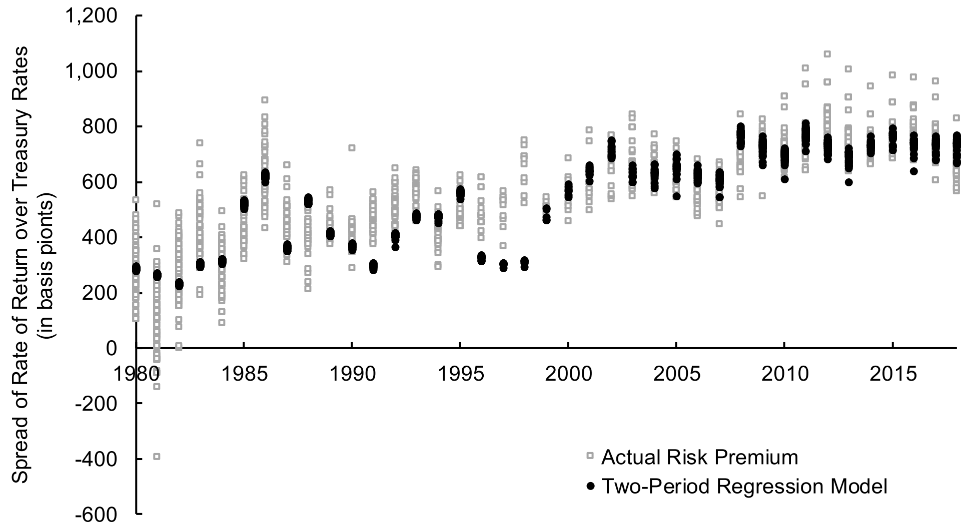


Fig. 11. Actual vs. two-period OLS model-predicted risk premium.

Table 5
Regression results for the standard Hamada capital structure model and Cohen (2008) capital structure model that incorporates risky debt. Coefficients for both the OLS regression model and a model controlling for utility-level fixed effects are shown.

	OLS		Controlling for utility-level fixed effects	
	Hamada $ln(r_E - r_f)$	Cohen $ln(r_E - r_f)$	Hamada $ln(r_E - r_f)$	Cohen $ln(r_E - r_f)$
γ_0, Constant	3.641****	3.191****		
	(0.130)	(0.085)		
γ_1, Asset beta, $ln(\beta_A)$	−0.158****	−0.169****	−0.156****	−0.175****
	(0.022)	(0.022)	(0.023)	(0.023)
γ_2, Capital structure, $ln\left[1 + (1 - \tau)\frac{D}{E}\right]$	−0.492****		−0.967****	
	(0.103)		(0.142)	
γ_2', Capital structure, $ln\left[1 + (1 - \tau)\frac{r_D}{r_f}\frac{D}{E}\right]$		−0.156*		−0.275***
		(0.081)		(0.040)
γ_3, Market risk premium, $ln(MRP)$	−0.947****	−1.046****	−0.898****	−1.087****
	(0.035)	(0.036)	(0.039)	(0.040)
R-squared	46.4%	45.7%	46.6%	45.1%
Adjusted R-squared	46.3%	45.6%	41.2%	39.6%
F statistic	458.8****	447.1****	420.9****	396.9****
No. of observations	1596	1596	1596	1596

Standard errors are reported in parentheses.
*, **, ***, and **** indicate significance at the 90%, 95%, 99%, and 99.9% levels, respectively.

and actually slightly declined, suggesting that gains in net income came from growing revenue, rather than increasing margins (although revenue growth may itself be a function of rising authorized rates of return). Nevertheless, the results are suggestive.

We have not repeated the analysis of Roll and Ross (1983) and Pettway and Jordan (1987) and examined the relationship between firm performance and stock performance. Their findings, however, suggest that regulated utilities have realized *higher* stock returns than can be explained by the CAPM—a finding congruent with our work and suggestive of other factors being priced by the market. This does not entirely explain the judgment issue, however: why regulators appearing to use a CAPM approach provide utilities with returns that also appear to be excessive.

4.6. Potential public choice explanations

Another category of potential explanations emerges from the public choice literature on the role of institutional factors. Regulators may be deliberately or inadvertently providing a “windfall” of sorts to electric utilities. Stigler (1971), among others in the literature on regulatory capture, noted that firms may seek out regulation as a means of protection and self-benefit. This is particularly true when the circumstances are present for a collective action problem (Olson, 1965) of concentrated benefits (excess profits to utilities may be significant) and diffuse costs (the impact of those excess profits on each individual ratepayer may be small). Close relationships between regulators and the industries that they regulate have been observed repeatedly, and one possible explanation for the size and growth of the risk premium is the electric utility industry's increasing “capture” of regulatory power.

We are somewhat skeptical of this explanation, however, both because of the degree of intervention in most utility rate cases by non-utility parties, and because the data do not suggest that regulators have become progressively laxer over time. Fig. 13 compares the rates of return on equity *requested* by utilities in our data set against the rates of return ultimately authorized. As the trend line illustrates, this ratio has remained remarkably stable (within a few percent) over the thirty-eight

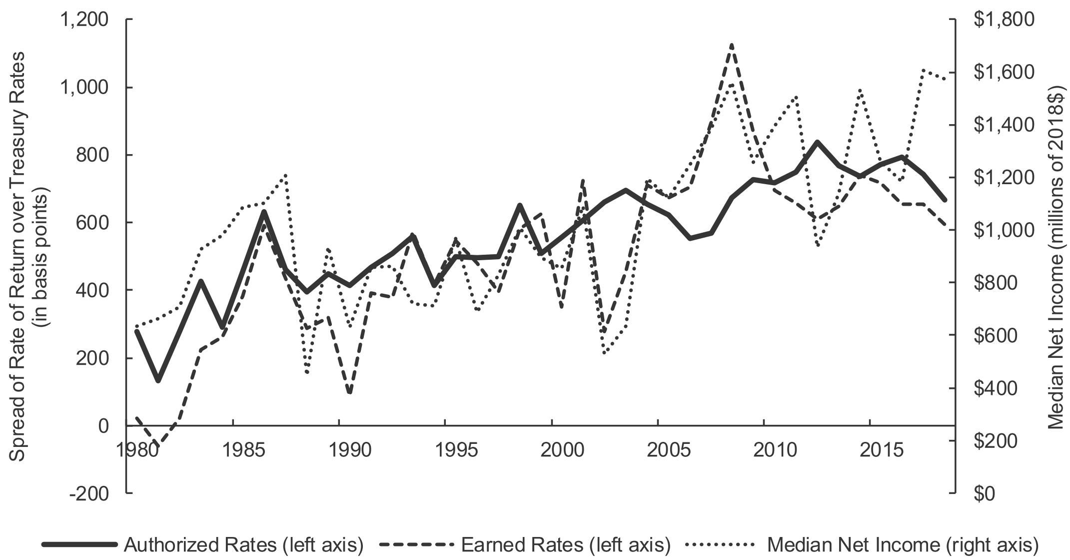


Fig. 12. Comparability of spreads measured with authorized and earned rates of return and utility net income.

years of data, even as the risk premium itself has steadily increased. As a result, the data do not suggest in general an obvious, growing permissiveness on the part of regulators. However, the last nine years are *suggestive* of an increasing level of accommodation among regulators. We propose a possible explanation for this particular pattern in Section 4.7.

To examine the public choice issues further, we investigated whether the risk premiums were related to the selection method of public utility commissioners and whether or not the rate cases in question were settled or fully litigated. The traditional hypothesis has been that elected (instead of appointed) commissioners were less susceptible to capture, more "responsive" to the public, and therefore more pro-consumer. Further, that cases that were settled were more likely to be accommodating to utilities (as money was "left on the table") and therefore would result in higher rates.

A sizable body of literature, however, has largely rejected the selection method hypothesis. Hagerman and Ratchford (1978) and Primeaux and Mann (1986) concluded that the selection method had no impact on returns or electricity prices respectively. Others have agreed that the selection method alone doesn't matter; it is how closely the regulators selected are monitored that matters (Boyes and McDowell, 1989). In addition, whatever evidence of an effect that may exist is likely due to selection method being a proxy for states with different intrinsic structural conditions (Harris and Navarro, 1983). Lastly, while states with elected utility commissioners (Kwoka, 2002) or commissioners whose appointment by the executive requires approval by the legislature (Boyes and McDowell, 1989) tend to have lower electricity prices, those low prices may create the perception of an "unfavorable" investment climate and may therefore lead to a higher cost of capital (Navarro, 1982). Alternatively, if lower prices are observed, it then remains unclear who actually pays (utility shareholders in foregone profits or consumers in higher costs of capital) for the lower observed prices (Besley and Coate, 2003).

To examine the impact of commission selection method and means of case resolution on risk premium, we categorized each state as having an elected or appointed utility commission based on data in Costello (1984), Besley and Coate (2003), and Advanced Energy Economy (2018). In addition, each rate case was reported as being either fully litigated or settled. The literature has hypothesized (but largely not found) that elected commissions are more "responsive" and therefore more pro-consumer. As a result, the expectation would be that the risk premiums implicit in authorized rates were higher for appointed commissions. Similarly, for means of case resolution, risk premiums would be higher for settled, rather than fully litigated rate cases.

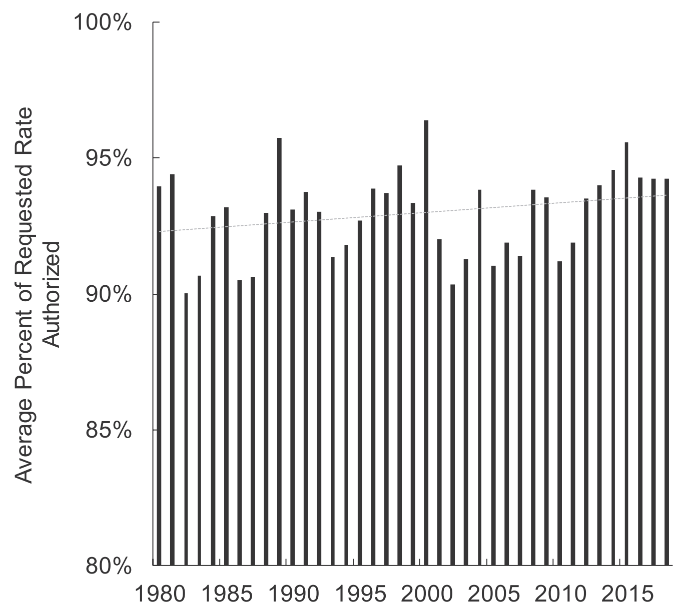


Fig. 13. Rate of return authorized as a percent of rate of return requested.

Table 6
Average risk premium in basis points by commission selection method and means of case resolution. The number of cases in each group is provided in parentheses.

	Appointed Commissions	Elected Commissions	Subtotals
Settled Cases	612 (367)	697 (89)	629 (456)
Fully Litigated Cases	460 (1008)	488 (181)	464 (1189)
Subtotals	500 (1375)	557 (270)	510 (1645)

Like other authors, we found no significant effect *overall* for selection method, but a very significant effect for whether cases were settled or fully litigated. In addition, there appears to be a significant *interaction* between selection method and means of case resolution, suggesting that the lack of evidence of an effect in the literature may be related to its interaction with the means of case resolution, which has not been examined in this depth before. Table 6 illustrates the average risk

Table 7
Regression results for the standard CAPM model and the CAPM model plus two public choice variables (commission selection method and means of case resolution). Coefficients for both the OLS regression model and a model controlling for utility-level fixed effects are shown.

	OLS		Controlling for utility-level fixed effects	
	CAPM $ln(r_E - r_f)$	CAPM + Public Choice $ln(r_E - r_f)$	CAPM $ln(r_E - r_f)$	CAPM + Public Choice $ln(r_E - r_f)$
γ_0, Constant	3.641****	3.519****		
	(0.130)	(0.137)		
γ_1, Asset beta, $ln(\beta_A)$	−0.158****	−0.159****	−0.156****	−0.154****
	(0.022)	(0.022)	(0.023)	(0.023)
γ_2, Capital structure, $ln\left[1+(1-\tau)\frac{D}{E}\right]$	−0.492****	−0.463****	−0.967****	−0.917****
	(0.103)	(0.102)	(0.142)	(0.141)
γ_3, Market risk premium, $ln(MRP)$	−0.947****	−0.927****	−0.898****	−0.858****
	(0.035)	(0.036)	(0.039)	(0.041)
γ_4, Settle = 1		0.223***		0.249****
		(0.057)		(0.060)
γ_5, Appointed = 1		0.159****		0.132**
		(0.034)		(0.058)
γ_6, Settle = 1 × Appointed = 1		−0.182***		−0.197***
		(-0.061)		(-0.065)
R-squared	46.4%	47.4%	46.6%	47.3%
Adjusted R-squared	46.3%	47.2%	41.2%	41.9%
F statistic	458.8****	238.5****	420.9****	216.5****
AIC	−2809	−2810		
No. of observations	1596	1596	1596	1596

Standard errors are reported in parentheses.
*, **, ***, and **** indicate significance at the 90%, 95%, 99%, and 99.9% levels, respectively.

premium observed in each group. The average risk premium for settled cases is significantly higher than for fully litigated cases ($p < 0.001$). Further, while the average risk premium for settled cases and appointed commissions is significantly greater than for fully litigated cases and elected commissions ($p < 0.001$), there is an interaction effect suggesting that the impact of selection method on risk premium depends on the means of case resolution ($p < 0.05$).

Notwithstanding these differences, the incremental explanatory value of these public choice variables is minimal (but significant). Table 7 compares the standard CAPM model with an OLS model that incorporates selection method and means of case resolution. The Akaike Information Criterion (AIC) indicates that incorporation of the public choice variables has only slight incremental value. We estimate that the marginal impact is only approximately 8 basis points—much less than the observed increase over time.[16] As before, the F (CAPM $F_{143,1449} = 1.5$, $p < 0.001$; CAPM + Public Choice $F_{143,1446} = 1.4$, $p < 0.001$) and Hausman (CAPM $\chi^2(3) = 24.0$, $p < 0.001$; CAPM + Public Choice $\chi^2(6) = 24.1$, $p < 0.001$) tests strongly support controlling for utility-level fixed effects in the model. Table 7 also includes coefficients incorporating such controls.

4.7. Potential behavioral economics explanations

To this point, we have examined a number of factors related to economic and institutional influences. At the outset, however, we noted the potential for rate determination to be influenced by regulator judgment. In many cases there is evidence that regulators are not behaving in accordance with the method they in fact purport to be using (i.e., CAPM). As we cannot escape the fact that ultimately the authorized return on equity is a product of regulator decision-making, we now consider possible explanations for the risk premium based on insights from behavioral economics.

First, we note that regulator attachment to rate decisions from the recent past may be coloring their forward-looking decisions. Earlier we referenced a report from Pennsylvania regulators about their stated reliance on (*inter alia*) "recent [returns on equity] adjudicated by the Commission" (Pennsylvania Public Utility Commission, 2016, p. 17). The legal weight attached to precedent may give rise here to a recency bias, where regulators anchor on recent rate decisions and insufficiently adjust them for new information. While stability in regulatory decision-making is seen as useful in assuring investors, to the extent that it results in a slowing of regulatory response when market conditions change, regulators should be encouraged to weigh the benefits of stability against the costs of distortionary responses to authorized returns that lag market conditions.

Our second insight from behavioral economics involves a curious observation in the empirical data: the average rate of return on regulated equity appears to have "converged" to 10% over time. Although the underlying riskless rate has continued to drop, authorized equity returns have generally remained fixed in the neighborhood of 10%, only dropping below (on average) over the last few years. Anecdotally, we have observed a reluctance among potential electric power investors to accept equity returns on power investments of less than 10%—even though those same investors readily acknowledge that *debt* costs have fallen. To that extent, then, a behavioral bias may be at work.

The finance literature has noted a similar effect related to crossing index threshold points (e.g., every thousand points for the Dow Jones Industrial Average). These focal points, which have no normative import, appear to influence investor behavior. Trading is reduced near major crossings (Donaldson and Kim, 1993; Koedijk and Stork, 1994; Aragon and Dieckmann, 2011), with some asserting that the behavior of investors in clienteles may produce this behavior (Balduzzi et al., 1997). We propose a related theory.

In economics, "money illusion" refers to the misperception of nominal price changes as real price changes (Fisher, 1928). Shafir et al. (1997) proposed that this type of choice anomaly arises from framing effects, in that individuals give improper influence to the nominal representation of a choice due to the convenience and salience of the nominal representation. The experimental results have been upheld in several subsequent studies in the behavioral economics literature (Fehr and Tyran, 2001; Svedsäter et al., 2007).

The effect here may be similar: investors and regulators may conflate "nominal" rates of return (the authorized rates) with the risk

[16] For example, the marginal impact of a settled vs. fully-litigated case would be $exp(3.513 + 0.223) - exp(3.513) = 8.4$ using the OLS coefficients.

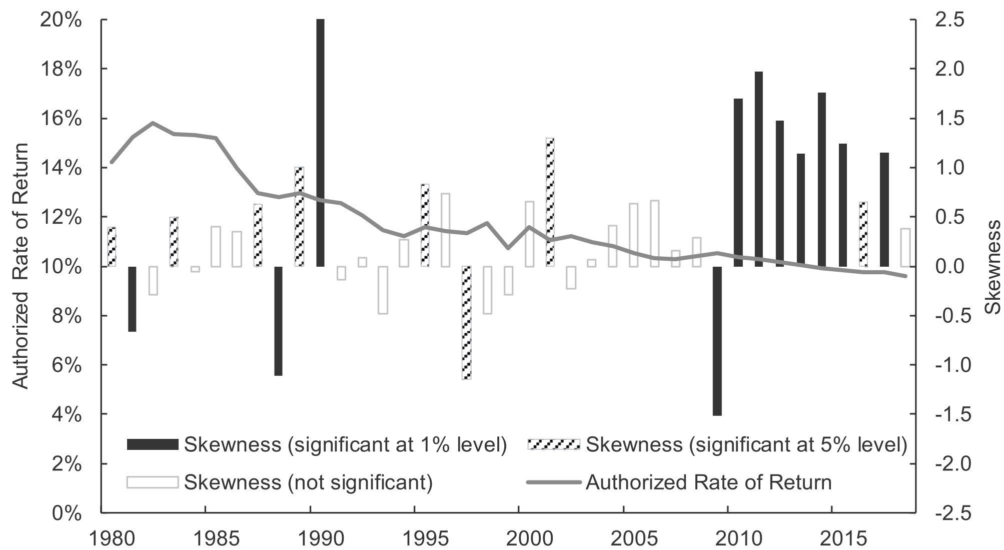


Fig. 14. Authorized rates of return on equity and skewness.

premium underlying the authorized rate. The apparent "stickiness" of rates of return on equity around 10% is similar to the "price stickiness" common in the money illusion (and, indeed, the rate of return is the price of capital). If there was in fact a tendency (intentional or otherwise) to respect a 10% "floor," one might expect that the distribution of authorized returns within each year may "bunch up" in the left tail at 10%, where absent such a floor one may expect them to be distributed symmetrically around a mean. As Fig. 14 illustrates, we see precisely such behavior. As average authorized returns decline to 10% (between 2010 and 2015), the skewness of the within-year distributions of returns becomes persistently and statistically significantly positive, suggesting a longer right-hand tail to the distributions, consistent with a lack of symmetry below the 10% threshold.[17] We note also that this period of statistically significant positive skewness coincides precisely with what appeared to be a period of increased regulator accommodation in Fig. 13. Further, once the threshold is definitively crossed, skewness appears to moderate and the distribution of returns appears to revert toward symmetry.

A related finding has been reported by Fernandez and colleagues (Fernandez et al., 2015, 2017, 2018), where respondents to a large survey of finance and economics professors, analysts, and corporate managers tended, on average, to overestimate the riskless rate of return. In addition, their estimates exhibited substantial positive skew, in that overestimates of the riskless rate far exceed underestimates.[18] The authors found similar results not just in the U.S., but also in Germany, Spain, and the U.K. In the U.S., the average response during the high skewness period exceeded the contemporaneous 10-year U.S. Treasury rate by 20–40 basis points, before declining as skewness moderated in 2018. It may be that overestimating the riskless rate is simply one way for participants in regulatory proceedings to "rationalize" maintaining the authorized return in excess of 10%. Alternatively, it may be an additional bias in the determination of authorized rates of return.

If such biases exist, there are clear implications for the regulatory function itself. For example, this apparent 10% "floor" was even recognized recently in a U.S. Federal Energy Regulatory Commission proceeding (Initial Decision, Martha Coakley, et al. v. Bangor Hydro-Electric Co., et al., 2013, 144 FERC 63,012 at 576): "if [return on equity] is set substantially below 10% for long periods [...], it could negatively impact future investment in the (New England Transmission Owners)." Our findings here draw us back to Joskow's (1972) characterization of regulator decision-making as a sort of meta-analysis. That is, commissioners do not merely directly evaluate the CAPM equations. Rather, they look at the nature of the evidence *as presented to them*. Accordingly, their judgments are based not just on capital market conditions in a vacuum, but on the format, detail, and context of the information contained within the evidentiary record of a rate case. As a result, regulators are susceptible to biases in judgment, and calibration of regulatory decision-making during the rate-setting process should be a required step.

5. Conclusions and policy implications

In this paper, we have examined a database of electric utility rates of return authorized by U.S. state regulatory agencies over a thirty-eight-year period. These rates have demonstrated a growing spread over the riskless rate of return across the time horizon studied. The size and growth of this spread—the risk premium—does not appear to be consistent with classical finance theory, as expressed by the CAPM. In fact, regression analysis of the data suggests the *opposite* of what would be predicted if the CAPM holds. This is particularly perplexing given that regulators often *claim* to be using the CAPM. In addition to the traditional finance factors, our work examined the influence of institutional, structural, and behavioral factors on the determination of authorized rates of return. We find support for many of these factors, although most cannot be justified on traditional normative grounds.

The pattern of large and growing risk premiums illustrated in this paper has significant implications for both utility and infrastructure investment and regulation and market design in environments where both regulated and restructured firms compete for capital. In particular, if rate case activity increases over the next several years as rate moratoria expire, the implications for retail rate escalation and capital investment may be significant. We discuss each in turn before offering some thoughts on possible mitigating factors.

[17] Formally, we test the hypothesis that the observed skewness is equal to zero (a symmetric, normal distribution). The test statistic is equal to the skewness divided by its standard error $\sqrt{6n(n-1)/(n-2)(n+1)(n+3)}$, where n is the sample size. The test statistic has an approximately normal distribution (Cramer and Howitt, 2004).

[18] At the time of the 2015 survey, for example, the 10-year U.S. Treasury rate was 2.0%. The average riskless rate reported by the 1983 U.S. survey respondents was 2.4% (median 2.3%), but responses ranged from 0.0% to 8.0%.

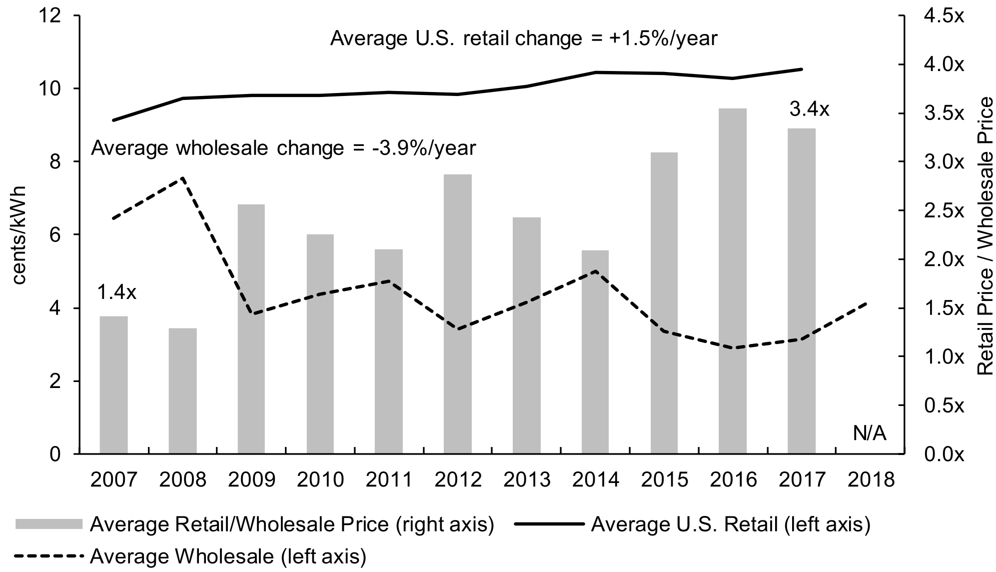


Fig. 15. Peak wholesale (2007–2018) vs. retail (2007–2017) power prices. Wholesale prices represent the average annual peak electricity price in MISO-IN, ISO-NE Mass Hub, Mid-C, Palo Verde, PJM-West, SP-15, and ERCOT-North. Retail prices collected from U.S. Energy Information Administration (https://www.eia.gov/electricity/data/state/avgprice_annual.xlsx). The retail price is the average for the entire country (using only the 7 states with wholesale markets included does not change the result).

5.1. *Wholesale and retail electricity price divergence*

A growing divergence has emerged over the last decade. Although fuel costs and wholesale power prices have declined since 2007, the *retail* price of power has increased over the same period (see Fig. 15). One explanation for this divergence in wholesale and retail rates may be the presence of a growing premium attached to regulated equity returns and therefore embedded into rates. To be sure, other forces may also be at work (for example, recovery of transmission and distribution system investments is consuming a greater portion of retail bills—a circumstance potentially exacerbated by excessive risk premiums). Further, even if the growing divergence between wholesale and retail rates is related to a growing risk premium, it does not necessarily follow that such growth is inappropriate or inconsistent with economic theory. Nevertheless, the potential for embedding of such quasi-fixed costs into the cost structure of electricity production may be significant for end users, as efficiency gains on the wholesale side are more than offset by excess costs of equity capital on the retail side.

5.2. *Regulation itself as a source of risk*

Public policy, or regulation itself, may be a causal factor in the observed behavior of the risk premium. The U.S. Supreme Court acknowledged, in *Duquesne Light Company* et al. *v. David M. Barasch* et al. (488 U.S. 299 (1989), p. 315) that "the risks a utility faces are in large part defined by the rate methodology, because utilities are virtually always public monopolies dealing in an essential service, and so relatively immune to the usual market risks." The recognition that the very act of regulating utilities subjects them to a unique class of risks may influence their cost of capital determination. And yet, if the *purpose* (or at least *a* purpose) of regulating electric utilities is to prevent these quasi-monopolists from charging excessive prices, but the *practice* of regulating them results in a higher cost of equity capital than might otherwise apply, it calls into question the role of such regulation in the first place.

Similarly, we may also question whether the hybrid regulated and non-regulated nature of the electric power sector in the U.S. plays a role as well. Has deregulation caused risk to "leak" into the regulated world because both regulated and non-regulated firms must compete for the same pool of capital? Has the presence of non-regulated market participants raised the marginal price of capital to all firms? In Section 4.4 we illustrated a shift in the trend of risk premium growth in 1999, as several U.S. markets were switching to deregulation, but further study of this question is needed.

The trajectory of public policy during the entire time period studied has been toward deregulation (beginning before 1980 with Public Utility Regulatory Policy Act, through the Natural Gas Policy Act in the 1980s, and electric industry deregulation in the 1990s) and "today's investments face market, political and regulatory risks, many of which have no historical antecedent that might serve as a starting point for modeling risk." (PJM Interconnection, 2016) The general unobservability of the *ex ante* expected returns on deregulated assets complicates determining if the progressive deregulation of the industry has caused a convergence in regulated and non-regulated returns over that time period. While the data do not suggest that utilities in states that have never undertaken deregulation have meaningfully different risk premiums, there are many ways to evaluate the "degree" of deregulatory activity that could be explored.

Another public policy-related factor could be a change in the nature of the rate base or of rate-making itself. Toward the beginning of our study period, most of the electric utilities were vertically integrated (i.e., in the business of both generation and transmission of power). Over time, generation became increasingly exposed to deregulation, while transmission and distribution of power have tended to remain regulated. To the extent that the portion of the rate base comprised of transmission and distribution assets has increased at the expense of generation assets, it may suggest a shift in the underlying risk profile of the assets being recognized by regulators. We note, for example, that public policy has tended to favor transmission investments with "incentive rates" in recent years in order to address a perceived relative lack of investment in transmission within the electric power sector. Our data, however, reveal the opposite. Based on data since 2000, there have been 172 transmission and distribution-only cases, out of 653 total cases. The average rate of return authorized in the transmission and distribution cases is approximately 60 basis points *lower* than those in vertically-integrated cases from the same period. These have been *state-*

level cases however. We note as deserving of further study that (interstate) electric transmission is regulated by FERC using a well-defined DCF approach instead of CAPM. The impact of having differing regulatory frameworks to set rates for assets that are functionally substantially identical remains an open question.

As for a change in the nature of rate-making itself, we note that the industry has tended to move from cost-of-service rate-making to performance-based ratemaking. If this shift, in an attempt to increase utility operating efficiency, has inadvertently raised the cost of equity capital through the use of incentive rates, it would be important to ascertain if the net cost-benefit balance has been positive. In general, there has been a lack of attention to the impact of regulatory changes on discount rates. The data on authorized returns on equity provides a unique dataset for such investigations.

5.3. Strategies for mitigating the growing premium

Our research does not necessarily imply that the rates of return authorized by regulators are too high, or otherwise necessarily inappropriate for utilities. An evaluation of whether these non-normative factors constitute a legitimate basis of rate of return determination deserves separate study. But if institutional or behavioral factors lead to departures from normative outcomes in setting rates of return on equity, then perhaps like Ulysses and the Sirens, regulators' hands should be "tied to the mast."

One notable jurisdictional difference in regulatory practice is between formulaic and judgment-based approaches to setting the cost of capital. In Canada, for example, formulaic approaches are more prevalent than in the United States (Villadsen and Brown, 2012). California also adjusts returns on equity for variations in bond yields beyond a "dead band," and the performance-based regulatory approaches in Mississippi and Alabama rely on formulaic cost of capital determination (Villadsen et al., 2017).

By pre-committing to a set formula (e.g., government bond rates plus *n* basis points) in lieu of holding adversarial hearings, regulators could minimize the potential for deviation from outcomes consistent with finance theory. Villadsen and Brown (2012) noted, for example, that then-recent rates set by Canadian regulators tended to be lower than those set by U.S. regulators despite nearly equivalent riskless rates of return. An intermediate approach would be to require regulators to calculate and present a formulaic result, but then allow them the discretion to authorize deviations from such a result when circumstances justify such departures. In such cases, regulators could avoid anchoring on past results, and instead anchor on a theoretically-justifiable return, before adjusting for any mitigating factors. If regulator judgment is impaired or subject to bias, then minimizing the influence of judgment by deferring to models may be prudent. In the end, we may observe simply that what regulators *should* do, what regulators *say* they're doing, and what regulators *actually* do may be three very different things.

Conflicts of interest

The authors declare that they have no conflict of interest.

Funding

This research did not receive any specific grant from funding agencies in the public, commercial, or not-for-profit sectors.

Acknowledgements

This paper is based on a portion of the first author's doctoral dissertation. The authors gratefully acknowledge the thoughtful comments and assistance received from Jay Apt, Tony Páez, Thomas Yu, Chad Schafer, participants at the Carnegie Mellon Electricity Industry Center's 2017 Advisory Committee Meeting, and two anonymous reviewers. All responsibility for any errors remains with the authors.

Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.enpol.2019.110891.

References

Advanced Energy Economy, 2018. PowerPortal. https://powersuite.aee.net/portal, Accessed date: 2 January 2019.
Andrews, D., 1993. Tests for parameter instability and structural change with unknown change point. Econometrica 61, 821–856. https://doi.org/10.2307/2951764.
Aragon, G., Dieckmann, S., 2011. Stock market trading activity and returns around milestones. J. Empir. Financ. 18, 570–584. https://doi.org/10.1016/j.jempfin.2011.05.010.
Averch, H., Johnson, L., 1962. Behavior of the firm under regulatory constraint. Am. Econ. Rev. 52, 1052–1069.
Balduzzi, P., Foresi, S., Hait, D., 1997. Price barriers and the dynamics of asset prices in equilibrium. J. Financ. Quant. Anal. 32, 137–159. https://doi.org/10.2307/2331170.
Besley, T., Coate, S., 2003. Elected versus appointed regulators: theory and evidence. J. Eur. Econ. Assoc. 1, 1176–1206. https://doi.org/10.1162/154247603770383424.
Binder, J., Norton, S., 1999. Regulation, profit variability and beta. J. Regul. Econ. 15, 249–265. https://doi.org/10.1023/A:1008078230272.
Board of Governors of the Federal Reserve System (US), n.d.-a. 10-Year Treasury Constant Maturity Rate [DGS10], Retrieved from FRED, Federal Reserve Bank of St. Louis. https://research.stlouisfed.org/fred2/series/DGS10 (accessed 2 January 2019).
Board of Governors of the Federal Reserve System (US), n.d.-b. Moody's Seasoned Baa Corporate Bond Yield [BAA], Retrieved from FRED, Federal Reserve Bank of St. Louis. https://research.stlouisfed.org/fred2/series/BAA (accessed 2 January 2019).
Borenstein, S., Bushnell, J., 2015. The U.S. electricity industry after 20 years of restructuring. Annu. Rev. of Econ. 7, 437–463. https://doi.org/10.1146/annurev-economics-080614-115630.
Boyes, W., McDowell, J., 1989. The selection of public utility commissioners: a reexamination of the importance of institutional setting. Public Choice 61, 1–13. https://doi.org/10.1007/BF00116759.
Chow, G., 1960. Tests of equality between sets of coefficients in two linear regressions. Econometrica 28, 591–605. https://doi.org/10.2307/1910133.
Cohen, R., 2008. Incorporating default risk into Hamada's equation for application to capital structure. Wilmott Mag. March/April 62–68.
Conine Jr., T., 1980. Corporate debt and corporate taxes: an extension. J. Financ. 35, 1033–1037. https://doi.org/10.1111/j.1540-6261.1980.tb03519.x.
Costello, K., 1984. Electing regulators: the case of public utility commissioners. Yale J. Regul. 2, 83–105.
Courville, L., 1974. Regulation and efficiency in the electric utility industry. Bell J. Econ. Manag. Sci. 5, 53–74. https://doi.org/10.2307/3003092.
Cramer, D., Howitt, D., 2004. The SAGE Dictionary of Statistics. SAGE Publications, Thousand Oaks, pp. 159. https://doi.org/10.4135/9780857020123.
Damodaran, A., n.d. Annual Returns on Stock, T-Bonds and T-Bills: 1928-Current. http://pages.stern.nyu.edu/~adamodar/New_Home_Page/datafile/histretSP.html (accessed 2 January 2019).
Donaldson, R., Kim, H., 1993. Price barriers in the Dow Jones industrial average. J. Financ. Quant. Anal. 28, 313–330. https://doi.org/10.2307/2331416.
Fama, E., French, K., 1993. Common risk factors in the returns on stocks and bonds. J. Financ. Econ. 33, 3–56. https://doi.org/10.1016/0304-405X(93)90023-5.
Fehr, E., Tyran, J., 2001. Does money illusion matter? Am. Econ. Rev. 91, 1239–1262. https://doi.org/10.1257/aer.91.5.1239.
Fernandez, P., Ortiz, A., Acín, I., 2015. Discount Rate (Risk-free Rate and Market Risk Premium) Used for 41 Countries in 2015: A Survey. http://ssrn.com/abstract=2598104, Accessed date: 2 January 2019.
Fernandez, P., Pershin, V., Acín, I., 2017. Discount Rate (Risk-free Rate and Market Risk Premium) Used for 41 Countries in 2017: A Survey. http://ssrn.com/abstract=2954142, Accessed date: 2 January 2019.
Fernandez, P., Pershin, V., Acín, I., 2018. Market Risk Premium and Risk-free Rate Used for 59 Countries in 2018: A Survey. http://ssrn.com/abstract=3155709, Accessed date: 2 January 2019.
Fisher, I., 1928. The Money Illusion. Adelphi, New York.
Hagerman, R., Ratchford, B., 1978. Some determinants of allowed rates of return on equity to electric utilities. Bell J. Econ. 9, 46–55. https://doi.org/10.2307/3003611.
Hamada, R., 1969. Portfolio analysis, market equilibrium and corporation finance. J. Financ. 24, 13–31. https://doi.org/10.1111/j.1540-6261.1969.tb00339.x.
Hamada, R., 1972. The effect of the firm's capital structure on the systematic risk of common stocks. J. Financ. 27, 435–452. https://doi.org/10.1111/j.1540-6261.1972.tb00971.x.
Harris, M., Navarro, P., 1983. Does electing public utility commissioners bring lower electric rates? Public Util. Fortn. 112, 23–27.
Haug, T., Wieshammer, L., 2019. Cost of equity for regulated networks: recent developments in continental Europe. Electr. J. 32, 1–3. https://doi.org/10.1016/j.tej.2019.02.001.
Hausman, J., 1978. Specification tests in econometrics. Econometrica 46, 1251–1272. https://doi.org/10.2307/1913827.
Hausman, J., Taylor, W., 1981. Panel data and unobservable individual effects.

Econometrica 49, 1377–1398. https://doi.org/10.2307/1911406.
Internal Revenue Service, n.d. SOI Tax Stats, Historical Table 24. https://www.irs.gov/pub/irs-soi/histabb.xls (accessed 2 January 2019).
Joskow, P., 1974. Inflation and environmental concern: structural change in the process of public utility price regulation. J. Law Econ. 17, 291–327. https://doi.org/10.1086/466794.
Hayashi, P., Trapani, J., 1976. Rate of return regulation and the regulated firm's choice of capital-labor ratio: further empirical evidence on the Averch-Johnson model. South. Econ. J. 42, 384–398.
Joskow, P., 1972. The determination of the allowed rate of return in a formal regulatory hearing. Bell J. Econ. Manag. Sci. 3, 632–644. https://doi.org/10.2307/3003042.
Judge, G., Griffiths, W., Hill, R., Lütkepohl, H., Lee, T., 1985. The Theory and Practice of Econometrics, second ed. John Wiley, New York.
Koedijk, K., Stork, P., 1994. Should we care? Psychological barriers in stock markets. Econ. Lett. 44, 427–432. https://doi.org/10.1016/0165-1765(94)90116-3.
Kwoka, J., 2002. Governance alternatives and pricing in the U.S. electric power industry. J. Law Econ. Organ. 18, 278–294. https://doi.org/10.1093/jleo/18.1.278.
Lintner, J., 1965. Security prices, risk, and maximal gains from diversification. J. Financ. 20, 79–96. https://doi.org/10.1111/j.1540-6261.1965.tb02930.x.
Mehra, R., Prescott, E., 1985. The equity premium: a puzzle. J. Monet. Econ. 15, 145–161. https://doi.org/10.1016/0304-3932(85)90061-3.
Mehra, R., Prescott, E., 2003. The equity premium in retrospect. In: Constantinides, G., Harris, M., Stulz, R. (Eds.), Handbook of the Economics of Finance. Elsevier, Amsterdam, pp. 889–938.
Morin, R., 2006. New Regulatory Finance. Public Utilities Reports, Vienna.
Mossin, J., 1966. Equilibrium in a capital asset market. Econometrica 34, 768–783. https://doi.org/10.2307/1910098.
Myers, S., 1972. The application of finance theory to public utility rate cases. Bell J. Econ. Manag. Sci. 3, 58–97. https://doi.org/10.2307/3003071.
Navarro, P., 1982. Public utility commission regulation: performance, determinants, and energy policy impacts. Energy J. 3, 119–139. https://doi.org/10.5547/ISSN0195-6574-EJ-Vol3-No2-7.
Olson, M., 1965. The Logic of Collective Action. Harvard University Press, Cambridge.
Pennsylvania Public Utility Commission, 2016. Bureau of Technical Utility Services Report on the Quarterly Earnings of Jurisdictional Utilities for the Year Ended June 30, 2016. Docket M-2016-2570997. . http://www.puc.state.pa.us/pcdocs/1483248.docx, Accessed date: 2 January 2019.
Pettway, R., Jordan, B., 1987. APT vs. CAPM estimates of the return-generating function parameters for regulated public utilities. J. Financ. Res. 10, 227–238. https://doi.org/10.1111/j.1475-6803.1987.tb00493.x.
Phillips Jr., C., 1993. The Regulation of Public Utilities. Public Utilities Reports, Arlington.
PJM Interconnection, 2016. Resource Investment in Competitive Markets. http://pjm.com/~/media/documents/reports/20160505-resource-investment-in-competitive-markets-paper.ashx, Accessed date: 2 January 2019.
Primeaux, W., Mann, P., 1986. Regulator selection methods and electricity prices. Land Econ. 62, 1–13. https://doi.org/10.2307/3146558.
Roberts, R., Maddala, G., Enholm, G., 1978. Determinants of the requested rate of return and the rate of return granted in a formal regulatory process. Bell J. Econ. 9, 611–621. https://doi.org/10.2307/3003601.
Roll, R., Ross, S., 1983. Regulation, the capital asset pricing model, and the arbitrage pricing model. Public Util. Fortn., May 26 (1983), 22–28.
Ross, S., 1976. The arbitrage theory of capital asset pricing. J. Econ. Theory 13, 341–360. https://doi.org/10.1016/0022-0531(76)90046-6.
Sears, R., Trennepohl, G., 1993. Investment Management. Dryden Press, Ft. Worth, pp. 516–517.
Shafir, E., Diamond, P., Tversky, A., 1997. Money illusion. Q. J. Econ. 112, 341–374. https://doi.org/10.1162/003355397555208.
Sharpe, W., 1964. Capital asset prices: a theory of market equilibrium under conditions of risk. J. Financ. 19, 425–442. https://doi.org/10.1111/j.1540-6261.1964.tb02865.x.
Spann, R., 1974. Rate of return regulation and efficiency in production: an empirical test of the Averch-Johnson thesis. Bell J. Econ. Manag. Sci. 5, 38–52. https://doi.org/10.2307/3003091.
Stigler, G., 1971. The theory of economic regulation. Bell J. Econ. Manag. Sci. 2, 3–21. https://doi.org/10.2307/3003160.
Svedsäter, H., Gamble, A., Gärling, T., 2007. Money illusion in intuitive financial judgments: influences of nominal representation of share prices. J. Socio Econ. 36, 698–712. https://doi.org/10.1016/j.socec.2007.01.006.
Villadsen, B., Brown, T., 2012. International innovations in rate of return determination. In: Presentation at the 2012 Society of Utility and Regulatory Financial Analysts Forum, April 26, 2012.
Villadsen, B., Vilbert, M., Harris, D., Kolbe, A.L., 2017. Risk and Return for Regulated Industries. Academic Press, Cambridge.
Vitaliano, D., Stella, G., 2009. A frontier approach to testing the Averch-Johnson hypothesis. Int. J. Econ. Bus. 16, 347–363. https://doi.org/10.1080/13571510903227031.