Exhibit No.:	MAWC 29
Issues:	Staff Rate Design Analysis
Witness:	Scott W. Rungren
Exhibit Type:	Supplemental
Sponsoring Party:	Missouri-American Water Company
Case No.:	WR-2015-0301
	SR-2015-0302
Date:	February 10, 2016

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. WR-2015-0301
CASE NO. SR-2015-0302

SUPPLEMENTAL TESTIMONY

OF

SCOTT W. RUNGREN

ON BEHALF OF

MISSOURI-AMERICAN WATER COMPANY

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

IN THE MATTER OF MISSOURI-AMERICAN) WATER COMPANY FOR AUTHORITY TO) FILE TARIFFS REFLECTING INCREASED) RATES FOR WATER AND SEWER) SERVICE)	CASE NO. WR-2015-0301 CASE NO. SR-2015-0302

AFFIDAVIT OF SCOTT W. RUNGREN

Scott W. Rungren, being first duly sworn, deposes and says that he is the witness who sponsors the accompanying testimony entitled "Supplemental Direct Testimony of Scott W. Rungren"; that said testimony and schedules were prepared by him and/or under his direction and supervision; that if inquiries were made as to the facts in said testimony and schedules, he would respond as therein set forth; and that the aforesaid testimony and schedules are true and correct to the best of his knowledge.

Scott W. Rungren

Scott W. Rungren

State of Missouri
County of St. Louis
SUBSCRIBED and sworn to
Before me this 9th day of February 2016.

Donna S. Singler

Notary Public

My commission expires: July 17, 2016

DONNA S. SINGLER
Notary Public, Notary Seal
State of Missouri
St. Louis County
Commission # 12368409
My Commission Expires July 17, 2016

SUPPLEMENTAL TESTIMONY
SCOTT W. RUNGREN
MISSOURI-AMERICAN WATER COMPANY
CASE NO. WR-2015-0301
CASE NO. SR-2015-0302

TABLE OF CONTENTS

I. Introduction 1

II. Purpose 1

III. Discussion of Alternative Rate Structures and Impact on Rate Return 2

SUPPLEMENTAL TESTIMONY

SCOTT W. RUNGREN

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Scott W. Rungren. My business address is 727 Craig Road, St. Louis, Missouri 63141.

Q. DID YOU PREVIOUSLY SUBMIT PREPARED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, I did.

II. PURPOSE

Q. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL TESTIMONY?

A. In its Order entered on February 3, 2016 in this proceeding, the Missouri Public Service Commission (Commission) directed Missouri-American Water Company (MAWC or the Company) to file Supplemental Testimony addressing seven concepts related to alternative rate structures and "to respond to the opinions Staff expressed about those concepts in its analysis" (Order, p. 2). The purpose of my Supplemental Testimony is to address concept number seven (7), which is "a corresponding downward adjustment in Return on Equity." Accordingly, I will address the opinions expressed by Staff on this issue in *Staff's Water Utility Rate Design Analysis* (Staff Report) filed in this rate case.

III. DISCUSSION OF ALTERNATIVE RATE STRUCTURES AND IMPACT ON RATE OF RETURN

Q. WHAT ARE THE SIX RATE STRUCTURE CONCEPTS IDENTIFIED ON PAGE TWO OF THE COMMISSION'S ORDER?

A. They are as follows:

1. An increase to the customer charge;
2. A corresponding decrease in the volumetric charge;
3. Inclining block rates for residential customers;
4. Level rates for commercial and industrial customers;
5. A modified future test year for consumption;
6. A one-way tracker on consumption.

Q. WHAT IS THE IMPACT OF THE ALTERNATIVE RATE MECHANISMS LISTED ABOVE ON MAWC'S COST OF EQUITY?

A. Although he did not specifically address any of the six concepts I list above, this issue was generally addressed by Company witness Dr. Roger Morin in his Direct Testimony in this case. Dr. Morin's conclusion is that the adoption of alternative rate mechanisms, such as a Revenue Stabilization Mechanism (RSM) or Straight-Fixed Variable ("SFV") rate design, would not require any downward adjustment to the Company's allowed return on equity because the companies in his water utility sample (i.e., proxy group), which he used to estimate MAWC's cost of equity, already employ many of the mechanisms noted above. Thus, adjusting MAWC's cost of equity downward in the event some, or all, of these balanced mechanisms were adopted by the Commission would constitute double-counting (Morin DT, pp. 65-66).

Q. WITH THE EXCEPTION OF THE ONE-WAY TRACKER, ARE SOME OR ALL OF THE MECHANISMS BEING USED BY OTHER WATER UTILITY COMPANIES IN THE UNITED STATES?

A. Yes. As explained by Dr. Morin in his Direct Testimony, "the approval of trackers and riders, adjustment clauses, forecast test years and other mechanisms, by regulatory commissions is widespread in the utility business and is already largely embedded in financial data, such as bond ratings, stock prices, and business risk scores." Thus, to the extent the market derived cost of common equity for these companies already incorporates the impacts of these or similar mechanisms, no further adjustment to the cost of common equity is reasonable or appropriate (Morin DT, p. 66).

Q. WHAT IS THE IMPACT OF THESE MECHANISMS INDIVIDUALLY ON THE COMPANY'S COST OF EQUITY?

A. As Dr. Morin noted in his Direct Testimony, rate design approaches that shift cost recovery from the variable rate to the fixed component reduce risk on an absolute basis but not necessarily on a relative basis, that is, relative to other utilities. Thus, while factors such as SFV rate design, RSM, future test periods, and infrastructure surcharge mechanisms tend to reduce risk, no adjustment to the cost of equity is necessary because the financial data of the proxy companies used in cost of equity analyses already reflects any risk-reducing impacts of the mechanisms. Further, the Company is not aware of any studies that have quantified, in terms of a basis point adjustment, the extent to which any of the six rate concepts impact a utility's cost of equity.

Q. PLEASE COMMENT ON THE STAFF OPINION WITH RESPECT TO WHETHER THE ALLOWED ROE SHOULD BE ADJUSTED IF COST RECOVERY IS SHIFTED FROM THE VARIABLE RATE COMPONENT TO THE FIXED RATE COMPONENT, OR CUSTOMER CHARGE.

A. The Staff Report stated that Staff was unable to provide a "definitive recommendation of how a restructured water rate design should be considered for purposes of setting an allowed ROE for water utilities" (Staff Report, p. 10 – unnumbered). The general reason for Staff's conclusion is the lack of research on this issue as it relates to water utilities. Staff also noted that it was unable to determine whether any of American Water Company's other operating subsidiaries had a rate design similar to that analyzed in the Staff Report. I concur with the Staff's view that there is currently a lack of test cases for quantifying the impact of a SFV rate design on a water utility's cost of equity. This should not lead Staff to conclude, however, that adoption of a SFV rate design would warrant a downward adjustment to the cost of equity for ratemaking purposes. While the impact of a SFV rate structure may be to reduce risk, no adjustment to the cost of equity would be necessary because water utilities are, to a large extent, using various mechanisms that enhance their ability to recover fixed costs. Thus, while SFV rate designs may be uncommon, or non-existent in the water industry, other mechanisms have achieved the same or a similar end result that a SFV rate design would provide. The Commission should continue to look to the capital markets to inform them of a utility's cost of capital and evaluate the impact of a

Revenue Stabilization Mechanism in the utility's subsequent rate case using a comparison group of utilities.

Q. PLEASE DISCUSS THE OTHER MECHANISMS IMPLEMENTED BY AMERICAN WATER AND OTHER WATER UTILITIES THAT HAVE REDUCED THE UNCERTAINTY OF FIXED COST RECOVERY.

A. Although there has not been any significant movement to SFV rate designs by American Water's subsidiaries or, as far as I am aware, other regulated water utilities, most water utilities, including American Water's subsidiaries, have implemented alternative rate mechanisms and employ other tools to increase the recovery of fixed costs and reduce regulatory lag. These have been summarized in Exhibit RAM-8, attached to the Direct Testimony of Roger Morin in this case and attached hereto as Schedule SWR-2. It shows that many of American Water's subsidiaries, as well as other regulated water utilities, have mechanisms in place for items such as infrastructure investment (ISRS), pension and other post-retirement benefits (OPEBs), power and chemicals, purchased water, and environmental or safety costs. Most of the water companies listed are also able to use a future test year for ratemaking purposes. Many of these mechanisms improve a utility's ability to recover its fixed and variable costs. Due to the prevalence of these alternative rate mechanisms in the water utility industry, no downward adjustment to the allowed return on equity is necessary or appropriate.

Q. ARE YOU AWARE OF ANY STUDIES DEALING WITH THE IMPACT OF ALTERNATIVE RATEMAKING APPROACHES ON A UTILITY'S COST OF EQUITY?

A. Yes, I am. The Brattle Group published a study in March 2011 entitled "The Impact of Decoupling on the Cost of Capital: An Empirical Investigation". The study concluded that any impact from decoupling on the cost of capital "must be minimal because it is not detectable statistically" (Brattle Study, p. 14). This study is attached to this testimony as Schedule SWR-3. The Brattle Group released a similar study on March 20, 2014 entitled "The Impact of Revenue Decoupling on the Cost of Capital for Electric Utilities: An Empirical Investigation." The findings of this study were similar to those of their 2011 study, concluding on page 18 that "there is no statistically significant evidence of a decrease in the cost of capital following adoption of decoupling."

Q. YOU HAVE DRAWN A DISTINCTION BETWEEN THE FIRST FIVE RATE STRUCTURE CONCEPTS AND THE SIX CONCEPT, WHICH IS STAFF'S PROPOSED ONE-WAY TRACKER ON CONSUMPTION. PLEASE EXPLAIN THIS DISTINCTION.

A. A one-way tracker on consumption - really revenue - would upend and distort the ratemaking calculus that has been accepted for over a century. Regulatory commissions set rates based on their best forecast of the conditions expected to exist when rates become effective. If those conditions change, that is, if expenses are lower or higher than expected, if investment is more or less than expected, or revenue is lower or higher than expected, the utility and its ratepayers accept such outcomes until rates are eventually changed, whether through a utility filing for an increase or the regulator seeking a decrease. In some cases, symmetrical adjustment clauses are permitted for volatile expenses (e.g., fuel) and revenue (revenue decoupling mechanisms). In none of these instances, however, is the adjustment clause a one-way street where the utility must give back higher-than-projected revenue but absorb the earnings erosion attendant with lower-than-projected revenue. The essence of the one-way tracker is that the utility will never win and can only lose. Investors, who are well aware of regulatory policy through analyst reports, would be very cognizant of such a "head's I win - tails you lose" approach. Such an approach would be viewed negatively and considered a very unsupportive regulatory policy.

Q. DOES THIS CONCLUDE YOUR SUPPLEMENTAL TESTIMONY?

A. Yes, it does.

Schedule SWR-2

State / Company	Decoupling Mechanism (RAC / WRAM)	Capital Investment DSIC, QIP or Equivalent	Pensions and/or OPEB's	Power or Power & Chemicals	Purchased Water or Water & Sewer	Public Health or Safety or Environmental	Conservation Programs	Future Test Year Utilized
	Rate Recovery Mechanisms Applicable to Dr. Morin's Proxy Companies							
American Water Works:								
New York American (LIWC)	Yes	Yes	Yes	Yes[1]				Yes
New Jersey American		Yes			Yes			Yes
Pennsylvania American		Yes						Yes
Virginia American					Yes			Yes
West Virginia American		Note (2)						Yes
Maryland American					Yes			
Tennessee American		Note (4)		Note (4)	Note (4)	Note (4)		Yes
Kentucky American								Yes
Indiana American		Yes						Yes
Illinois American		Yes			Yes			Yes
Iowa American								
Missouri American		Yes	Yes			Yes		
California American	Yes	No	Yes	Yes[3]	Yes[3]	Yes	Yes	Yes
Aqua America:								
Aqua Florida					Yes			Yes
Aqua Illinois		Yes			Yes			Yes
Aqua Indiana		Yes			Yes			Yes
Aqua New Jersey		Yes			Yes	Yes		Yes
Aqua North Carolina		Yes			Yes			
Aqua Ohio		Yes			Yes			Yes
Aqua Pennsylvania		Yes	OPEBs			Yes		Yes
Aqua Texas								
Aqua Virginia								Yes
Others:								
Amer. States Water (Golden State W.C.)	Yes		Yes	Yes[3]	Yes[3]	Yes	Yes	Yes
California Water Service	Yes		Yes	Yes[3]	Yes[3]	Yes	Yes	Yes
San Jose Water Co. (SJW)	Yes		Yes	Yes[3]	Yes[3]	Yes	Yes	Yes
Middlesex Water Co. [7]		Yes			Yes			
Connecticut Water Services [8]	Yes[5]	Yes		Yes[6]	Yes[6]	Yes[6]		
York Water		Yes						Yes

The information provided is based on: (1) Missouri-American's review of the various tariffs of the proxy companies; (2) information provided by the proxy companies, and; (3) other available documentation (e.g., the NAWC Brattle Report).

Footnotes:

(1) Puchased Power and Chemical costs are a sub-reconciliation component of the authorized Revenue Stablization Mechanism.

(2) West Virginia American is allowed post in-service AFUDC (known as AFFAC), which is applied solely to non-revenue-producing replacement utility plant, such as mains, services, etc.

(3) Puchased Power and Purchased Water costs are a sub-reconciliation component of the authorized Revenue Stablization Mechanism.

(4) Tennessee American Water Co. made a filing on 10/4/2013 consistent with new legislation signed by the Tennessee Governor on 4/19/13 authorizing TRA to implement "alternative regulatory methods" for review & recovery of operating expenses, capital costs, or both if such costs are in the public interest and related to: safety requirements of state/fed government; reliability of system utility plant; weather-related natural disasters; for purposes of economic development; and "other programs that in the public interest". Also, the TRA may authorize a mechanism to allow and permit a more timely adjustment of rates resulting from changes in: essential, non-discretionary exps., such as fuel and power and chemcial expenses. Lastly, a utility may file for an "annual review of its rates" based on the methodology adopted in its most recent base rate case, with an Order issued in 120 days.

(5) On April 1, 2014 Connecticut Water implemented its Water Revenue Adjustment (a Revenue Adjustment Mechanism as authorized by the Connecticut Legislature).

(6) Connecticut law provides for interim rate adjustments for increases greater than 0.5% of Company's operating revenues for 1) purchased water; 2) purchased gas or electricity if suppliers rates have been adjusted; and 3) fees for mandated water quality monitoring.

(7) Data provided for Middlesex Water relates to their New Jersey service territory. Its regulated NJ water & sewer operations provide the overwhelming majority of the Company's revenue.

(8) Data provided for Connecticut Water pertains to their Connecticut service territory, which comprises approximately 75 percent of their customers.

DISCUSSION PAPER

March 2011

The Brattle Group

The Impact of Decoupling on the Cost of Capital

An Empirical Investigation

By Joseph B. Wharton, Michael J. Vilbert, Richard E. Goldberg, and Toby Brown[1]

Contents

Introduction

Section 1:
Volumetric Rates, Decoupling, and the Throughput Disincentive........3

Section 2:
Decoupling and the Cost of Capital........4

Section 3:
An Empirical Test of the Effect of Decoupling on the Cost of Capital........5

Conclusion

The Brattle Group provides consulting and expert testimony in economics, finance, and regulation to corporations, law firms, and governments around the world.

We have offices in Cambridge, Massachusetts; San Francisco, California; and Washington, DC. We also have offices in Brussels, London, and Madrid.

For more information, please visit www.brattle.com.

Introduction

Revenue decoupling (or simply "decoupling") is a form of regulated ratemaking that separates cost recovery from changes in the volume of sales for a regulated utility. It originated as a policy response in the 1980s when utilities were first encouraged to develop energy efficiency (EE) programs, which can significantly reduce the consumption of regulated commodities such as electricity, gas, or water.

Research into the costs and benefits of EE technologies has shown that the long-run savings significantly exceed the costs, and EE programs have the additional benefit of producing no harmful emissions. Recently, more states have begun to adopt long-term goals for EE and designated the utilities as the program administrators. Despite the programs being beneficial and cost effective to society, there is a significant disincentive for the utilities to actively pursue the EE programs unless they are accompanied by some type of revenue decoupling and incentives.

This disincentive begins with the fact that a large share of an electric, gas, or water utility's costs are fixed in the short run and do not vary with the amount of the commodity produced and delivered. Traditional cost-of-service ratemaking collects these "base" revenues largely through volumetric rates (i.e., per therm, kilowatt hour, or 100 cubic feet). A successful EE program will reduce the volume of sales and simultaneously reduce recovery of the fixed costs, which include the equity returns, so regulated utilities have what is called a "throughput disincentive" to carry out EE programs.

1 The authors wish to thank those members of *The Brattle Group* who provided comments including Larry Kolbe, Hannes Pfeifenberger, Bente Villadsen, Dan Kiernan, and Jenny Palmer.

There are various forms of decoupling, but the basic idea is that if sales exceed forecast, the utility will refund to customers the over-recovery of fixed costs. If sales are less than forecast, the utility will be able to add a charge to future rates to fully recover its fixed costs. This removes the throughput disincentive and therefore the conflict of interest for utility management. With decoupling in place, managers of regulated investor-owned utilities avoid one major hurdle to pursuing EE programs that are in the public interest and maintain their fiduciary duty to protect the interests of their shareholders.[2] However, a new hurdle has appeared in the form of a tangible regulatory risk of a lowered allowed return on equity (ROE) for utilities that implement decoupling.

In addition to management's conflict of interest in reducing sales volume, EE programs are likely to increase the variability of the utility's revenues because the effectiveness of the program adds another element of forecasting error into setting the revenue requirement. As decoupling policies become increasingly prevalent and important, some intervenors and commission staffs have argued that decoupling, by design, reduces the variability of revenues by decoupling cost recovery from sales volume, which, they argue, translates directly into reduced risk. Intervenors, therefore, have also argued that the regulated company's cost of capital be reduced because cost of capital is the payment to investors bearing business and financial risks.[3]

In the majority of decisions approving decoupling in the past, regulators did not explicitly conclude that decoupling reduces a utility's cost of capital. However, in a very visible minority, regulators did decrease the allowed ROE, with the reductions generally ranging from 10 to 50 basis points (bps) (100 bps = one percent). More ominously, intervenors in some gas, electric, and water utility rate cases have suggested that the decoupling impact on ROE should be as large as 250 to 300 bps.[4]

After reviewing a number of decisions where reductions were imposed by the regulators, we find that the reductions, whether moderate or substantial, appear to be based on theoretical arguments without the support of empirical evidence to demonstrate an actual relationship between decoupling and the cost of capital. To test this theory, we have completed the first empirical investigation, of which we are aware, on the hypothesis that decoupling lowers the cost of capital.

The findings of our analysis do not support the belief that utilities with decoupling have a lower cost of capital than utilities without decoupling. Contrary to what some might expect to find, at least on the basis of the opinions of certain intervenors and the (minority set of) judgments where commissions reduced allowed rates of return because of decoupling, we found that the estimated cost of capital for decoupled utilities was higher by a small but statistically significant amount.

2 There are three conditions that are likely to be necessary to ensure that a utility's management is enthusiastic about the effect of large-scale EE programs on their financial performance. The first is decoupling, as discussed in this paper, and the second is the timely and concurrent recovery of the direct EE costs. Although together these two conditions make the utility financially indifferent, they do not provide the utility with a strong reason to pursue energy efficiency. The third condition is a performance incentive, which gives the management a financial incentive and, when successful, positive news for shareholders. Although utilities operate under a regulatory bargain, investors value growth in earnings and wish to see some other real value when growth is being reduced by public policy directives.

3 See Chapter 20 of Brealey, Myers, and Allen, *Principles of Corporate Finance*, 9th edition, McGraw Hill Irwin, 2008.

4 For example, see pages 19-20 of "Phase 1B Testimony of Terry L. Murray on behalf of the Division of Ratepayer Advocates on Return on Equity Adjustments" before the California Public Utilities Commission, filed October 19, 2007, Docket No. I. 07-01-022.

Section 1 VOLUMETRIC RATES, DECOUPLING,[5] AND THE THROUGHPUT DISINCENTIVE

Under traditional ratemaking, regulated utilities collect their base revenues, including the return on capital they hope to earn, using a combination of fixed charges and volumetric rates. (Volumetric rates are in dollars per kilowatt-hour for electric utilities or dollars per therm for gas utilities. Revenues collected through volumetric rates vary with overall usage.[6]) Volumetric-based cost recovery does not follow the principle of basing rates on marginal cost because a large part of a utility's costs is fixed and does not vary with the level of output and sales. Traditionally, the fixed charges generate only a small proportion of total revenues and do not fully recover the fixed element of total costs. If actual sales are less than forecast sales used to set rates, the utility will not earn its allowed ROE.

Successful EE programs will reduce sales volume relative to what sales would have been without the EE program and perhaps relative to sales volumes in previous years. The effect of declining sales on the revenue requirement (as well as the effect of increases in prudent costs) will be addressed in the next general rate case; when base rates are reset based on actual sales, but the lost fixed cost recovery for the effect of past EE programs will remain. Even with revised volumetric rates in place as a result of a rate case (and taking into account the effect of EE programs), the throughput disincentive immediately comes back into effect, so that between general rate cases, any reduction in sales from EE programs results in a reduction in earned ROE. To counteract the effect of declining sales on earned ROE, the utility may be forced to file more frequent general rate cases, which are time consuming, expensive, and risky, and therefore not a desirable solution. Thus utilities with volumetric rates have a throughput disincentive to carry out more aggressive programs for their customers to reduce energy usage, lower their utility bills, and help meet climate change policy goals.

This tension is in contrast with the overall cost effectiveness of the EE programs from several other perspectives. It is regularly shown in regulatory filings that a wide variety of utility-administered EE programs are cost effective from society's point of view. Because of their cost effectiveness and emissions-reducing effects, a number of states have adopted formal EE resource standards or similar EE goals. A recent survey of electric utilities showed that ratepayer-funded EE expenditures increased by over 57 percent between 2007 and 2009.[7] It is evident that the issue of addressing the throughput disincentive is becoming increasingly important. Decoupling of one form or another has been approved for natural gas local distribution companies (LDCs) in about 28 states and is pending in 4 more.[8] Decoupling has also been approved for electric utilities in about 13 states and is pending in 7 more.[9]

5 This study assesses two different ratemaking approaches and uses the term "decoupling" to include both: 1) decoupling with general revenue true-up mechanisms and 2) straight fixed-variable rates. A related form of decoupled ratemaking is a lost revenue adjustment mechanism that focuses specifically on the impacts of EE programs on base revenues. Some discussions of decoupling limit the term to just the first approach and some include all three. There is no agreement about which of the three is best. This paper is only interested in the cost of capital impacts, not the comparative merits of the three types of decoupling. We include the first two decoupling approaches because they have similar impacts in insulating revenues collected from changes in the commodity throughput, other than those driven by increased numbers of customers. As is generally true, the companies in our gas sample use only these two forms of decoupled ratemaking.

6 A small percentage of fixed costs are recovered through customer charges and are not part of the decoupling issue. Some fixed costs for large customers are recovered in demand charges and are much less affected by EE programs. Finally, fuel and purchased power are large, variable costs for electric and gas consumers, and are both independent of the throughput disincentive, because revenues and costs go up or down together and changes generally cancel each other out.

7 "Summary of Ratepayer Funded Electric Efficiency Impacts, Expenditures and Budgets," Based on CEE/IEE Industry Database, Updated IEE Brief, May 2010.

8 American Gas Association, *Innovative Rates, Non-Volumetric Rates and Tracking Mechanisms: Current List*, as of June 2010.

9 Institute for Energy Efficiency, *State Energy Efficiency Frameworks*, July 2010, pages 2-3; updated for adoption in Arizona and moving Nevada to a different policy.

If energy efficiency is the goal, decoupling is a useful form of regulated ratemaking that separates, or decouples, the collection of base revenues from sales of the product, so that utility profits are not hurt from the reductions in sales (for example, caused by EE programs). Decoupling removes the throughput disincentive, aligns the interests of utility management with the public policy goal of EE, and reduces sales with the management goal of earning the allowed rate of return for investors.

Section 2 DECOUPLING AND THE COST OF CAPITAL

Decoupling was adopted for three electric utilities in California in the 1980s as an adjunct to EE policies and has continued ever since, except for a brief hiatus during restructuring after 1998. California utilities have never had their cost of capital explicitly reduced because of decoupling. However, as decoupling has grown in importance in recent years within other states, a substantial regulatory risk has also emerged in the form of the potential reduction in the allowed ROE.

To date, about one-fifth of regulatory decisions that we have reviewed related to decoupling for gas and electric utilities have concluded that decoupling does reduce a utility's cost of capital, and accordingly these decisions have reduced the allowed ROE. The reductions in allowed ROEs have ranged from 10 to 50 bps. However, in our review of these cases, we could not find any empirical evidence that supported a reduction of any particular magnitude. The other four-fifths of the decisions adopted decoupling without explicitly reducing the cost of capital. Since the subject has gained greater notoriety, regulatory risk may still resurface as an issue when those utilities litigate their cost of capital in future general rate cases. We have developed an approach to investigate whether any reduction in the allowed ROE is warranted, and if so, how small or how large the reduction should be.

A utility's operating earnings (i.e., earnings before income taxes) are the difference between base revenues (non fuel) and the sum of all prudent costs, which include operations and maintenance (O&M), administrative and general (A&G), depreciation, and interest. There are several sources of variability in the base revenue stream that can also be eliminated by the decoupling mechanisms analyzed here. EE programs decrease revenues because they decrease sales. Other increases and/or decreases in base revenue are driven by changes in weather, business activity over the business cycle, the net number of new customers, and the number of delinquent bills. By design, decoupling eliminates or significantly weakens the linkage between revenues and the volume sold, independent of the source of variability.

Decoupling stabilizes revenues, but net income still varies. Although depreciation and interest expense are relatively stable, other costs can change quickly between rate cases. At times of rapid capital investment, such as the present for utilities that are facing significant environmental retrofits, depreciation and interest may also increase rapidly so that general rate cases are frequently required. O&M and A&G costs can rise more than revenue, but are reasonably predictable and do not vary as directly with sales as do revenues. Therefore, if decoupling stabilizes the revenue side of the earnings equation, does it stabilize operating earnings as well? This leads directly to the question: if decoupling reduces revenue variability largely independent of the cost situation, does risk go down at the same time? A more targeted question is whether decoupling reduces the non-diversifiable risk that determines the cost of capital in financial markets? The answer is <u>not</u> a simple "yes."

Not all risks or sources of variance in earnings affect the cost of capital equally, because investors can simply avoid certain risks. For example, extremes of weather, including extreme mildness, will cause variance in a single utility's revenues and is a risk factor for that utility's earnings. However, investors can assemble a portfolio of utility stocks from across the U.S. climate zones and mitigate the weather effects of individual stocks in the portfolio. For the portfolio of utility stocks, the effect of weather variations should largely cancel out, removing weather as a source of investment risk, and negating its effect on the cost of capital. Portfolio formation removes other such risks that can be minimized by diversification.

Non-diversifiable risks, also known as "business risks," are the risks that remain after diversification. They are the risks that drive a company's cost of capital because investors must bear them. The distinction between diversifiable risk and non-diversifiable business risk is important to recognize when evaluating the effect of decoupling, or other regulatory policy, on a company's cost of capital. Simply reducing total risk does not imply that the cost of capital has been reduced. The risk reduced must be part of a company's business risk to affect its cost of capital, so only reductions in business risk justify a reduction in a regulated company's allowed ROE. Thus, we believe that there is strong need to address the empirical question of whether the presumed decrease in risk from adoption of decoupling policy results in a measurable decrease in the cost of capital for regulated utilities.

Section 3 AN EMPIRICAL TEST OF THE EFFECT OF DECOUPLING ON THE COST OF CAPITAL

For the nearly five year study period from October 2005 to June 2010, we examined a sample of exchange-traded companies in the natural gas distribution sector for which estimates of the cost of capital were available. For these holding companies, we examined each of their regulated gas LDC subsidiaries and identified whether and when each LDC had decoupled versus traditional volumetric rates. We then compared the estimated cost of capital across two mutually exclusive groups: regulated utilities with all or a large share of revenues collected under decoupled ratemaking <u>versus</u> regulated utilities with all or a large share of traditional volumetric rates.

During the study period, co-author Dr. Michael Vilbert and others at *The Brattle Group* participated in a number of rate proceedings where the cost of capital was estimated for a sample of regulated gas LDCs. Some of the LDCs examined in these proceedings had decoupled rates at the beginning, some did not, and some became decoupled during the period. Hence, the cost of capital estimates from these proceedings provide a natural experiment on the impact of decoupling on the cost of capital. The specifics of our study are described below.

Developing a Sample of Traded Natural Gas Holding Companies

Our analysis is based on a carefully selected sample of holding companies that were exclusively or primarily involved in the regulated natural gas distribution industry. Over the study period, *Brattle* expert witnesses submitted cost of capital testimony 18 separate times based on an evolving sample of 6 to 12 gas LDC holding companies. Across the 18 dates, over 170 estimates of the cost of capital were made and submitted into evidence, subject to scrutiny.

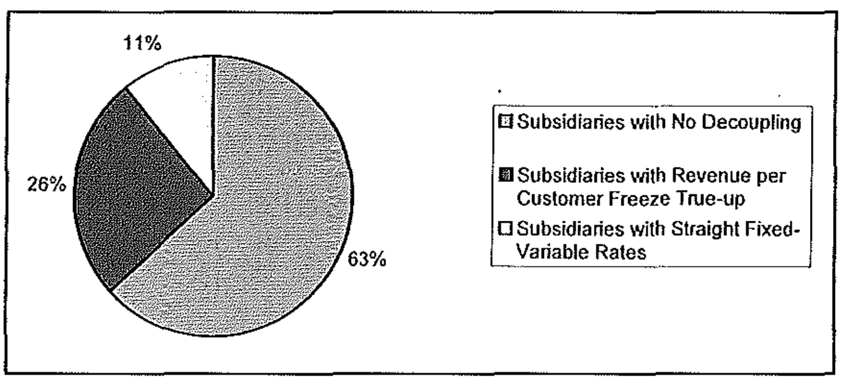
In each proceeding, *Brattle* selected a sample from the universe of all traded natural gas LDC holding companies followed by the investment advisory service, the *Value Line Investment Survey*, using six sample selection criteria that are designed to remove companies with characteristics that could bias the cost of capital estimates.[10] Over the study period, the selection criteria remained the same, but the composition of the sample changed slightly (i.e., due to mergers). Thus, we have assembled a record of statistically valid estimates of the change in the cost of capital for every holding company in the sample for the study period.

Determining the Degree of Decoupling for Companies in the Sample

Holding companies, not their subsidiaries, have the market information necessary to estimate the cost of capital, because they have publicly traded stock. However, it is the individual state-regulated subsidiaries, not the holding companies themselves, that can be granted decoupled rates by state regulators. Hence, to characterize the degree of decoupling of each holding company, it is necessary to examine the decoupling policies of its subsidiaries in each state in which the subsidiary operates.[11]

To begin, we identified all regulated gas LDCs belonging to each holding company in the sample and then used a combination of primary and secondary sources to identify the subset of those gas LDCs that had decoupled rates during the study period. The 12 holding companies collectively held 46 regulated natural gas LDC subsidiaries as of June 2010. We used a broad definition of decoupling and included true-up decoupling schemes and straight fixed-variable (SFV) rates.[12] Figure 1 shows the distribution in June 2010 of true-up and SFV decoupling schemes among the 46 subsidiaries in our sample.

Figure 1 **Shares of Decoupling Mechanisms in Natural Gas Sample (June 2010)**



10 The sample selection criteria are:

a. An investment grade credit rating, i.e., BBB- or better from S&P;

b. No dividend cuts during the last five years;

c. Revenues or assets > $300 million;

d. Greater than half of the assets in the regulated line of business, either natural gas distribution or regulated electric operations;

e. Data available from Value Line, Bloomberg, and Moody's; and

f. No major mergers or acquisitions during the last three years.

11 In this report, we use the term "subsidiary" to refer to the part of a utility that is regulated at the state level. A particular holding company might own two utilities that are separate corporations. Assume the first is located in a single state, while the second has a service territory extending over three states. In our analysis, this holding company would have four "subsidiaries."

12 See footnote 6. We did not find any gas LDC companies with decoupling in the form of a lost fixed revenue adjustment mechanism, which is found frequently in electric utilities.

In our sample of 46 subsidiaries of 12 gas LDC holding companies, 37 percent had decoupling policies in place. We believe this is higher than the overall proportion of all LDCs in the population having decoupled rates. In total, we estimate there are approximately 49 LDCs across the U.S. with decoupling,[13] out of an estimated population of over 300 LDCs,[14] implying that the proportion with decoupling is less than one-sixth, as shown below in Table 1.

Table 1 **Natural Gas Decoupling Penetration**

Natural Gas Delivery Utilities

Population and *Brattle* Sample of Regulated Subsidiaries: Total and Decoupled

	Gas LDC Subsidiaries	Number Decoupled	Share Decoupled
In Total Population	341	49	14%
In *Brattle* Sample	46	17	37%

Notes
The total row refers to all gas LDCs, counting them per state separately in which it delivered volumes of at least five bcf in 2008.

The sample row refers to 12 publicly-traded companies that meet *Brattle* criteria.

Not only does decoupling vary by subsidiary, but for some subsidiaries in our sample the status of decoupling has changed over time because state regulators have approved new mechanisms and, in some cases, changed or eliminated decoupling. To reflect this variation, we developed a robust decoupling index for each holding company over time. First, for each subsidiary, we made a specific designation of whether or not it was decoupled for each year in the sample period. Second, we aggregated the decoupling scores of the regulated subsidiaries to produce an overall decoupling score for the holding company. In this aggregation, we weighted all of the individual subsidiary scores (i.e., one or zero) based on their volume of gas distributed in 2008.

13 This is based on our examination of published reviews, for example, *Review of Distribution Revenue Decoupling Mechanisms*, Pacific Economics Group, March 2010, and *State Energy Efficiency Regulatory Frameworks*, Institute for Electric Efficiency, January 2010.

14 Based on EIA Form 176 data. In counting LDCs, such as in Figure 1, we exclude LDCs transporting less than five bcf per year. In estimating the index of decoupling for a holding company at points in time, we do not exclude any subsidiaries.

Table 2 below shows the decoupling index for each natural gas holding company in the sample at the end of the study period (June 2010).

Table 2 Decoupling Index for the Natural Gas Sample (June 2010)

Company		Number of Gas LDC Subsidiaries	Decoupling Index
AGL		6	**0.82**
Atmos		12	**0.01**
Laclede		1	**1.00**
New Jersey Resources		1	**1.00**
Nicor		1	0.00
NiSource		9	**0.40**
Northwest Natural		3	**0.93**
Piedmont		3	**0.75**
South Jersey Industries		1	**1.00**
Southwest Gas		3	**0.68**
WGL		3	0.00
Vectren		3	**1.00**
	Total	**46**	

Notes

Each subsidiary is counted once per state in which it operates.

The aggregate decoupling score for each group is the number of its gas LDC subsidiaries with decoupling, multiplied by the 2008 gas volumes for those subsidiaries, then divided by the total 2008 group gas volumes.

Estimating the Cost of Capital for Companies in the Sample

The cost of capital is defined as the return investors require in order to invest in an asset, or the expected return available on investments of comparable risk. There are a number of good and frequently used approaches for estimating the cost of capital for a company. One approach, though not used here, is to create estimates using historical data to estimate the parameters of a cost of capital model (e.g., estimate the Capital Asset Pricing Model (CAPM) beta using historical stock price returns). Another approach, which we do use here, is to compare current stock prices with forward-looking forecasts of cash flows from the business (e.g., one can use discounted cash flow (DCF) methods to compare the value of expected future dividends from the stock with current stock prices to estimate the expected returns). For this study, we used the DCF approach to estimate the cost of capital to analyze the effect of decoupling, because the DCF approach has the advantage of reflecting changes in the cost of capital more quickly than do other approaches that rely on the analysis of historical data.[15] In the DCF model, the discount rate that makes the present value of expected future dividends equal to the current stock price is the estimate of the cost of equity (COE) for the company.

15 For example, estimates of beta, the systematic risk parameter in the CAPM, are normally based upon three to five years of historical data. A policy that changed a company's cost of capital would lead to a change in the company's beta, but that change would not be fully reflected in the beta estimate for three to five years.

We chose to use a multi-stage version of the DCF model. In this version, security analysts' forecasts of company-specific future earnings were used for a five-year, first stage of the multi-stage analysis to estimate expected dividends.[16] Later stages were added to ensure that the growth rate for each company eventually settled down to a single long-term growth rate based on the forecast of the long-term U.S. GDP growth rate. In particular, forecast growth rates for years 6 through 10 were linearly trended between company-specific earnings growth rates for the first 5 years and the long-term GDP growth rate in effect starting in year 11. Earnings growth was translated into corresponding expected dividend payments over time.

The COE is information of interest to regulators when they set the allowed ROE for a utility, so our focus is ultimately on whether there is a measurable reduction in the COE from the policy of decoupling. In general, the COE increases not only with increased business risk but also with increased financial risk.[17] Therefore, in testing for an impact on the cost of capital from decoupling, we systematically account for differences in the COE in different holding companies in the sample that arise from different levels of financial risk, which has nothing to do with decoupling.

To control for the effect of differences in capital structure (i.e., differences in financial risk) among the sample companies, we converted estimates of the COE into corresponding estimates of the overall after-tax weighted-average cost of capital (ATWACC).[18] The ATWACC measures the cost of capital for the business itself, while the COE estimate represents the cost of equity capital taking into account the equity-holders' additional financial risk from the company's level of debt financing. In other words, the ATWACC captures only the effect of business risk, while the COE is also affected by financial risk. For that reason, we use the ATWACC in our statistical analysis.

Statistical Analysis of Decoupling on the Cost of Capital

To determine the impact of decoupling on the cost of capital, we carried out the five statistical tests described below. The results of these tests were all in general agreement and collectively demonstrate that the overall impact in our data sample of the holding companies from decoupling of their rates was most likely a small increase, rather than a decrease, in their cost of capital. The estimated increases from the tests ranged from 6 to 42 bps. In some of the tests, the conclusion of an increase in cost of capital was statistically significant. In other tests, a small decrease cannot be ruled out, but even in those cases, it is far more likely that the rate increased rather than decreased. The estimated impacts and associated 95 percent confidence intervals for all five statistical tests can be seen in Figure 4. Our conclusion that decoupling most likely caused a small positive impact on cost of capital is shown in Figure 4 by noting that the bulk of the confidence interval in every case is above the zero "no effect" horizontal line.

16 We also implemented the test using the simple or constant growth DCF method. The results (not reported here) were not substantially different than those based upon the multi-stage DCF method.

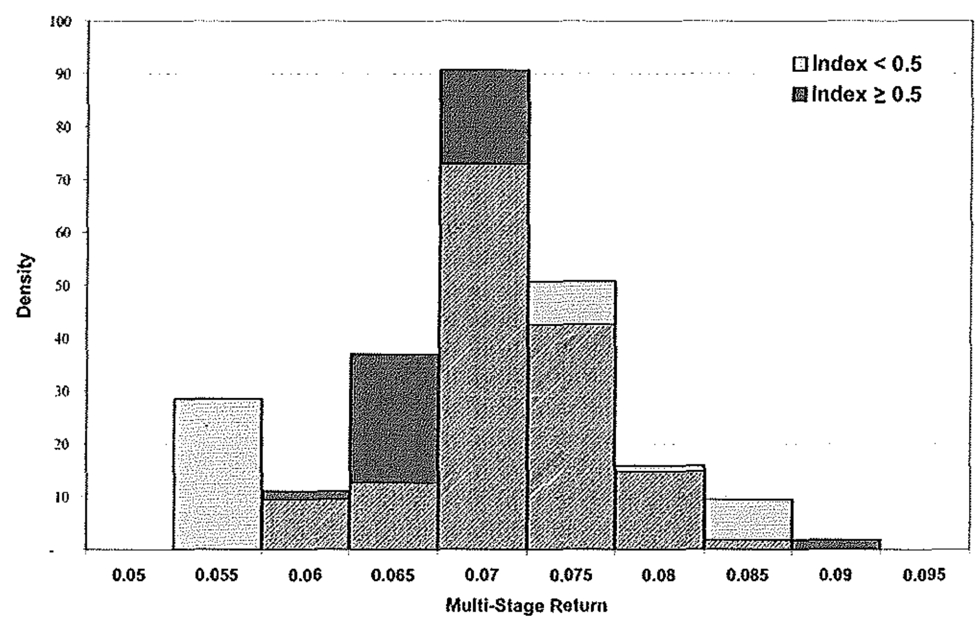
17 Financial risk is related to the degree to which the company's assets are debt financed. The greater the share of debt in the capital structure, the greater the interest that must be paid out of operating revenues before any shareholder earnings are available.

18 To be specific, the after-tax weighted-average cost of capital (ATWACC) is the measure we use. ATWACC is a weighted average of both the equity and debt returns after taking into account the tax deductibility of interest payments. The weights used in the calculation are the market values of debt and equity in the capital structure. See Chapter 20 of Brealey, Myers, and Allen, *op cit.*

In the first test of the impact of decoupling on the cost of capital, we split the sample at each observation date into one of two groups: the group where the decoupling index (which can vary between zero and one) is below 0.5, and the remaining utilities in the group where the decoupling index is greater than or equal to 0.5. We then compare the frequency distribution of the cost of capital estimates (specifically, the ATWACC calculated using a multistage DCF) for each group.

If the impact of decoupling on the cost of capital is large, we would expect the cost of capital estimates for the group with a high decoupling index to be noticeably lower than those with low decoupling index. Figure 2 displays the distribution of returns with a decoupling index of greater than 0.5 (dark blue) on top of the distribution of returns with a decoupling index of less than 0.5 (light blue). The cross hatch represents areas of overlap. We see that any impact of the differences in cost of capital from decoupling between the groups is smaller than the diversity in cost of capital within each group from other differences.

Figure 2 **Distribution of Returns**



The distribution of estimated cost of capital for holding companies that were highly decoupled (dark blue) and for holding companies that were not highly decoupled (lighter blue).

The first result is that the average cost of capital for the highly decoupled group was 7.313 percent, and the average cost of capital for the other group was 7.257 percent. Hence, we find that the more highly decoupled group of holding companies had a cost of capital that was slightly higher on average (5.6 bps) than the group with less decoupling. To examine the statistical significance of this first conclusion, we carried out a two-sample t-test and found that the test gave a 95 percent confidence interval of the difference in average cost of capital between the groups that ranged from 17 bps lower up to 28 bps higher for the highly decoupled group. Therefore the observed difference in means is not statistically different from zero at this confidence level.[19] In other words, a t-test on the two groups leads to an expectation that the drop in cost of capital from decoupling is highly likely to be less than 17 bps and is actually somewhat more likely to be positive than negative. The results of this first test raise the question of whether it is possible that companies with decoupling in place may actually have a higher cost of capital than companies without decoupling. The answer is that it is indeed possible; if investors view decoupled rates as a signal that the company faces some additional source of risk, then the cost of capital could actually increase if rates were decoupled.

As a hypothetical example, consider a utility whose sales volume was primarily driven by a highly diversifiable risk such as weather, and the other factors including EE impacts are assumed to be absent. In this example, there would be no material reduction in the cost of capital from the risk reduction due to decoupling. However, suppose that investors view the implementation of decoupled rates as an implication that the utility would be under increased regulatory scrutiny which could increase the possibility of disallowances, or that the decoupled rate program would limit the utility's ability to recover unanticipated costs outside of the decoupling program. In such a case, investors may see the decoupled rates as a sign that other risks could increase, and therefore the cost of capital could increase because of those risks. In other words, *a priori* we do not know whether decoupled rates will increase or decrease a utility's cost of capital — it is an empirical question that can be answered only through the kind of statistical analysis that we have done here.

Our first statistical test put a 95 percent confidence interval range on the estimated impact from decoupling on the cost of capital that is almost 50 bps wide. A natural next step is to see if there are patterns to the cost of capital data that can account for enough of the variability in returns in the subgroups to more tightly constrain the assessed limits on the decoupling impact.

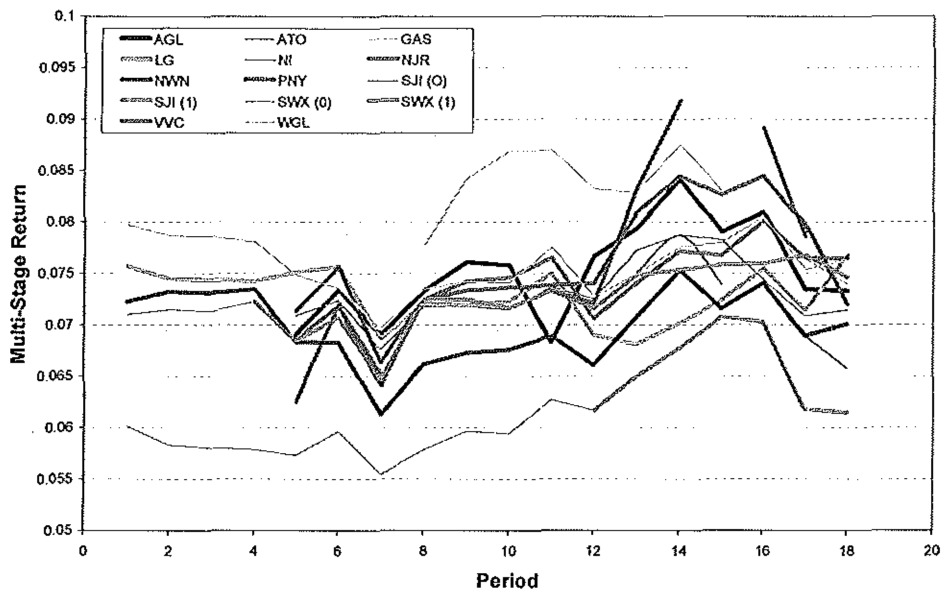
Figure 3 displays the cost of capital estimates by time period for each of the 12 holding companies in the sample and shows that the cost of capital estimates vary by time period and company. (In Figure 3, for each time series of cost of capital estimates for one holding company, the bold lines represent the exact periods in which the company's decoupling index was high, i.e., greater than or equal to 0.5.) It is evident that there is a great deal of shared time variation[20] in the estimates, in addition to a great deal of company-specific variation. This observation serves to suggest additional statistical tests that should separate out the effects of shared time variation and company-specific variation in the statistical analysis.[21]

19 This confidence interval was from a t-test based on the assumption that the sample variances of the two groups were equal. The assumption of equal variance makes the 95 percent confidence interval range slightly smaller but does not change the conclusion that the difference in means is not statistically significant.

20 Shared time variation is the variation in the ROE estimates that occur as a result of being done at different points in time.

21 The broken lines in Figure 3 are due to missing data for some estimation periods.

Figure 3 **Cost of Capital Over Time**



The estimated cost of capital by period for each holding company. Bold lines represent periods in which the company's decoupling index was greater than or equal to 0.5.

The four additional statistical tests were done using linear regression analyses. In all four additional tests, we accounted for shared time and company-specific variation through the use of time period- and company-specific indicator variables, which are common ways to isolate the impact of such factors from the impact of the quantity you are testing (here the level of decoupling). The use of these indicator variables accounted for over 80 percent of the variation in the estimated costs of capital in the data.[22] The four tests differ in how the decoupling index was treated and whether the prior value of the cost of capital was included in the regression. In two of the tests, the decoupling is represented as an indicator variable with a value of one if decoupling is greater than or equal to 0.5 (highly decoupled) and zero if it is less than 0.5. In the other two tests, decoupling is represented using the actual numerical value of the decoupling index. The use of the actual value of the decoupling index is to determine whether the cost of capital estimates vary even if decoupling affects a relatively small or large portion of the assets of the holding companies.

To summarize, the four additional tests consist of two regressions with decoupling, represented with an indicator variable, carried out both with and without the inclusion of the prior cost of capital. The other two regressions, with decoupling represented by the decoupling index, were carried out both with and without the inclusion of the prior cost of capital in the regression.

[22] Examination of the regression residuals with a normal quantile-quantile plot and carrying out a Jarque-Bera test did not indicate problems with either non-normality or heteroscedasticity. However, the regression residuals do show some degree of serial correlation so we used Newey-West adjusted standard errors when making inference regarding the statistical significance of the impact of decoupling on the cost of capital.

In the first regression analysis, adding an indicator for the decoupling index being at least 0.5 into the regression leads to an estimated increase of 36 bps in the cost of capital from being highly decoupled (with a Newey-West 95 percent confidence interval ranging from +16 to +55 bps). This result is consistent with the results of the initial t-test, because both include the region from +16 to +28 bps in their 95 percent confidence interval range. The impact of being highly decoupled is greater than zero (with statistical significance at the 95 percent confidence level). In other words, we have been able to show that the cost of capital in our sample was higher for decoupled companies than for companies with volumetric rates by taking into account company-specific differences and the variation in the cost of capital over time.

In the second regression analysis, we estimated the impact of decoupling by using the decoupling index itself as an explanatory variable in the regression and by taking into account company-specific differences and the variation in the cost of capital over time. This test shows that the increase in the cost of capital is 40 bps for a fully decoupled company compared to one with no decoupling (zero decoupling index).[23]

For the third and fourth regression analyses, we re-ran the prior two regressions with the additional inclusion of the prior period's cost of capital. The prior period's cost of capital was included to directly address some serial correlation, which we had seen in regression residuals from the base regression of cost of capital on period and company. The two regressions differ by the representation of decoupling as either an index or as an indicator variable. We note that the time intervals between the data points were not of uniform length because the underlying cost of capital studies are done when they are needed for regulatory proceedings, not on any fixed schedule. We believe the results of these third and fourth regressions still provide reliable evidence.[24] Both when we included the indicator of the decoupling index being at least 0.5 into the regression and when we included the decoupling index itself into the regressions, we found that the 95 percent confidence interval[25] on the impact of decoupling contained the common region from +22 to +28 bps found in the prior three tests.

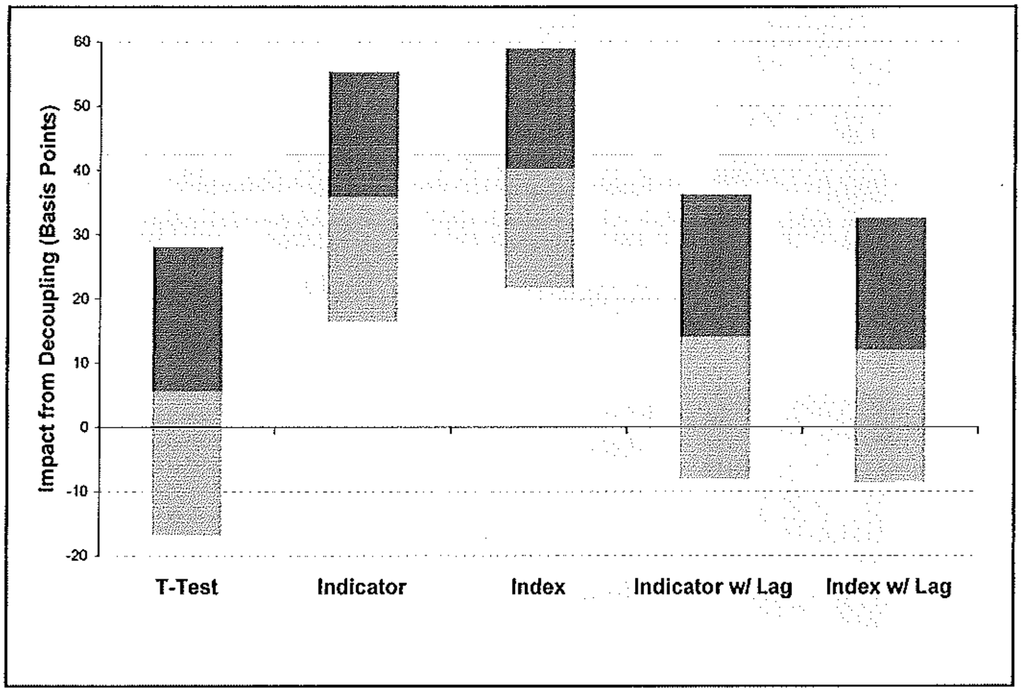
The results of the five tests provide what we consider to be strong evidence that the overall impact on companies' cost of capital following decoupling of their rates was more likely an increase than a decrease. The estimated impact and associated 95 percent confidence intervals for all five statistical tests can be seen in Figure 4.

23 The Newey-West 95 percent confidence interval ranges from +22 bps up to +59 bps. In this case, the positive result is statistically significant at the 95 percent confidence interval. This result remains consistent with the prior two tests, because they all contain the interval from +22 to +28 bps in their 95 percent confidence intervals.

24 We believe that the non-uniform periods of time are not an important issue in this analysis. Capital markets adjust to new information on a daily or even more frequent basis. The real issue is whether there were important changes between the observations to give them a degree of independence. Even to the casual observer, it is clear that the period from 2005 to 2010 was a period of change in U.S. financial markets, so the observations appear sufficiently independent to us.

25 For the regressions with the prior cost of capital included, "HC3" standard errors were used as described by Long and Ervin, "Using Heteroscedasticity Consistent Standard Errors in the Linear Regression Model," *The American Statistician*, 2000.

Figure 4 **Summary of Estimated Impact of Decoupling on Cost of Capital**



Conclusion

Our statistical tests do <u>not</u> support the position that the cost of capital is reduced by the adoption of decoupling. If decoupling decreases the cost of capital, these tests strongly suggest that the effect must be minimal because it is not detectable statistically.

As decoupling continues to grow in importance, cases will arise where intervenors and commission staff may explore the extent to which decoupling reduces business risk and the utility's cost of capital. To date, in a minority of cases in which decoupling was approved, the utility explicitly had their allowed ROE reduced. Our research leads us to conclude that these reductions have been implemented with no empirical analysis to support the ROE reduction. The results of our analysis show that if such empirical analysis had been done, it is unlikely that it would have supported even the moderate reductions in allowed ROE that were imposed on the utilities.

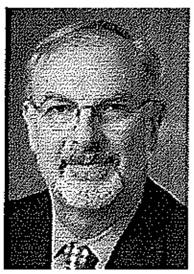
Where decoupling is associated with implementing enhanced EE programs (as is almost always the case), adopting a reduction in allowed ROE in essence punishes a utility for pursuing EE programs. If a utility's management fears an unjustified reduction in the allowed ROE as a result of decoupling, the original disincentive to pursue EE programs is recreated in a new form, and the purpose of decoupling to align the interests of ratepayers, shareholders, and society as a whole may be frustrated.

About the Authors

Dr. Joseph B. Wharton
Principal
Telephone: +1.415.217.1000
Email: Joe.Wharton@brattle.com

Dr. Wharton specializes in strategic economic issues of the electric power industry, including electric industry restructuring, strategic planning, and asset valuation. He has worked at major utilities on both the West and East Coasts, as well as for the Electric Power Research Institute (EPRI) and Dun and Bradstreet. He also served as a faculty instructor for the Annual EEI Electric Rate Advanced Course in Indianapolis, Indiana.

Dr. Wharton received his Ph.D. and M.A. in Economics from the University of California at Los Angeles.



Dr. Michael J. Vilbert
Principal
Telephone: +1.415.217.1000
Email: Michael.Vilbert@brattle.com

Dr. Vilbert is an expert in finance, economics, and utility regulatory policy and rate-making. He has testified before the U.S. Federal Energy Regulatory Commission, the Canadian National Energy Board, numerous state and provincial regulatory commissions and boards, and in federal court.

Dr. Vilbert received his Ph.D. in Financial Economics from the Wharton School of the University of Pennsylvania.

Dr. Richard E. Goldberg
Principal
Telephone: +1.415.217.1000
Email: Rich.Goldberg@brattle.com

Dr. Goldberg is an industry leader in the use of financial techniques to calculate the value and manage the risks associated with physical assets (e.g., power plants), contract commitments (e.g., fuel purchase agreements), and retail customers. He applies these techniques to buy/sell decisions, asset management, capital budgeting, commodity trading, retail service design, and corporate risk management.

Dr. Goldberg received his Ph.D. and M.S. in Physics from Stanford University.

Dr. Toby Brown
Senior Associate
Telephone: +1.415.217.1000
Email: Toby.Brown@brattle.com

Dr. Brown specializes in the regulation and economics of the gas and electricity sectors. He has assisted energy regulators, network owners, gas suppliers, and electricity generators in North America, Europe, and Australia. He also has particular expertise in the application of incentive-based regulation to the energy sector and has been involved in ratemaking proceedings for gas and oil pipelines in the U.S. and Canada.

Dr. Brown received his D.Phil from the University of Oxford.

To learn more about our expertise and our consulting staff, including our affiliated senior advisors, please visit www.brattle.com.