BEFORE THE

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

PUBLIC UTILITIES COMMISSION

RE: INVESTIGATION OF	**)**	
NARRAGANSETT ELECTRIC	**)**	
COMPANY d/b/a/ NATIONAL GRID'S	**)**	**DOCKET NO. 4323**
PROPOSED CHANGES TO ELECTRIC	**)**	
AND GAS DISTRIBUTION RATES	**)**	

DIRECT TESTIMONY OF

MATTHEW I. KAHAL

ON BEHALF OF THE

DIVISION OF PUBLIC UTILITIES AND CARRIERS

AUGUST 30, 2012

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MATTHEW I. KAHAL

I. QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Matthew I. Kahal. I am employed as an independent consultant retained in this matter by the Division of Public Utilities and Carriers ("Division"). My business address is 10480 Little Patuxent Parkway, Suite 300, Columbia, Maryland 21044.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND.

A. I hold B.A. and M.A. degrees in economics from the University of Maryland and have completed course work and examination requirements for the Ph.D. degree in economics. My areas of academic concentration included industrial organization, economic development and econometrics.

Q. WHAT IS YOUR PROFESSIONAL BACKGROUND?

I have been employed in the area of energy, utility and telecommunications consulting for the past 30 years working on a wide range of topics. Most of my work has focused on electric utility integrated planning, plant licensing, environmental issues, mergers and financial issues. I was a co-founder of Exeter Associates, and from 1981 to 2001 I was employed at Exeter Associates as a Senior Economist and Principal. During that time, I took the lead role at Exeter in performing cost of capital and financial studies. In recent years, the focus of much of my professional work has shifted to electric utility restructuring and competition.

Prior to entering consulting, I served on the Economics Department faculties at the University of Maryland (College Park) and Montgomery College teaching courses on economic principles, development economics and business.

A complete description of my professional background is provided in Appendix A.

Q. HAVE YOU PREVIOUSLY TESTIFIED AS AN EXPERT WITNESS BEFORE UTILITY REGULATORY COMMISSIONS?

A. Yes. I have testified before approximately two-dozen state and federal utility commissions in more than 380 separate regulatory cases. My testimony has addressed a variety of subjects including fair rate of return, resource planning, financial assessments, load forecasting, competitive restructuring, rate design, purchased power contracts, merger economics and other regulatory policy issues. These cases have involved electric, gas, water and telephone utilities. In 1989, I testified before the U. S. House of Representatives, Committee on Ways and Means, on proposed federal tax legislation affecting utilities. A list of these cases may be found in Appendix A, with my statement of qualifications.

Q. WHAT PROFESSIONAL ACTIVITIES HAVE YOU ENGAGED IN SINCE LEAVING EXETER AS A PRINCIPAL IN 2001?

A. Since 2001,1 have worked on a variety of consulting assignments pertaining to electric restructuring, purchase power contracts, environmental controls, cost of capital and other regulatory issues. Current and recent clients include the U.S. Department of Justice, U.S. Air Force, U.S. Department of Energy, the Federal Energy Regulatory Commission, The U.S. Environmental Protection Agency, Connecticut Attorney General, Pennsylvania Office of Consumer Advocate, New Jersey Division of Rate Counsel, Rhode Island Division of Public Utilities, Louisiana Public Service Commission, Arkansas Public Service Commission, Maryland Department of Natural Resources and Energy Administration, and MCI.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE RHODE ISLAND COMMISSION?

A. Yes. I have testified on cost of capital and other matters before this Commission in gas and electric cases during the past 25 years. This includes my testimony on fair rate of return submitted in Narragansett Electric Company's 2009 electric base rate case (Docket No. 4065). A listing of those cases is provided in my attached Statement of Qualifications.

Please note that in addition to my participation in this and past Rhode Island Commission rate cases, I am currently assisting the Division with Narragansett's pending application for authority to issue up to $250 million of long-term debt (Division Docket No. D-12-12). This Application was originally filed on April 26, 2012.

II. OVERVIEW

A. Summary of Recommendation

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

A. I have been asked by the Rhode Island Division of Public Utilities and Carriers ("the Division") to develop a recommendation concerning the fair rate of return on the electric and gas distribution utility rate bases of Narragansett Electric Company ("Narragansett" or "the Company"). This includes both a review of the Company's proposal concerning rate of return and the preparation of an independent study of the cost of common equity. I am providing my recommendations to the Division and its consultants for use in calculating the test year annual revenue requirement for both electric and gas service in this case.

As the Commission is aware, Narragansett is not an independent company, nor is it publically traded. It is owned by National Grid USA, which itself is a wholly-owned subsidiary of a much larger foreign company, National Grid PLC. National Grid USA owns and operates a number of electric and gas utilities (primarily "wires and pipes" utility companies) in the Northeast.

Q. WHAT IS THE COMPANY'S RATE OF RETURN PROPOSAL IN THIS CASE?

A. As presented on Schedule RBH-10, page 1 of 1, the Company requests an authorized overall rate of return of 7.85 percent on its electric rate base and 8.24 percent on its gas rate base.[1] The proposed capital structure based on its end of test year (December 31, 2011) balance sheet with certain adjustments, including a large

[1] Please note that the Company provided the Division with a data response on August 21, 2012 slightly revising its rate of return to 7.89 percent on the electric side and 8.27 percent on the gas side. These changes are due to errors recently discovered by the Company, and I am currently reviewing this response.

adjustment to reflect a new issuance of long-term debt planned for later this year. This results in a capital structure consisting of 49.0 percent long-term debt, 1.2 percent short-term debt, 0.2 percent preferred stock and 49.6 percent common equity. The Company requests a return on the common equity ("ROE") component of 10.75 percent for both electric and gas. The overall rate of return, cost of debt and cost of equity recommendations are sponsored by the Company's outside witness, Mr. Robert Hevert. I note that Mr. Hevert's recommendation of a 10.75 percent return on equity is nearly a full percentage point lower than the 11.6 percent ROE requested by the Company in its last rate case in 2009.

Q. IF THE COMPANY REQUESTS AN IDENTICAL RETURN ON EQUITY OF 10.75 PERCENT FOR BOTH ELECTRIC AND GAS SERVICE, WHY DOES THE OVERALL RATE OF RETURN DIFFER FOR THESE TWO SERVICES?

A. The difference in overall return between electric and gas (i.e., 7.85 percent electric versus 8.24 percent gas) is due to differences in the cost of debt. There are certain high cost legacy debt issues (i.e., First Mortgage Bonds that are specifically secured by gas assets) that are direct assigned to gas service.

Q. HOW DOES THE COMPANY'S PROPOSAL IN THIS CASE COMPARE WITH NARRAGANSETT'S MOST RECENT AUTHORIZED RATE OF RETURN?

A. The Company's currently authorized return is based on a 51/49 (debt/equity) capital structure and a 9.8 percent ROE. The 9.8 percent return on equity was set in the Company's 2009 electric rate case decided in early 2010 (Docket No. 4065). The 51/49 capital structure was the result of a settlement agreement approved by the Commission early this year. Thus, the Company's proposal in this case is a large increase in the authorized return on equity (from 9.8 to 10.75 percent), and the Company's proposed capital structure is in line with the settlement capital structure.

Q. DOES THE COMPANY'S PROPOSED CAPITAL STRUCTURE INCLUDE ESTIMATES OF ADDITIONAL FINANCINGS?

A. Yes. The proposed capitalization includes a planned $150 million issue of long-term debt scheduled to take place in later this year at an assumed all-in cost of 4.88 percent. For capital structure purposes, the debt proceeds are assumed to be used entirely to reduce the very large short-term debt balance. I discuss the implications of this debt issuance in more detail later in my testimony.

Q. WHAT IS YOUR RECOMMENDATION AT THIS TIME ON RATE OF RETURN?

A. As summarized on Schedule MIK-1, page 1 of 3, I am recommending an overall rate of return on Narragansett's electric utility rate base of 7.11 percent and 7.39 percent on the gas utility rate base. This includes for both gas and electric a return on common equity of 9.5 percent and a capital structure of 51.8 percent long-term debt, 1.3 percent short-term debt, 46.7 percent common equity and 0.2 percent preferred stock. This recommendation is provisional and may change with updating. It includes the Company's proposed long-term debt, short-term debt and preferred stock amounts, but it reduces the Company's proposed common equity balance. I have done so because Narragansett has artificially increased its actual common equity balance by removing a negative equity account item, Other Comprehensive Income ("OCI"), and I reverse this adjustment.

Although my recommended common equity ratio is somewhat lower than industry averages, it is within the range of industry norms. Moreover, the Company has not adequately supported its decision to remove OCI, which improperly inflates the equity component of capital structure.

Q. THE COMPANY PROPOSES AN IDENTICAL ROE FOR ELECTRIC AND GAS SERVICE. DO YOU OBJECT TO THE USE OF A UNIFORM ROE?

A. No, I believe that approach to be reasonable in this case. This is because both the cost of equity and risk profiles of electric distribution utility service and gas distribution utility service are very similar – with any difference being well within the ranges of the cost of equity model results for electric and gas distribution proxy groups. The actual gas and electric equity cost rates – if not identical – are very similar.

Q. DO YOU AGREE WITH THE COST RATES FOR SHORT AND LONG-TERM DEBT PROPOSED BY MR. HEVERT?

A. Not entirely. Mr. Hevert proposes a short-term cost of debt of 0.8 percent, and I do not object to this estimate. The Company estimates that its embedded cost of long-term debt will be 5.32 percent after the planned issuance of $150 million of new long-term debt. This assumes an all-in cost rate for this planned new debt of 4.85 percent.

I have accepted the 4.85 percent and $150 million of new debt as "placeholders," pending the actual issuance expected to occur later this year. I also accept the Company's position that the high cost "gas legacy" debt should be directly assigned to the gas service for cost of debt/rate of return purposes. This approach leads the Company to calculate a (provisional) 5.11 percent cost of long-term debt for electric service and a 5.90 percent long-term debt cost rate for gas service.

While I provisionally accept 5.11 percent as the electric service cost of debt, the gas service cost of debt of 5.90 percent proposed by the Company has been incorrectly calculated. The correct calculation of the gas cost of debt (again, on a provisional basis) is 5.65 percent, and I employ that figure.

Q. WHAT IS THE BASIS OF YOUR 9.5 PERCENT RECOMMENDATION FOR THE RETURN ON EQUITY?

A. I am relying primarily upon the standard discounted cash flow ("DCF") model applied to three proxy groups: (1) a electric distribution utility companies, (2) a group of natural gas distribution utility companies and (3) a group of vertically-integrated electric utilities very similar to those selected by Mr. Hevert for his DCF studies. My DCF studies use market data from the six months ending June 2012, obtaining a range of 8.5 to 9.9 percent. My recommendation of 9.5 percent is slightly above the midpoint and reasonably reflects this range of evidence. I have attempted to confirm my DCF results and recommendation using the Capital Asset Pricing Model (CAPM) as a check. While the CAPM tends to produce a very wide range of cost of equity results, in my opinion, a reasonable application of this methodology using current market data provides estimates in approximately the 7 to 9 percent range when a reasonable range of data inputs is used. The CAPM midpoint is about 8 percent (or even less). As my testimony explains, the CAPM currently produces cost of equity results that are somewhat lower than normal and should not be given as much weight as it otherwise might be under more normal circumstances.

Mr. Hevert employs an additional methodology, i.e., the Risk Premium. While I don't regard this method as particularly useful or reliable, when Mr. Hevert's data are updated and properly interpreted, they tend to support the reasonableness of my DCF range of results and recommendation.

Q. DO YOU INCLUDE AN ADJUSTMENT FOR FLOTATION EXPENSE?

A. No, there is no indication that any flotation expense has or will in the near future be incurred on behalf of Narragansett to support its equity balance or to provide investment capital. I note that Mr. Hevert also does not include an adder for flotation expense in his cost of equity analysis.

Q. DO YOU CONSIDER NARRAGANSETT TO BE A LOW-RISK UTILITY COMPANY?

A. Yes, very much so, and this is also the clear consensus of credit rating agencies. Narragansett provides monopoly electric and gas distribution utility service in its Rhode Island service territory, subject to the regulatory oversight of this Commission. There is no indication of any material increase in business or financial risk since its last rate case or relative to other utilities in recent years. In Section III of my testimony, I discuss the risk attributes for the Company cited in recent credit rating reports.

Q. PLEASE SUMMARIZE YOUR RECOMMENDED CHANGES CONCERNING RATE OF RETURN.

A. At this time and subject to potential updating, I am recommending the following changes to Mr. Hevert's rate of return:

(1) I have lowered the ROE from the requested 10.75 percent to 9.5 percent, a figure modestly lower than what this Commission approved for electric service in the 2009 rate case.

(2) I have corrected the (provisional) gas service cost of debt from 5.90 to 5.65 percent.

(3) I recommend a lower common equity ratio of 46.7 percent in place of the requested 49.6 percent, reversing Mr. Hevert's adjustment to common equity for OCI.

(4) I note that cost of debt will be updated based on the outcome of the Company's actual long-term debt issue that is expected to take place later this year.

B. <u>Summary of Cost of Equity Study Results</u>

Q. THERE IS A LARGE DIFFERENCE BETWEEN YOUR 9.5 PERCENT ROE AND MR. HEVERT'S 10.75 PERCENT ROE. WHAT ACCOUNTS FOR THIS DIFFERENCE?

A. My 9.5 percent ROE is based upon the application of the standard DCF model to proxy gas and electric distribution utilities. Although Mr. Hevert conducts cost of equity studies, including the use of the DCF model, his 10.75 percent recommendation is significantly higher than his study results.

TABLE 1

Mr. Hevert's Summary Results

Method	Cost of Equity	# Studies	Reference
DCF – Constant Growth	9.63%*	6	Table 10
DCF – Multi Stage	10.38*	6	Table 10
CAPM	10.13	16	Tables 1 (a) and (b)
Equity Risk Premium	10.37	3	Table 1 (a)
Average	10.13%	--	

*DCF summary is based on Mr. Hevert's "mean" or average growth rates.

While Mr. Hevert refuses to assign specific weights to these four methods, his ROE range is 9.63 to 10.37 percent, or an average of 10.13 percent. Moreover, his constant growth DCF study results – the model often relied upon by this and other regulatory commissions – is 9.63 percent. This is only slightly higher than my ROE recommendation and is lower than the currently authorized 9.8 percent. Thus, Mr. Hevert's inflated 10.75 percent recommendation is not supported by his own study results, particularly his constant growth DCF studies.

Q. BASED ON HIS STUDIES, WOULD 10.13 PERCENT BE A REASONABLE ROE AWARD IN THIS CASE?

A. While it would be more reasonable than his 10.75 percent recommendation, in my opinion it would still significantly overstate Narragansett's cost of equity at this time. The reasons include the following:

- Mr. Hevert's results reflect at least in part the risks of generation supply, which are not relevant to Narragansett. The majority of his proxy companies are vertically-integrated electric utilities. His results also include some risk of non regulated operations, although this effect is small.
- Mr. Hevert's Risk Premium and CAPM calculations are based on 30-year Treasury yields that are somewhat overstated relative to current market conditions.
- The most serious error pertains to Mr. Hevert's multi stage DCF studies (10.37 percent), which assume a long-term growth rate of the U.S. economy of nearly 6 percent. This is overly optimistic relative to prevailing expectations of forecasters. Correcting this one flawed parameter would reduce his multi-stage DCF estimate to well below 10 percent.

- Finally, I question whether Mr. Hevert's Risk Premium model is actually a cost of equity method at all.

Correcting these problems, the analytic results would not at this time support a cost of equity finding higher than about 9.5 percent for Narragansett.

Q. WHAT COST OF EQUITY RESULTS DID YOU OBTAIN?

A. Using market data covering the first half of 2012, I obtained the following:

TABLE 2

Mr. Kahal's Cost of Equity Estimates

Study	Range	Midpoint	Source
Electric Distribution DCF	8.5-9.5%	9.0%	Schedule MIK-4
Gas Distribution DCF	8.8-9.8%	9.3%	Schedule MIK-5
Vertically-Integrated Electric DCF	8.9-9.9%	9.4%	Schedule MIK-6
CAPM	6.5-9.3%	8.4%	Schedule MIK-7

My DCF estimates, which are the basis of my ROE recommendation for Narragansett, are in the low to mid 9s. My point value recommendation at this time of 9.5 percent gives some recognition to the sharp reduction since the last case in the utility cost of equity capital, Narragansett's ratemaking capital structure, and the fact that the current authorized return is a higher figure of 9.8 percent.

C. Capital Cost Trends

Q. HAVE YOU EXAMINED GENERAL TRENDS IN CAPITAL COSTS IN RECENT YEARS?

A. Yes. I show the capital cost trends since 2001, through calendar year 2011, on page 1 of Schedule MIK-2. Pages 2, 3 and 4 of that schedule show monthly data for January 2007 through June 2012. The indicators provided include the annualized inflation rate (as measured by the Consumer Price Index), ten-year Treasury yields, 3-month Treasury bill yields and Moody's Single A yields on long-term utility bonds. While there is some fluctuation, these data series show a generally declining trend in capital costs. For example, in the early part of this ten-year period utility bond yields averaged about 8 percent, with 10-year Treasury yields of 5 percent. By 2011, Single A utility bond yields had fallen to 5.1 percent, with ten-year Treasury yields declining to 2.8 percent. Within the past six months, Treasury and utility long-term bond rates have declined even further to near or below the lowest levels in decades.

For the past three years, short-term Treasury rates have been close to zero, with three-month Treasury bills averaging about 0.1 percent. These extraordinarily low rates (which are also reflected in non-Treasury debt instruments) are the result of an intentional policy of the Federal Reserve Board of Governors (the Fed) to make liquidity available to the U.S. economy and to promote economic activity. The Fed has also sought to exert downward pressure on long-term interest rates through its policy of "quantitative easing." Although that program ended this past summer, the Fed announced a continuation of its near-zero short-term interest rate policy at least through 2014. As a result, interest rates have remained low and have trended down and, for at least the near term, this very low interest rate environment is expected to continue.

Q. ARE THERE FORCES CONTRIBUTING TO LOW INTEREST RATES OTHER THAN FED POLICY?

A. Yes. While the decline in short-term rates is largely attributable to Fed policy decisions, the behavior of long-term rates reflects more fundamental economic forces. Factors that drive down long-term bond interest rates include the ongoing weakness of the U.S. and global macro economy, the inflation outlook and even international events. A weak economy (as we have at this time) exerts downward pressure on interest rates and capital costs generally because the demand for capital is low and inflationary pressures are lacking. While inflation measures can fluctuate from month to month, long-term inflation rate expectations presently remain quite low. Europe's Euro-zone continuing sovereign debt crisis probably contributes to lower U.S. interest rates, as U.S. securities are valued as a relative "safe haven" for global capital.

Q. DO LOW LONG-TERM INTEREST RATES IMPLY A LOW COST OF EQUITY FOR UTILITIES?

A. In a very general sense and over time that is normally the case, although the utility cost of equity and cost of debt need not move together in lock step or necessarily in the short run. The economic forces mentioned above that lead to lower interest rates also tend to exert downward pressure on the utility cost of equity. After all, many investors tend to view utility stocks and bonds as alternative investment vehicles for portfolio allocation purposes, and in that sense utility stocks and long-term bonds are related by market forces.

Q. ARE RELATIVE ECONOMIC WEAKNESS AND LOW INFLATION EXPECTED TO CONTINUE?

A. Yes, that appears to be the case. I have consulted the latest "consensus" forecasts published by *Blue Chip Economic Indicators* (Blue Chip), July 10, 2012 edition, a survey compilation of approximately 40 major forecast organizations. The "consensus" calls for real GDP growth of 2.1 percent in 2012 and 2.3 percent in 2013 and inflation (GDP deflator) of 1.8 percent in both 2012 and 2013, respectively. The March 2012 edition of Blue Chip also publishes a consensus ten-year inflation forecast of 2.1 to 2.2 percent per year, almost no change from the near term. Thus, both the near-term and long-term economic outlooks are for sluggish economic growth and low inflation, implying low capital costs.

Q. HAS THE PATTERN BEEN SIMILAR FOR EQUITY MARKETS?

A. As one would expect, equity markets have exhibited far more volatility than bond markets. Following the onset of the financial crisis about three years ago, stock market prices plunged, reaching a bottom in March 2009. Since then, stock prices recovered impressively and the major indexes have largely recovered to pre-crisis levels. The market recovery continued through most of the first half of 2011, but it then began to deteriorate in late July 2011. The second half of 2011 was characterized by significant stock market losses, some recovery and high volatility. The federal debt ceiling debate issue and the subsequent Standard & Poors (S&P) downgrade of Treasury securities may have been initial triggering events for the equity market turmoil during August and September 2011. The larger fundamental concerns of investors, based on reporting by the financial press, include the unraveling of the Euro-zone sovereign debt crisis (and its potential adverse impact on the European banking system) and the expectations by investors of the potential for further weakening in the U.S. economy (and to some extent, the global economy). In the fourth quarter 2011, the stock market recovered, and for 2011 overall the market was flat or provided only very modest returns for investors.

The effects of these economic events on U.S. utilities (such as Narragansett), however, are difficult to interpret. It would seem that the Euro-zone and global economic issues would have little to do directly with U.S. electric and gas utilities such as Narragansett. However, the recent behavior of markets may, in a general sense, reflect heightened equity risk premiums. At the same time, the continuing economic weakness tends to exert downward pressure on capital costs, interest rates and inflation. Thus, despite the turmoil in financial markets, we remain in a generally low capital cost environment for good quality utilities.

Q. HAVE YOU BEEN ABLE TO INCORPORATE THESE RECENT CHANGES IN FINANCIAL MARKETS INTO YOUR COST OF CAPITAL ANALYSIS IN THIS CASE?

A. Yes, to a large extent I have done so. As a general matter, electric and gas utility stocks have been reasonably stable in 2011, and through the first half of 2012, as my testimony demonstrates. The observed 2011 overall stock market volatility was quite significant, but it may turn out to be transitory. While these market events are notable, there is no clear evidence that this recent European and U.S. equity market volatility has adversely affected the utility cost of capital. Dividend yields for utility companies (such as the electric and gas utility companies in my proxy group) have been reasonably stable and the utility long-term cost of debt is at a historic low. At this point, I believe it is reasonable to rely on a most recent six-month average of market data, which has been my past practice. This use of market data over a six-month period fully accounts for the observed equity market volatility, an issue discussed at some length in Mr. Hevert's testimony.

D. Testimony Organization

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. Section III of my testimony explains my proposed corrections to Narragansett's ratemaking capital structure and gas service cost of debt. It also includes a brief discussion of the Company's risk profile as viewed by credit rating agencies. Section IV presents my independent cost of equity studies, i.e., the three DCF studies and the CAPM calculations. Section V is my review and critique of Mr. Hevert's cost of equity studies.

III. CAPITAL STRUCTURE, COST OF DEBT AND BUSINESS RISK

A. Capital Structure

Q. HOW DOES MR. HEVERT DEVELOP NARRAGANSETT'S PROPOSED RATEMAKING CAPITAL STRUCTURE?

A. Mr. Hevert employs Narragansett's actual capital structure at December 31, 2011, which is the end of the test year, and he makes three adjustments. First, he subtracts $725 million of goodwill (presumably resulting from the National Grid merger) from the equity balance. This is a standard adjustment both in this jurisdiction and others to avoid imposing an improper merger cost on customers. Second, he removes from equity the OCI balance (a negative $84.2 million), which has the effect of increasing the equity balance. Third, the Company assumes a $150 million long-term debt issue to take place later this year at a cost of 4.88 percent. All debt proceeds are assumed to be used to reduce short-term debt. Hence, Mr. Hevert increases long-term debt by $150 million and reduces short-term debt by an identical $150 million, resulting in no change to total debt. These three adjustments to the actual year-end capital structure result in proposed ratemaking capital structure of 49.6 percent common equity, 0.2 preferred stock, 1.2 percent short-term debt and 49.0 percent long-term debt. (Source: Schedule RBH-8)

Q. DOES THE COMPANY CONTINUE TO PLAN FOR A $150 MILLION LONG-TERM DEBT ISSUE?

A. Based on the response to DIV 23-5 Elec/Gas, the Company now expects a somewhat larger debt issue, i.e., $200 million. Again, it is assumed that the entire amount of the debt proceeds will be used to extinguish short-term debt (which during 2012 has been increasing). For this reason, the Company suggests in its data response that the increase in the long-term debt issue to $200 million will have only a modest effect on the ratemaking capital structure based on updated June 30, 2012 capitalization.

Q. DOES YOUR RECOMMENDATION ON CAPITAL STRUCTURE TAKE INTO ACCOUNT THIS UPDATE ON THE LONG-TERM DEBT ISSUANCE?

A. No. The Company's data response cited above, which provides an update, was provided on August 21, 2012, and I am still in the process of reviewing it. It would be appropriate to consider this recent update during the rebuttal/surrebuttal phase of this case. Please note that the increase in the planned debt issue to $200 million will also affect the calculation of the embedded cost of long-term debt.

Q. ARE YOU PROPOSING ANY CHANGES AT THIS TIME TO THE COMPANY'S PROPOSED CAPITAL STRUCTURE?

A. Yes. While I can accept the Company's (provisional) adjustment for new long-term debt (and corresponding reduction in short-term debt) and its removal of goodwill, the OCI adjustment of $84.2 million has not been adequately supported. The Company was asked to justify this adjustment in DIV 3-4 Elec/Gas and to cite to any Commission precedents that validate the adjustment. The response states that OCI reflects unrealized gains and losses on pensions and other assets and its removal provides a more accurate representation of the common equity that actually funds long-term operations. The response further states that the Company has previously proposed this adjustment in prior rate cases, but the data response was unable to cite to any Commission approval precedent.

Q. WHY IS THIS RESPONSE NOT A PERSUASIVE SUPPORT FOR THE OCI ADJUSTMENT?

A. In making the OCI adjustment, Mr. Hevert is claiming that the common equity balance is $84.2 million larger than it actually is. This is a fiction because it pretends that this equity capital is supporting "long-term operations" when, in fact, the equity capital does not actually exist and has not been supplied by investors. Moreover, the capital structure and equity balance is ultimately under the control of Company management and the parent company, National Grid USA. If the parent wanted to invest additional equity capital in Narragansett to achieve the capital structure target of 49.6 percent, it can certainly do so. It obviously has chosen not to do so.

The fact that Narragansett has previously proposed this adjustment in prior cases may be true, but this is not relevant. The data response was unable to cite a single instance when this Commission has adopted the adjustment. Certainly, it was not adopted in the Company's 2009/2010 rate case.

Q. WITH THE REMOVAL OF THE OCI ADJUSTMENT, WHAT ARE YOUR CAPITAL STRUCTURE RESULTS?

A. I show my recommended capital structure calculation on page 3 of Schedule MIK-1. I start with the actual balance sheet capital structure at December 31, 2011 and subtract $724.8 million for goodwill from common equity, add $150 million of long-term debt and subtract an identical $150 million from short-term debt. This results in a common equity ratio of 46.74 percent common equity, 0.2 percent preferred stock, 1.3 percent short-term debt and 51.8 percent long-term debt.

Q. IS YOUR RESULTING CAPITAL STRUCTURE WITHIN THE RANGE OF REASONABLENESS?

A. Yes, I believe that it is. I show the common equity ratios for all three of my DCF proxy groups that I employ on Schedule MIK-3. The gas companies average 50.8 percent, the electric distribution companies average 46.2 percent and the integrated electrics average 50.4 percent. Please note that the equity ratios for the two electric utility groups are somewhat overstated because they were calculated by the Value Line Investment Survey excluding short-term debt and current maturities of long-term debt. My 46.74 percent equity ratio is clearly within the range of industry practice. Above all, my recommended capital structure is reasonable because it reflects the actual financial decisions of Company management.

Q. HAS THE COMPANY IDENTIFIED ANY OTHER CORRECTIONS OR UPDATES TO ITS CAPITALIZATION DATA?

A. Yes. On August 21, 2012, the Company supplied the response to DIV 23-7 Elec/Gas which identified certain minor corrections to capitalization and the embedded cost of debt. The response indicated that December 31, 2011 equity capitalization had been slightly overstated and the cost of debt slightly understated (by about 0.1 percent). The response states the Company’s intention to correct these errors and also to include certain debt related expenses in rate base. The Company did not state when it intends to introduce and explain these corrections, but I am assuming it would do so in a supplemental filing or with rebuttal testimony.

At this time, I am reviewing these corrections and will address these and any other corrections as part of the rebuttal/surrebuttal phase of this case, along with any relevant updates.

B. **<u>Cost of Long-Term Debt</u>**

Q. HOW DID THE COMPANY CALCULATE ITS EMBEDDED COST RATES FOR LONG-TERM DEBT?

A. As shown on Schedule RBH-9, Narragansett has $754.3 million of long-term debt (inclusive of the planned debt issuance) with an overall embedded cost rate of 5.32 percent. (As noted previously, the Company just revised this estimate to 5.42 percent after correcting asserted calculation errors per the response to DIV 23-7.) The long-term debt falls into two categories, $700 million of senior notes at a cost rate of 5.11 percent and $54.3 of First Mortgage Bonds (FMBs) that are secured by the gas assets and that historically have been used for gas service rate of return only. The gas FMB cost of debt is much higher at 8.05 percent.

Mr. Hevert sets the electric service cost of debt at the 5.11 percent cost rate based solely on the senior notes. His gas service cost of debt is a blend or weighted average of the 5.11 percent senior note cost rate and the 8.05 percent FMB cost rate, or 5.90 percent. The key to this weighted average calculation is his assumption of how much of the total $754.3 million of long-term debt is gas related. Mr. Hevert assumes 27 percent is gas related and 73 percent is electric related.

Q. DO YOU AGREE WITH MR. HEVERT'S COST OF DEBT CALCULATIONS?

A. Not entirely. To begin with, I am setting aside for now the recent correction set forth in the response to DIV 23-7 and the fact that the new debt issue cost rate is only an assumed value (4.88 percent). That is, these cost rate figures presumably will be updated later in this case. I also have no disagreement with basing the electric service cost rate on the senior notes (i.e., 5.11 percent) and directly assigning the gas FMBs to the gas service cost of debt. My disagreement is with the 27 percent weight that Mr. Hevert attaches to gas service.

The weights assigned to gas versus electric operations for purposes of this rate case should be based upon the gas versus electric rate base. This is because the return on rate base is the means by which a utility recovers its cost of debt (i.e., interest expense) and is how customers are charged for those expenses. As summarized by Mr. Horan, the Company proposes a gas rate base in this case of $370 million and an electric rate base of $575 million, or an approximate 39 percent gas/61 percent electric split.

I have calculated the gas service debt cost rate assuming a 39 percent allocation in place of Mr. Hevert's 27 percent allocation. This results in a 5.65 percent gas service cost of debt, on a provisional basis. Please note that the use of the 5.65 percent gas figure will result in Narragansett obtaining the "correct" overall embedded cost of debt as follows:

$$5.65\% \times 39\% + 5.11\% \times 61\% = 5.32\%$$

That is, the 5.65 percent gas debt cost rate in conjunction with a 5.11 percent electric debt cost rate produces for Narragansett the claimed overall 5.32 percent embedded cost of debt. This assumes that the Company's rate base figures are correct.

Q. DO YOU HAVE ANY COMMENTS ON THE COST OF THE PLANNED NEW DEBT?

A. Yes. At the present time, I am accepting the Company's filed estimate of $150 million and the 4.88 percent cost rate only as placeholders. These placeholder values should be revisited later in this case both for capital structure and cost of debt purposes. The Company recently acknowledged that the debt issue is likely to be closer to $200 million than $150 million.

C. <u>Credit and Risk Assessment</u>

Q. DOES MR. HEVERT DISCUSS NARRAGANSETT'S INVESTMENT RISK?

A. Yes, this is discussed in some detail on pages 52-64 of his testimony. He argues that Narragansett is riskier (or should be perceived as riskier) than his proxy companies (which are most vertically-integrated electric or combination utilities) for several reasons. These include the following assertions:

- Narragansett is "small" compared to his proxy companies, and size is an important risk factor.
- Narragansett is regulated by the Rhode Island Commission, and as a result, is exposed to greater regulatory risk than his proxy companies.
- Narragansett has a large capital spending program, particularly compared to its cash flow from depreciation.

Despite these arguments, Mr. Hevert does not propose a specific risk adjustment to his cost of equity studies to reflect Narragansett's allegedly higher investment risk.

Q. DOES MR. HEVERT CITE TO THE COMPANY'S CURRENT CREDIT RATINGS?

A. Yes. Narragansett is currently rated by both Standard & Poor's (S&P) and Moody's Investor Service (Moody's). The Company has corporate credit ratings of low single A and senior secured debt ratings of medium to strong single A. These are reasonably favorable credit ratings and reflect the Company's very favorable investment risk profile.

S&P regards Narragansett as having an "excellent" business risk position "reflecting its low-risk distribution operations". (S&P report of September 26, 2011.) However, S&P's ratings tend to be based on its overall assessment of the consolidated National Grid. In that respect, S&P notes as credit negatives National Grid's unregulated operations (albeit relatively small) and the parent's "relatively high financial leverage". The overall positive assessment is that Narragansett and the other National Grid subsidiaries benefit from "the strong and predictable cash flows from the group's low operating risk electricity and gas network operations". (Id.)

Moody's has a similarly favorable view of Narragansett's investment risk. Moody's May 2010 report references "the company's favorable business and operating risk profile underpinned by its natural monopoly position and strong cash flow generation from its regulated activities." Moody's also takes into account Narragansett's position as a National Grid subsidiary.

Q. HAS MR. HEVERT PROVIDED ANY PERSUASIVE EVIDENCE THAT NARRAGANSETT IS RISKIER THAN THE PROXY COMPANIES?

A. No, he has not. His discussion of so-called regulatory risk is both subjective and very incomplete, and there is no assessment of how this risk affects Narragansett's cost of equity relative to his proxy companies, if at all. Please note that credit rating agencies clearly take into account a utility's regulatory risk. Notwithstanding their perceptions of this risk, S&P and Moody's provide very favorable business risk assessments of Narragansett, as discussed above. Thus, even if it is true that Narragansett has above average business risk (an assertion which is unclear), it is offset by other factors as discussed in the credit rating reports.

Q. MR. HEVERT CITES TO LANGUAGE FROM RHODE ISLAND'S DECOUPLING ACT THAT HE CLAIMS PRECLUDES A DOWNWARD ADJUSTMENT TO THE COST OF EQUITY FOR THE FAVORABLE "RATEMAKING MECHANISMS" THAT THE ACT PROVIDES. ARE YOU PROPOSING ANY SUCH DOWNWARD ADJUSTMENT?

A. No, I have proposed no such downward adjustment. In fact, my ROE recommendation is slightly higher than the midpoint of my DCF results. The irony here is that it is Mr. Hevert who departs from the results of his own DCF studies by recommending 10.75 percent, a figure well above his midpoint DCF results.

Q. MR. HEVERT CLAIMS THAT NARRAGANSETT'S ALLEGEDLY SMALL SIZE SUPPORTS A RISK ADJUSTMENT TO ITS COST OF EQUITY. DO YOU AGREE?

A. No, and frankly his analysis is absurd and unsupported. The evidence that he cites that size is an equity risk factor pertains entirely or primarily to non regulated companies. He has no evidence that size is a significant risk factor for regulated utilities. Moreover, his assertion is contradicted by his own DCF evidence. I have compared Mr. Hevert's DCF evidence for the gas companies (which are generally smaller companies) with the electric companies (which are generally much larger than the gas companies). The gas DCF results are much lower than the larger electric utilities. My own analysis finds that the two groups are similar, with gas companies being slightly lower. While many factors can affect these DCF results, there is certainly no evidence of a small size cost of equity premium.

It is also absurd to consider Narragansett to be a small company. It is wholly-owned by National Grid USA, which has assets totaling about $39 billion. The point here is that Narragansett contributes to both the size and geographic diversification of National Grid.

Q. MR. HEVERT CITES TO THE RHODE ISLAND DECOUPLING ACT TO SUPPORT HIS POSITION. IS THAT DISCUSSION RELEVANT TO THE SIZE ISSUE?

A. While it is not my intention to offer a legal opinion, the citation in Mr. Hevert's testimony (page 59) merely refers to "the norm of industry standards" and the need to maintain the Company's "financial health" as a stand-alone company. There is nothing in the concepts of "industry norms" or "financial health" that compels, justifies or supports in any way a cost of equity "size" adjustment. Mr. Hevert's reference to the Decoupling Act is misplaced and does not support in any way an upward adjustment to the cost of equity.

Q. MR. HEVERT'S THIRD ARGUMENT PERTAINS TO NARRAGANSETT'S CAPITAL SPENDING. DOES THIS SUPPORT A RISK ADJUSTMENT?

A. No. While I agree with Mr. Hevert that Narragansett's capital spending outlook is significant, there is absolutely no evidence that the Company has any difficulty or faces undue costs raising large amounts of capital on reasonable terms. This is demonstrated by its very successful 2010 debt issuances and its expectation of issuing $150 to $200 million of 30-year debt at a favorable cost rate of 4.88 percent. The credit rating agencies assign the single A rating to Narragansett with full knowledge of the capital spending outlook and Rhode Island regulatory practice.

Perhaps most important of all for this issue, Mr. Hevert provides no comparison of Narragansett's capital spending with that of his proxy companies, which are primarily vertically-integrated electric utilities. For this reason, Mr. Hevert has no basis for claiming that capital spending supports a risk premium for Narragansett as compared to his proxy group DCF results.

Q. DOES MR. HEVERT ACKNOWLEDGE THAT VERTICALLY-INTEGRATED UTILITIES ARE RISKIER THAN DISTRIBUTION-ONLY ELECTRIC UTILITIES?

A. The Division asked Mr. Hevert for risk comparisons of vertically-integrated electrics, unregulated generation and electric/gas utility distribution service in DIV 3-26 Elec/Gas. In his response Mr. Hevert stressed that each situation is unique and must be separately analyzed. Nonetheless, he did offer certain broad generations, noting that:

> Vertically-integrated electric utilities (or regulated companies with electric generation supply) are subject to operating risks to which transmission and distribution utilities may not be exposed.

His response goes on to say that unregulated generation faces market and competitive risks that electric and gas distribution utilities do not face.

While I find Mr. Hevert's response to be very limited and qualified, I believe there is a consensus among analysts that as a general matter regulated generation supply is viewed as riskier than distribution utility service, and unregulated generation even more so. This is clearly the view of credit rating agencies which helps account for Narragansett's favorable credit ratings. The clear implication is that Mr. Hevert's proxy group of vertically-integrated electrics is riskier than Narragansett.

IV. NARRAGANSETT'S COST OF COMMON EQUITY

A. Using the DCF Model

Q. WHAT STANDARD ARE YOU USING TO DEVELOP YOUR RETURN ON EQUITY RECOMMENDATION?

A. As a general matter, the ratemaking process is designed to provide the utility an opportunity to recover its prudently-incurred costs of providing utility service to its customers, including the reasonable costs of financing its used and useful investment. Consistent with this "cost-based" approach, the fair and appropriate return on equity award for a utility is its cost of equity. The utility's cost of equity is the return required by investors (i.e., the "market return") to acquire or hold that company's common stock. A return award greater than the market return would be excessive and would overcharge customers for utility service. Similarly, an insufficient return could unduly weaken the utility and impair its incentives to invest in needed plant and equipment.

Although the *concept* of the cost of equity may be precisely stated, its quantification poses challenges to regulators. The market cost of equity, unlike most other utility costs, cannot be directly observed (i.e., investors do not directly, unambiguously state their equity return requirements), and it therefore must be estimated using analytic techniques. The DCF model is one such prominent and accepted method familiar to analysts, this Commission and other utility regulators.

Q. IS THE COST OF EQUITY A FAIR RETURN AWARD FOR THE UTILITY AND ITS CUSTOMERS?

A. Generally speaking, I believe it is. A return award commensurate with the cost of equity generally provides fair and reasonable compensation to utility investors and normally should allow efficient utility management to successfully finance its operations on reasonable terms. Setting the return on equity equal to a reasonable estimate of the cost of equity also is generally fair to ratepayers.

I recognize that there can be exceptions to this general rule. For example, in some instances, utilities have obtained rate of return adders as a reward for asserted good management performance or lowered returns where performance is subpar. In this case, no request for a management or service quality bonus has been requested by the Company. In addition, the regulator sometimes may take into consideration rate or financial continuity, i.e., avoiding changes in the authorized return that are unduly abrupt. Nonetheless, the principal task at hand is one of measuring the cost of equity.

Q. WHAT DETERMINES A COMPANY'S COST OF EQUITY?

A. It should be understood that the cost of equity is essentially a market price, and as such, it is ultimately determined by the forces of supply and demand operating in financial markets. The cost of equity is also the investor's "discount rate" for the company, i.e., the rate at which the investor "discounts" future earnings or cash flows received in determining the value of the company's stock. In that regard, there are two key factors that determine this price or discount rate. First, a company's cost of equity is determined by the fundamental conditions in capital markets (e.g., outlook for inflation, monetary policy, changes in investor behavior, investor asset preferences, the general business environment, etc.). The second factor (or set of factors) is the business and financial risks of the company in question. For example, the fact that a utility company operates principally as a regulated monopoly, dedicated to providing an essential service (in this case electric and gas distribution utility service), typically would imply very low business risk and therefore a relatively low cost of equity. The Company's relatively strong balance sheet and the favorable business risk profile assessment for providing electric and gas distribution utility service also contribute to its relatively low cost of equity.

Q. DOES MR. HEVERT ADHER TO THESE PRINCIPLES?

A. In general, I believe he does in that he relies to some degree on the DCF methodology to develop his ROE recommendation. However, I must question whether his risk premium study qualifies as a valid cost of equity technique, an issue that I discuss further in Section IV of my testimony. As discussed earlier, his recommendation on ROE in this case also departs from his DCF results.

Q. WHAT METHODS ARE YOU USING IN THIS CASE?

A. I employ both the DCF and CAPM models, applied to three proxy groups of utility companies. I discuss these proxy groups later in this section. However, for reasons discussed in my testimony, I emphasize the DCF model results (as applied to the three utility proxy groups) in formulating my recommendation. It has been my experience that most utility regulatory commissions (federal and state), including Rhode Island, heavily emphasize the use of the DCF model to determine the cost of equity and setting the ROE. As a check (and partly because the Mr. Hevert uses this method), I also perform a CAPM study which also is based on the substantially same utility proxy group companies as used in my DCF study.

Q. PLEASE DESCRIBE THE DCF MODEL.

A. As mentioned, this model has been widely relied upon by the regulatory community, including this Commission. Its widespread acceptance among regulators is due to the fact that the model is market-based and is derived from standard economic/financial theory. The model, as typically used, is also transparent and generally understandable. I do not believe that an obscure or highly arcane model would receive the same degree of regulatory acceptance.

The theory begins by recognizing that any publicly-traded common stock (utility or otherwise) will sell at a price reflecting the discounted stream of cash flows *expected by investors*. The objective is to estimate that discount rate.

Using certain simplifying assumptions that I believe are generally reasonable for utilities, the DCF model for dividend paying stocks can be distilled down as follows:

K_e = (Do/Po) (1 + 0.5g) + g, where:

K_e = cost of equity;

Do = the current annualized dividend;

Po = stock price at the current time; and

g = the long-term annualized dividend growth rate.

This is referred to as the constant growth DCF model, because for mathematical simplicity it is assumed that the growth rate is constant for an indefinitely long time period. While this assumption may be unrealistic in many cases, for traditional utilities (which tend to be more stable than most unregulated companies) the assumption generally is reasonable, particularly when applied to a group of companies.

In addition to using the constant growth model, I note that Mr. Hevert dispenses with this "constancy assumption" by the use of a multi-stage DCF study. Doing so, however, results in a significantly higher cost of equity estimate than when he uses the standard DCF model, as I discuss further in Section V of my testimony.

Q. HOW HAVE YOU APPLIED THIS MODEL?

A. Strictly speaking, the model can be applied only to publicly-traded companies, i.e., companies whose market prices (and therefore market valuations) are transparently revealed. Consequently, the model cannot be applied to Narragansett, which is a wholly-owned subsidiary of National Grid, and therefore a market proxy is needed. In theory, the ultimate parent (National Grid PLC) could serve as that market proxy, since its stock is publically traded, but as a foreign company that would not be practical. Moreover, I am reluctant to rely upon a single-company DCF study (nor has Mr. Hevert), since I believe such studies tend to be less reliable than using "group" data. Neither Mr. Hevert nor I have included National Grid in our respective proxy groups.

In any case, I believe that an appropriately selected proxy group is likely to be far more reliable than a single company study. This is because there is "noise" or fluctuations in stock price or other data that cannot always be readily accounted for in a simple DCF study. The use of an appropriate and robust proxy group helps to allow such "data anomalies" to cancel out in the averaging process.

For the same reason, I prefer to use market data that are relatively current but averaged over a period of six months rather than purely relying upon "spot" market data. It is important to recall that this is not an academic exercise but involves the setting of permanent rates that can be expected to remain in effect for several years. The practice of averaging market data over a period of several months can add stability to the results. It appears that Mr. Hevert employs market time periods that range from one month to six months. In my opinion, six months is preferable since it encompasses a broader range of market data while still being reasonably current.

Q. ARE YOU EMPLOYING THE SAME PROXY COMPANIES AS MR. HEVERT?

A. My proxy companies selected for DCF purposes are very similar to Mr. Hevert, but I have organized them in a somewhat different manner. Mr. Hevert selects three proxy groups: (1) gas utility companies; (b) a group of combination electric/gas utilities; and (c) a group of vertically-integrated electric utilities. Please note that the "combination" companies are all listed as electric utilities by Value Line and most (but not all) are vertically-integrated electrics. Some of Mr. Hevert's proxy companies do have unregulated operations, but he has attempted to screen out those that he considers to have excessive amounts of nonregulated activity.

I have utilized all of Mr. Hevert's proxy companies with two exceptions. I have excluded FirstEnergy and Dominion since both are major players in the unregulated generation market and therefore reflect unregulated generation risks. I do not believe these two exclusions cause a significant change to my DCF results. I have reorganized Mr. Hevert's companies into three groups that reflect their operations: (1) gas utility (similar to Mr. Hevert); (b) electric distribution only; and (3) vertically-integrated electric (which includes the combination companies that have regulated generation). In developing these three groups, I include two companies omitted by Mr. Hevert. Specifically, I add AGL Resources to my gas group and Northeast Utilities to the electric distribution group. In addition, I present my electric distribution data both with and without C.H. Energy, a company presently involved in a pending merger.

Q. PLEASE IDENTIFY YOUR PROXY COMPANIES.

A. I show a listing of the proxy companies used in my three DCF studies on Schedule MIK-3 along with several risk-type indicators for each company. Page 1 of that schedule lists the nine gas distribution utilities that I use. Page 2 of the schedule lists the six companies that operate primarily as electric distribution companies (although they also have substantial gas utility operations as well). Page 3 lists 25 vertically-integrated electric utilities, including the "combination" companies. As is the case with Mr. Hevert, my proxy group companies do have at least some non-utility operations which are viewed as riskier than utility operations (e.g., competitive generation or energy services). I make no specific adjustment at this time to the DCF cost of capital results or to my recommendation for those potentially riskier non-regulated operations. Overall, the non-utility operations for these companies generally are relatively modest and do not unduly distort the task of estimating the utility cost of capital. Nonetheless, the existence of non-utility risk does add to the conservatism of my results and recommendation.

B. <u>Electric Distribution DCF Study</u>

Q. HOW HAVE YOU APPLIED THE DCF MODEL TO THIS GROUP?

A. I have elected to use a six-month time period to measure the dividend yield component (Do/Po) of the DCF formula. Using the Standard & Poor's *Stock Guide*, I compiled the month-ending dividend yields for the six months ending June 2012, the most recent data available to me as of this writing. This time period covers the first half of calendar 2012. During the first quarter of 2012, the overall stock market experienced significant gains, but nonetheless utility stocks were fairly stable. In recent months the broader stock market has declined somewhat from its earlier highs in response to the European debt and economic issues, but these electric utility stocks for this recent six-month period remained stable.

I show these dividend yield data on page 2 of Schedule MIK-4 for each month and each proxy company, January through June 2012. Over this six-month period the proxy group average dividend yields were relatively stable, ranging from a low of 4.32 percent in June to a high of 4.52 percent in May 2012, averaging 4.42 percent for the full six months. The results that I cite to exclude C.H. Energy, and with that company the dividend yield average would be slightly lower.

For DCF purposes and at this time, I am using a proxy group dividend yield of 4.42 percent.

Q. IS 4.42 PERCENT YOUR FINAL DIVIDEND YIELD?

A. Not quite. Strictly speaking, the dividend yield used in the model should be the value the investor expects to receive over the next 12 months. Using the standard "half year" growth rate adjustment technique, the DCF adjusted yield becomes 4.5 percent. This is based on assuming that half of a year growth is 2.25 percent (i.e., a full year growth is 4.5 percent). The adjusted yield calculation is 4.42% x 1.0225 = 4.52%.

Q. HOW DOES YOUR DIVIDEND YIELD ADJUSTMENT COMPARE TO MR. HEVERT'S DIVIDEND YIELD ADJUSTMENT METHOD FOR HIS DCF STUDIES?

A. They are very similar. Mr. Hevert uses a different time frame for his market prices (late 2011 and early 2012), but he also employs the standard "0.5g" method to adjust the current dividend yield.

Q. HOW HAVE YOU DEVELOPED YOUR GROWTH RATE COMPONENT?

A. Unlike the dividend yield, the investor growth rate cannot be directly observed but instead must be inferred through a review of available evidence. The growth rate in question is the *long-run* dividend per share growth rate, but analysts frequently use earnings growth as a proxy for (long-term) dividend growth. This is because in the long-run earnings are the ultimate source of dividend payments to shareholders, and this is likely to be particularly true for a large group of utility companies.

One possible approach is to examine historical growth as a guide to investor expected future growth, for example the recent five-year or ten-year growth in earnings, dividends and book value per share. However, my experience with utilities in recent years is that these historic measures have been very volatile and are not necessarily reliable as prospective measures. This is due in part to extensive corporate or financial restructuring. The DCF growth rate should be prospective, and one useful source of information on prospective growth is the projections of earnings per share (typically five years) prepared by securities analysts. Mr. Hevert relies very heavily on securities analyst earnings projections as the basis for his DCF growth rates in his constant growth DCF studies. I agree with Mr. Hevert that it warrants substantial emphasis though not exclusive emphasis.

Q. PLEASE DESCRIBE THE ANALYST EARNINGS GROWTH RATE EVIDENCE THAT YOU HAVE EMPLOYED.

A. Schedule MIK-4, page 3 presents five available and well-known public sources of projected earnings growth rates. Four of these five sources -- YahooFinance, MSNMoney, Reuters and CNNfn -- provide averages from securities analyst surveys conducted by or for these organizations (typically they report the mean or median value). The fifth, Value Line, is that organization's own estimates and is readily available publically on a subscription basis. Value Line publishes its own projections using annual average earnings per share for a base period of 2009-2011 compared to the annual average for the forecast period of 2015-2017.

As this schedule shows, the growth rates for individual companies vary somewhat among the five sources, but the group averages are very similar. These proxy group averages are 5.1 percent for CNNfn, 4.3 percent for YahooFinance, 4.7 percent for MSNMoney, 4.6 percent for Reuters and 5.4 percent for Value Line. Thus, the range of growth rates among the five sources is 4.3 to 5.4 percent. The average of these five sources is 4.8 percent, and I have used these results (along with other evidence) in obtaining a reasonable expected growth range for the group of 4.0

to 5.0 percent. Please note that these figures exclude C.H. Energy. The proxy group average with C.H. Energy would be slightly lower.

Q. IS THERE ANY OTHER EVIDENCE THAT SHOULD BE CONSIDERED?

A. Yes. There are a number of reasons why investor expectations of long-run growth could differ from the limited, five-year earnings projections prepared by securities analysts. Consequently, while securities analyst estimates should be considered and given significant weight, these growth rates should be subject to a reasonableness test and corroboration, to the extent feasible.

On Schedule MIK-4, page 4 of 5, I have compiled three other measures of growth published by Value Line, i.e., growth rates of dividends and book value per share and the long-run retained earnings growth. (Retained earnings growth reflects the growth over time one would expect from the reinvestment of retained earnings, i.e., earnings not paid out to shareholders as dividends.) As shown on this schedule, these growth measures for the proxy companies tend to be similar to or lower than the analyst earnings growth projections. For the five proxy companies (excluding C.H. Energy), dividend growth averages 2.7 percent, book value growth averages 5.8 percent, and earnings retention growth averages 3.7 percent.

Some analysts and regulators favor the use of earnings retention growth (often referred to as "sustainable growth"), which Value Line indicates to be 3.7 percent (for the proxy companies). This method has been relied upon in the past by this Commission. However, at least in theory, the sustainable growth rate also should include "an adder" to reflect potential future earnings growth contribution from issuing new common stock at prices above book value (referred to as "external growth" or the "s x v" factor). In practice, this factor is difficult to reliably estimate since future stock issuances of companies over the long-term are an unknown, and there is little reliable information on this factor for investors. Consequently, any growth from stock issuance element would be speculative. Nonetheless, I have estimated this "external growth" factor using Value Line projections for these proxy companies based on the growth rate (through 2015-2017) in shares outstanding, along with the current ("recent") stock price premium over book value. For these five companies, the external growth rate calculated in this manner averages about 0.2 percent. The sum of "internal" or earnings retention growth factor (i.e., 3.7 percent) and the "external" growth rate factor (i.e., 0.2 percent) is 3.9 percent.

Given this estimate of 3.9 percent for the sustainable growth rate and 4.8 percent for analyst earnings projections, a reasonable and conservatively high DCF growth rate range is approximately 4.0 to 5.0 percent which appropriately reflects uncertainty concerning investor expectations.

Q. WHAT IS YOUR DCF CONCLUSION?

A. I summarize my DCF analysis on page 1 of Schedule MIK-4. The adjusted dividend yield for the six months ending June 2012 is 4.5 percent for this group. Available evidence would support a long-run growth rate in the range of approximately 4.0 to 5.0 percent, as explained above. Summing the adjusted yield and growth rate range produces a total return range of 8.5 to 9.5 percent, and a midpoint result of 9.0 percent.

Q. ARE YOU INCLUDING IN YOUR RECOMMENDATION A COST ADDER FOR FLOTATION EXPENSE?

A. No, and Mr. Hevert also has not included such an adjustment. Under certain circumstances, it can be appropriate to reflect in the authorized return on equity an "adder" to permit the utility an opportunity to recover the expenses associated with issuing new common stock. This is principally the underwriters fee charged by investment bankers for conducting a public issuance along with any related legal and regulatory expenses. In the case of Narragansett (and its parent, National Grid), there is no indication of flotation expenses in the recent past or prospectively to be recovered, and therefore a flotation adjustment is not needed.

C. Gas Utility DCF Study

Q. HOW HAVE YOU APPROACHED YOUR GAS UTILITY DCF STUDY?

A. I used the same procedures as I used in the electric distribution utility study. My proxy group consists of all companies listed as gas utility in the Vale Line data base with two exceptions. Specifically, I excluded NiSource, which in addition to being a gas utility is also a vertically-integrated electric utility, and UGI. This latter company is a combination gas/electric utility with extensive unregulated propane operations. Mr. Hevert also excludes these two companies. My gas proxy group consists of nine companies shown on Schedule MIK-3, page 1.

Q. PLEASE DESCRIBE YOUR ANALYSIS.

A. The details of the gas utility DCF study are shown on Schedule MIK-5. Page 2 of that schedule provides the dividend yields for the nine companies for January-June 2012. This averages 3.73 percent, ranging from 3.57 to 3.90 percent during the six months.

Page 3 of that schedule provides the securities analyst growth rate projections, which average 4.62 percent.[2] The five sources range from 4.09 percent (CNN) to 4.94 percent (Value Line). Page 5 presents Value Line growth rate projections for the group for dividends per share, book value per share and earnings retention. These growth rates are similar to securities analysts growth rates, ranging from 4.0 percent

[2] Please note that one source, Yahoo Finance, publishes a negative growth rate for AGL Resources. This figure is both unusual and anomalous given that the other four sources report positive growth rates. The average growth rate that I report excludes this anomalous value, which may be in error.

to 5.2 percent. Finally, page 6 of this schedule provides the fundamental growth rate analysis, which finds a growth rate for the proxy group of 6.1 percent, i.e., stock issuance growth of 0.86 percent plus earnings retention growth of 5.2 percent.

Based on the foregoing growth rate evidence, I have adopted a reasonable growth rate range of 5.0 to 6.0 percent.

Q. WHAT IS YOUR OVERALL DCF RESULT?

A. I summarize my gas utility DCF analysis on page 1 of Schedule MIK-5. I start with a six month dividend yield for the group of 3.73 percent, which I adjust upward to 3.8 percent. I combine the dividend yield of 3.8 percent with the growth rate range of 5.0 to 6.0 and thereby obtain a cost of equity range of 8.8 to 9.8 percent, and a midpoint of 9.3 percent. This midpoint value is slightly below my recommendation for Narragansett of 9.5 percent.

Q. MR. HEVERT EXCLUDES AGL RESOURCES. HOW WOULD THAT EXCLUSION AFFECT YOUR DCF STUDY RESULTS?

A. Excluding AGL Resources would very slightly reduce my DCF cost of equity result, perhaps by 0.1 percent or less. This is because AGL Resources has a dividend yield somewhat above the group average, i.e., 4.53 percent versus 3.73 percent.

D. <u>Vertically-Integrated Electric Utility DCF Study</u>

Q. HOW HAVE YOU APPROACHED YOUR DCF STUDY OF THE VERTICALLY-INTEGRATED ELECTRIC UTILITIES?

A. I have used the same basic procedures as I used in the electric and gas distribution utility studies. In this case, I used 25 of the 27 vertically-integrated electric utilities selected by Mr. Hevert (including the vertically-integrated electrics that also have gas operation). I have conducted this study to broaden the range of evidence available to the Commission and so that my DCF results can be compared directly with Mr.

Hevert's DCF results. In fact, these companies may not be the most appropriate proxy for Narragansett because their cost of equity is adversely affected (i.e., increased) by the business risks associated with generation supply, risks that Narragansett customers should not pay for in their distribution rates.

I provide a listing of these customers on page 3 of Schedule MIK-3.

Q. PLEASE DESCRIBE YOUR ANALYSIS.

A. As with the other two studies, I compile the dividend yields for each company on page 2 of Schedule MIK-6. For the period January-June 2012, this averages to 4.28 percent. I then adjust this forward to 4.4 percent to account for half a year of growth. Pages 3, 4 and 5 of Schedule MIK-6 present the growth rate evidence. The securities analyst projections of earnings (page 3 of that Schedule) indicate long-term growth for the proxy group ranging from 4.3 percent for CNN to 6.0 percent for Value Line. The growth rates for the five sources average to 4.88 percent. Please note that this includes an anomalous negative value for one company, Ameren. Excluding Ameren, the proxy group average would be 5.2 percent. (It appears that Mr. Hevert has excluded the negative Ameren values in his study.)

The Value Line growth rate projections on page 5 of this schedule are somewhat lower, ranging from 3.8 to 4.3 percent. Page 6 of this schedule presents the fundamental, or br + sv growth projections. This analysis produces a proxy group growth rate estimate of 4.6 percent.

Based on this evidence, I have selected a DCF growth rate range of 4.5 to 5.5 percent.

Q. WHAT IS YOUR DCF FINDING FOR THE VERTICALLY-INTEGRATED ELECTRIC PROXY GROUP?

A. The summary is shown on page 1 of Schedule MIK-6. I combine an adjusted dividend yield of 4.4 percent with a growth rate range of 4.5 to 5.5 percent, obtaining a cost of equity range of 8.9 to 9.9 percent. The midpoint of this range is 9.4 percent.

E. <u>The CAPM Analysis</u>

Q. PLEASE DESCRIBE THE CAPM MODEL.

A. The CAPM is a form of the "risk premium" approach and is based on modern portfolio theory. Based on my experience, the CAPM is the cost of equity method most often used in rate cases after the DCF method, and it is one of the cost of equity methods used in this case by Mr. Hevert.

According to this model, the cost of equity (K_e) is equal to the yield on a risk-free asset plus an equity risk premium multiplied by a firm's "beta" statistic. "Beta" is a firm-specific risk measure which is computed as the movements in a company's stock price (or market return) relative to contemporaneous movements in the broadly defined stock market (e.g., the S&P 500 or the New York Stock Exchange Composite). This measures the investment risk that cannot be reduced or eliminated through asset diversification (i.e., holding a broad portfolio of assets). The overall market, by definition, has a beta of 1.0, and a company with lower than average investment risk (e.g., a utility company) would have a beta below 1.0. The "risk premium" is defined as the expected return on the overall stock market minus the yield or return on a risk-free asset.

The CAPM formula is:

K_e = $R_f + \beta (R_m - R_f)$, where:

K_e = the firm's cost of equity

R_m = the expected return on the overall market

R_f = the yield on the risk free asset

β = the firm (or group of firms) risk measure.

Two of the three principal variables in the model are directly observable – the yield on a risk-free asset (e.g., a Treasury security yield) and the beta. For example, Value Line publishes estimated betas for each of the companies that it covers, and these betas are widely used by rate of return witnesses, including Mr. Hevert, although he also uses Bloomberg betas. The greatest difficulty, however, is in the measurement of the expected stock market return (and therefore the equity risk premium), since that variable cannot be directly observed.

While the beta itself also is "observable," different investor services provide differing calculations of betas depending on the specific procedures and methods that they use. These differences can have material impacts on the CAPM results.

Q. HOW HAVE YOU APPLIED THIS MODEL?

A. For purposes of my CAPM analysis, I have used a long-term (i.e., 30-year) Treasury yield as the risk-free return along with the average beta for the gas and electric utility proxy groups. (See Schedule MIK-3, pages 1-3, for the company-by-company betas.) In last six months, long-term (i.e., 30-year) Treasury yields have averaged approximately 3.0 percent, and the currently-published Value Line betas for my gas and electric utility proxy groups average about 0.70. Finally, and as explained below, I am using an equity risk premium range of 5 to 8 percent, although I also provide calculations using a higher risk premium (i.e., 9 percent) as a sensitivity test.

Using these data inputs, the CAPM calculation results are shown on page 1 of Schedule MIK-5. My low-end cost of equity estimate uses a risk-free rate of 3.0 percent, a proxy group beta of 0.73 and an equity risk premium of 5 percent.

$$K_e = 3.0\% + 0.70\ (5.0\%) = 6.5\%$$

The upper end estimate uses a risk-free rate of 3.0 percent, a proxy group beta of 0.73 and an equity risk premium of 8.0 percent.

$$K_e = 3.0\% + 0.70\ (8.0\%) = 8.6\%$$

Thus, with these inputs the CAPM provides a cost of equity range of 6.5 to 8.6 percent, with a midpoint of 7.6 percent. The CAPM analysis produces a midpoint result significantly lower than the range of results obtained for my gas and electric utility proxy groups DCF analyses, but I have not placed reliance on the CAPM returns in formulating my return on equity recommendation in this case. This is due to the unusual behavior of Treasury bond markets (the recent "flight to quality problem"), and with the stock market turmoil during the past year, it is difficult to assess equity risk premiums at this time.

Q. WHAT RESULT WOULD YOU OBTAIN USING A MARKET RISK PREMIUM THAT EXCEEDS YOUR 8 PERCENT UPPER END?

A. On Schedule MIK-7, I present a sensitivity case which uses a very high 9 percent risk premium value. In conjunction with a proxy group beta of 0.70 and a 3.0 percent Treasury bond yield, the CAPM produces:

$$K_e = 3.0\% + 0.70\ (9.0\%) = 9.3\%$$

While I view the 9.0 percent market risk premium estimate as potentially excessive, given current data on long-term Treasury yields and electric utility betas (from Value Line), the CAPM using this very high risk premium value produces a return of 9.3 percent. This high end sensitivity estimate is close to but slightly lower than recommendation of 9.5 percent.

Q. WHAT MARKET RISK PREMIUM DID MR. HEVERT USE?

A. Mr. Hevert appears to employ a market risk premium range of 8.5 to 10.0 percent in his CAPM calculations. While the 8.5 percent is close to the upper end of my range, the 10.0 percent figure (which implies a long-term stock market rate of return of about 13 percent) seems unrealistic and overly optimistic. This figure appears to be out of line with expert opinion on the risk premium and expected returns on stocks.

Despite my disagreement, I have calculated the CAPM cost of equity based on Mr. Hevert's risk premium figures.

$$K_e = 3.0\% + 0.70\ (8.5\%) = 9.0\%$$

$$K_e = 3.0\% + 0.70\ (10.0\%) = 10.0\%$$

Mr. Hevert's market risk premium range would imply a CAPM cost of equity range of 9.0 to 10.0 percent, or a midpoint of 9.5 percent.

Q. IT APPEARS THAT A KEY ELEMENT IN YOUR CAPM STUDY IS YOUR EQUITY MARKET RETURN RISK PREMIUM OF 5 TO 8 PERCENT. HOW DID YOU DERIVE THAT RANGE?

A. There is a great deal of disagreement among analysts regarding the reasonably expected market return on the stock market as a whole and therefore the risk premium. In my opinion, a reasonable overall stock market risk premium to use would be about 6 to 7 percent, which today would imply an overall stock market return of about 9.0 to 10.0 percent. Due to uncertainty concerning the true market return value, I am employing a broad range of 5 to 8 percent as the overall market rate of return, which would imply a market equity return of roughly 8 to 11 percent for the overall stock market.

Q. DO YOU HAVE A SOURCE FOR THAT RANGE?

A. Yes. The well-known finance textbook by Brealey, Myers and Allen (*Principles of Corporate Finance*) reviews a broad range of evidence on the equity risk premium. The authors of the risk premium literature conclude:

> Brealey, Myers and Allen have no official position on the issue, but we believe that a range of 5 to 8 percent is reasonable for the risk premium in the United States. (Page 154)

My "midpoint" risk premium of roughly 6.5 percent falls well within that range.

There is one important caveat to consider here regarding the 5 to 8 percent range that the authors believe is supported by the literature. It appears that the 5 to 8 percent range is specified relative to short-term Treasury yields, not relative to long-term (i.e., 30-year) Treasury yields. At this time, the application of the CAPM using short-term Treasury yields would not be meaningful because those yields within the past year have approximated zero. It therefore could be argued that the 5 to 8 percent range of Brealy *et al*. is overstated if a long-term Treasury yield is used as the risk-free rate.

V. REVIEW OF MR. HEVERT'S COST OF EQUITY ANALYSIS

A. Mr. Hevert's Recommendation

Q. HOW HAS MR. HEVERT DEVELOPED HIS 10.75 PERCENT ROE RECOMMENDATION?

A. Mr. Hevert presents cost of equity study results using four methodologies: (1) constant growth DCF, (2) multi-stage DCF, (3) CAPM and (4) Equity Risk Premium. As I mentioned earlier in my testimony, his study results average to about 10.1 percent if each of the four methods is assigned equal weight. The method providing the lowest cost of equity method is the constant growth DCF (9.63 percent using his "mean" or average growth rates), the method most frequently relied upon in the past by this Commission.

Mr. Hevert, however, makes it clear that he does not assign specific weights to the various methods. Instead, he reviews these results and then considers Narragansett's risk attributes relative to his proxy companies. Based on this review, he finds 10.75 percent to be a reasonable ROE point value for Narragansett. The 10.75 percent is a figure within his identified range of 10.5 to 11.25 percent, but the source of this range is also unclear.

It is a challenge to review Mr. Hevert's cost of equity testimony due in part to its complexity and in part to the fact that his ROE recommendation (and even his range) cannot be tied to his study results.

Q. MR. HEVERT'S ROE RECOMMENDATION EXCEEDS HIS PROXY GROUP COST OF EQUITY RESULTS. IS THIS REASONABLE?

A. No, it is not reasonable. Mr. Hevert would have us believe that Narragansett is a risky company with a cost of equity exceeding that of his proxy group. This is not correct. While Narragansett is probably similar in risk to his gas group, it is less (not more) risky than his two electric groups which are composed primarily of vertically-integrated electric utilities and therefore are exposed to the risks of generation service. For example, when Mr. Hevert obtains constant growth DCF estimates averaging 9.63 percent for his proxy companies, this should be considered a high end estimate for Narragansett.

B. The Multi-Stage DCF Study

Q. MR. HEVERT OBTAINS MUCH HIGHER COST OF EQUITY ESTIMATES USING HIS MULTI-STAGE DCF AS COMPARED TO HIS CONSTANT GROWTH DCF STUDY. WHY IS THAT?

A. The two-stage or multi-stage DCF model is much more complex and less intuitive than the constant growth DCF model, and for that reason is not as widely used in regulatory proceedings. That said, the model is conceptually valid and can provide useful insights under some circumstances. For example, if there is reason to believe a company's earnings growth pattern will change substantially over time, the multi-stage model could produce more realistic cost of equity estimates.

In this case, I find Mr. Hevert's multi-stage analysis to be opaque as compared to his more standard, constant growth DCF study. His constant growth study relies upon verifiable market data and published securities analyst forecasts – not Mr. Hevert's subjective opinion or unverifiable assumptions. Reliance on securities analysts earnings forecasts for DCF purposes can and has been criticized, but it is at least clear where the DCF data inputs come from. By comparison, the multi-stage study to some degree employs inputs based on Mr. Hevert's subjective judgment which may have little to do with investor expectations. As I will show, Mr. Hevert is far more optimistic than mainstream economic forecasters, which causes an overstatement of the cost of equity.

Q. WHAT ARE THE SOURCES OF THE GROWTH RATE INPUTS TO HIS MULTI-STAGE MODEL?

A. The model employs three growth rates. The first stage is based on securities analyst growth rates similar to his constant growth DCF study. The second stage is a transition to the third or final stage and uses assumptions based on a generic or industry average dividend payout. The third stage, or the long-term growth path, is particularly crucial in his study. For the third stage, he assumes that earnings/dividends per share for the proxy companies will grow at the same rate as the U.S. economy, referred to as nominal Gross Domestic Product (U.S. GDP). Thus, to implement his model, he requires a forecast of nominal U.S. GDP that will prevail in the third stage.

For this crucial "stage three" parameter he selects a growth rate of 5.77 percent. He bases this assumed figure on historic real growth in the U.S. economy since 1929 and his assumed outlook for inflation. This raises three questions. The first is how important is this growth rate assumption for his cost of equity results from this model? The second question is, do investors expect electric utility earnings/dividend growth in the long run to approximate U.S. economic growth? The third question is, has Mr. Hevert employed a reasonable assumption for long-run economic growth, i.e., "reasonable" meaning in line with investor expectations?

Q. PLEASE ADDRESS THE FIRST QUESTION. HOW SENSITIVE IS THE DCF COST OF EQUITY TO THE LONG-TERM GROWTH RATE ASSUMPTION?

A. Fortunately, this assumption is easily testable. DIV 23-8 Elec/Gas asked Mr. Hevert to rerun his model decrementing the long-term U.S. growth rate assumption by one percentage point from 5.77 percent to 4.77 percent. Recall that his original study produced a cost of equity ("mean" scenario) averaging about 10.4 percent. The data response indicated that the mean DCF cost of equity would be about 9.6 percent if the lower U.S. GDP growth rate is assumed. That is, a 1.0 percentage point reduction in the Stage Three growth rate reduces the calculated cost of equity by nearly 0.8 percentage points. This reveals that Mr. Hevert's U.S. GDP growth rate assumption is crucial.

Q. PLEASE ADDRESS THE SECOND QUESTION, DO INVESTORS EXPECT GAS AND ELECTRIC UTILITY EARNING'S GROWTH TO TRACK U.S. ECONOMIC GROWTH IN THE LONG-RUN?

A. That is possible, but this question cannot be answered with certainty. The problem here is that utilities tend to be a relatively slow growing sector, as compared to U.S. industry generally, and for that reason investors may expect utility earnings in the long-run to grow more slowly than the overall U.S. economy. I believe this to be an important caveat associated with Mr. Hevert's multi-stage DCF model.

Q. THE THIRD QUESTION PERTAINS TO THE APPROPRIATENESS OF MR. HEVERT'S 5.77 PERCENT U.S. GDP GROWTH RATE. IS THIS A REASONABLE ASSUMPTION?

A. No. Obviously no one knows for certain how rapidly the U.S. economy will grow in future years, but Mr. Hevert's 5.77 percent is out of line with expert opinion, and therefore, in all likelihood investor opinion. The well-known publication <u>Blue Chip Economic Indicators</u> publishes consensus forecasts on a range of economic variables, including nominal U.S. GDP growth, twice per year in March and October. The forecasts that it publishes are surveys of approximately 40 major economic forecasting organizations, with the average of the survey response referred to as the "consensus". Blue Chip's latest (March 2012) "consensus" forecast of nominal U.S. GDP annualized growth is as follows:

2012	3.9%
2013	4.1
2014-2018	5.1 (range: 4.3 to 5.9%)
2019-2023	4.7 (range: 4.1 to 4.7%)

The "consensus" outyear growth rate (in nominal terms) for the U.S. economy through 2023 is 4.7 percent, as compared to Mr. Hevert's assumed value of 5.8 percent, or more than a full percentage point lower. It is also notable that forecasters are anticipating some slowing in the pace of economic growth (from 5.1 to 4.7 percent per year) after 2018. This gradual slowing may be due to anticipated demographic changes such as an aging population, factors that Mr. Hevert has not considered.

Q. WHAT DOES THE BLUE CHIP CONSENSUS FORECAST IMPLY FOR THE RESULTS OF THE MULTI STAGE DCF MODEL?

A. As the Company's data response demonstrates, correcting the assumption on U.S. economic growth to reflect forecasters' consensus would reduce the cost of equity estimate from about 10.4 to 9.6 percent – consistent with Mr. Hevert's constant growth DCF results and close to my recommendation. Due to the issues with the multi stage model and controversy over forecasting long-term U.S. GDP growth, I do not recommend reliance on this model.

C. **Mr. Hevert's Equity Risk Premium Model**

Q. PLEASE DESCRIBE DR. HEVERT'S RISK PREMIUM MODEL.

A. Mr. Hevert has developed a simple econometric model (with separate equations for gas and electric) that "explains" the equity risk premium as a function of contemporaneous interest rates (i.e., defined as 30-year Treasury bond yields). The model is estimated using simple regression from a time series of data extending from 1992 to 2012. The relationship is inverse in that the higher the interest rate at any given point in time, the lower is the equity risk premium, and vice versa. Thus, in times like today, with rock bottom interest rates, the model implies that we should expect to see a very high equity risk premium. That is the message from his model.

The key to the entire analysis is the definition of the risk premium. He calculates his historic risk premium data series as the average state commission allowed return on equity in a given calendar quarter minus the prevailing yield on 30-year Treasury bonds in that same quarter. In other words, his model is based on historical regulatory decisions and only partially on market data.

Q. WHAT RESULTS DID HE OBTAIN USING HIS MODEL?

A. Mr. Hevert selects Treasury bond yields of 3.16, 3.42 and 5.30 percent, and with his model he calculates the risk premium cost of equity of 9.92 to 10.80 percent (gas) and 10.11 to 10.94 percent (electric). Since 30-year Treasury bond yields have declined somewhat since he conducted his study, his risk premium cost of equity results using this model today would be slightly lower than even the bottom end of his range, i.e., below 10 percent. This is well below his 10.75 percent recommendation.

Q. SHOULD HIS MODEL BE ACCEPTED?

A. No, it should not be relied upon for setting Narragansett's allowed cost of equity, as it has a number of shortcomings. The most serious problem is that commission allowed returns cannot be assumed to be the same thing as the market cost of equity, although they may be related to the cost of equity in some approximate way. Thus, this is not necessarily a market cost of equity methodology. In a sense, this method is not much different than saying the Rhode Island Commission should simply adopt the average electric and gas ROE from other state commission decisions (albeit adjusted for some percentage of the change in interest rates since those decisions were issued). There may be merit in considering the decisions of other commissions, but it cannot be considered to be a true cost of equity method.

There are also a number of technical or econometric shortcomings of the model. Any valid econometric model must be supported by a convincing underlying theory. In this case, why does the interest rate "determine" the risk premium, and why should this relationship be inverse? If a convincing, logical theory cannot be supplied (which in this case it has not been), then the model cannot be accepted – particularly for such an important task as establishing the authorized return on investment. Absent an accepted supporting explanation, the estimated model may simply be spurious – merely a statistical correlation.

Given that this model is based on regulatory decisions and not directly on market data, what I believe it really shows is that there may be continuity or gradualism considerations in state commission ROE decisions. That is, as the cost of capital has declined over the years, this is not instantaneously reflected in commission ROE rulings but instead takes place with a lag or only gradually. This may be particularly true in settled cases. This would explain the inverse relationship observed in Mr. Hevert's model.

In essence, Mr. Hevert, at best, has developed a model that may be attempting to describe the behavior of utility regulators, but not capital market behavior.

Q. PLEASE COMMENT ON MR. HEVERT'S TREASURY INTEREST RATES.

A. Mr. Hevert first calculates the cost of equity using this model based on prevailing 30-year Treasury rates as of the time he prepared his testimony, 3.16 percent. This produces a cost of equity of about 10 percent (i.e., 9.92 percent gas and 10.11 percent electric). As of mid 2012, 30-year Treasury rates are actually below 3.0 percent. Mr. Hevert also calculates the cost of equity using his model assuming forecasted future interest rates of 3.42 percent (over the next year) and 5.3 percent (the next ten years). In other words, he makes the inappropriate assumption that long-term interest rates and therefore Narragansett's cost of equity will increase over time.

This assumption of rising interest rates so far has been proven to be wrong. That is, the prevailing trend has been one of falling, not rising interest rates. It is particularly inappropriate to base a recommended ROE for Narragansett based on the questionable assumption that the cost of equity in future years will be significantly higher than it is today. Such speculation is poor ratemaking practice and is even inconsistent with market evidence.

If this model is to be relied upon at all (and I recommend that it not be), then a reasonable estimate of the current Treasury rate should be used – about 3 percent, not the fictitious higher interest rates.

Q. DOES YOUR OBJECTION TO THE USE OF OVERSTATED TREASURY INTEREST RATES ALSO APPLY TO MR. HEVERT'S CAPM STUDIES?

A. Yes. For those studies, Mr. Hevert also uses Treasury yields of 3.16 and 3.42 percent as the "risk free" rate. The use of more current, actual Treasury yields (i.e., 3.0 percent or less) would lower his reported CAPM results.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

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APPENDIX A

STATEMENT OF QUALIFICATIONS OF MATTHEW I. KAHAL

MATTHEW I. KAHAL

Since 2001, Mr. Kahal has worked as an independent consulting economist, specializing in energy economics, public utility regulation and utility financial studies. Over the past three decades, his work has encompassed electric utility integrated resource planning (IRP), power plant licensing, environmental compliance and utility financial issues. In the financial area he has conducted numerous cost of capital studies and addressed other financial issues for electric, gas, telephone and water utilities. Mr. Kahal's work in recent years has shifted to electric utility restructuring, mergers and various aspects of regulation.

Mr. Kahal has provided expert testimony on more than 350 occasions before state and federal regulatory commissions and the U.S. Congress. His testimony has covered need for power, integrated resource planning, cost of capital, purchased power practices and contracts, merger economics, industry restructuring and various other regulatory and public policy issues.

Education:

B.A. (Economics) - University of Maryland, 1971.

M.A. (Economics) - University of Maryland, 1974.

Ph.D. candidacy - University of Maryland, completed all course work and qualifying examinations.

Previous Employment:

1981-2001 - Exeter Associates, Inc. (founding Principal, Vice President and President).

1980-1981 - Member of the Economic Evaluation Directorate, The Aerospace Corporation, Washington, D.C. office.

1977-1980 - Economist, Washington, D.C. consulting firm.

1972-1977 - Research/Teaching Assistant and Instructor, Department of Economics, University of Maryland (College Park). Lecturer in Business and Economics, Montgomery College.

Professional Work Experience:

Mr. Kahal has more than thirty years experience managing and conducting consulting assignments relating to public utility economics and regulation. In 1981, he and five colleagues founded the firm of Exeter Associates, Inc. and for the next 20 years he served as a Principal and corporate officer in the firm. During that time, he supervised multi-million dollar support contracts with the State of Maryland and directed the technical work conducted both by Exeter professional staff and numerous subcontractors. Additionally, Mr. Kahal took the lead role at Exeter in consulting to the firm's other governmental and private clients in the areas of financial analysis, utility mergers, electric restructuring and utility purchase power contracts.

At the Aerospace Corporation, Mr. Kahal served as an economic consultant to the Strategic Petroleum Reserve (SPR). In that capacity he participated in a detailed financial assessment of the SPR, and developed an econometric forecasting model of U.S. petroleum industry inventories. That study has been used to determine the extent to which private sector petroleum stocks can be expected to protect the U.S. from the impacts of oil import interruptions.

Before entering consulting, Mr. Kahal held faculty positions with the Department of Economics at the University of Maryland and with Montgomery College teaching courses on economic principles, business and economic development.

<u>Publications and Consulting Reports</u>:

<u>Projected Electric Power Demands of the Baltimore Gas and Electric Company</u>, Maryland Power Plant Siting Program, 1979.

<u>Projected Electric Power Demands of the Allegheny Power System</u>, Maryland Power Plant Siting Program, January 1980.

<u>An Econometric Forecast of Electric Energy and Peak Demand on the Delmarva Peninsula</u>, Maryland Power Plant Siting Program, March 1980 (with Ralph E. Miller).

<u>A Benefit/Cost Methodology of the Marginal Cost Pricing of Tennessee Valley Authority Electricity</u>, prepared for the Board of Directors of the Tennessee Valley Authority, April 1980.

<u>An Evaluation of the Delmarva Power and Light Company Generating Capacity Profile and Expansion Plan</u>, (Interim Report), prepared for the Delaware Office of the Public Advocate, July 1980, (with Sharon L. Mason).

<u>Rhode Island-DOE Electric Utilities Demonstration Project, Third Interim Report on Preliminary Analysis of the Experimental Results</u>, prepared for the Economic Regulatory Administration, U.S. Department of Energy, July 1980.

<u>Petroleum Inventories and the Strategic Petroleum Reserve</u>, The Aerospace Corporation, prepared for the Strategic Petroleum Reserve Office, U.S. Department of Energy, December 1980.

<u>Alternatives to Central Station Coal and Nuclear Power Generation</u>, prepared for Argonne National Laboratory and the Office of Utility Systems, U.S. Department of Energy, August 1981.

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"An Assessment of the State-of-the-Art of Gas Utility Load Forecasting," (with Thomas Bacon, Jr. and Steven L. Estomin), published in the Proceedings of the Fourth NARUC Biennial Regulatory Information Conference, 1984.

"Nuclear Power and Investor Perceptions of Risk," (with Ralph E. Miller), published in The Energy Industries in Transition: 1985-2000 (John P. Weyant and Dorothy Sheffield, eds.), 1984.

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An Econometric Forecast of the Electric Power Loads of Baltimore Gas and Electric Company, two volumes (with others), prepared for the Maryland Power Plant Siting Program, 1985.

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A Review and Evaluation of the Load Forecasts of Houston Lighting & Power Company and Central Power & Light Company -- Past and Present, prepared for the Texas Public Utility Commission, December 1985, (with Marvin H. Kahn).

Power Plant Cumulative Environmental Impact Report for Maryland, principal author of three of the eight chapters in the report (Paul E. Miller, ed.), PPSP-CEIR-5, March 1986.

"Potential Emissions Reduction from Conservation, Load Management, and Alternative Power," published in Acid Deposition in Maryland: A Report to the Governor and General Assembly, Maryland Power Plant Research Program, AD-87-1, January 1987.

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Electric Power Rate Increases and the Cleveland Area Economy, prepared for the Northeast Ohio Areawide Coordinating Agency, October 1988.

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Expert Report on Capital Structure, Equity and Debt Costs, prepared for the Edmonton Regional Water Customers Group, August 30, 2006.

Maryland's Options to Reduce and Stabilize Electric Power Prices Following Restructuring, with Steven L. Estomin, prepared for the Power Plant Research Program, Maryland Department of Natural Resources, September 2006.

Expert Report of Matthew I. Kahal, on behalf of the U. S. Department of Justice, August 2008, Civil Action No. IP-99-1693C-MIS.

Conference and Workshop Presentations:

Workshop on State Load Forecasting Programs, sponsored by the Nuclear Regulatory Commission and Oak Ridge National Laboratory, February 1982 (presentation on forecasting methodology).

Fourteenth Annual Conference of the Michigan State University Institute for Public Utilities, December 1982 (presentation on problems in forecasting).

Conference on Conservation and Load Management, sponsored by the Massachusetts Energy Facilities Siting Council, May 1983 (presentation on cost-benefit criteria).

Maryland Conference on Load Forecasting, sponsored by the Maryland Power Plant Siting Program and the Maryland Public Service Commission, June 1983 (presentation on overforecasting power demands).

The 5th Annual Meetings of the International Association of Energy Economists, June 1983 (presentation on evaluating weatherization programs).

The NARUC Advanced Regulatory Studies Program (presented lectures on capacity planning for electric utilities), February 1984.

The 16th Annual Conference of the Institute of Public Utilities, Michigan State University (discussant on phase-in and excess capacity), December 1984.

U.S. Department of Energy Utilities Conference, Las Vegas, Nevada (presentation of current and future regulatory issues), May 1985.

The 18th Annual Conference of the Institute of Public Utilities, Michigan State University, Williamsburg, Virginia, December 1986 (discussant on cogeneration).

The NRECA Conference on Load Forecasting, sponsored by the National Rural Electric Cooperative Association, New Orleans, Louisiana, December 1987 (presentation on load forecast accuracy).

The Second Rutgers/New Jersey Department of Commerce Annual Conference on Energy Policy in the Middle Atlantic States, Rutgers University, April 1988 (presentation on spot pricing of electricity).

The NASUCA 1988 Mid-Year Meeting, Annapolis, Maryland, June 1988, sponsored by the National Association of State Utility Consumer Advocates (presentation on the FERC electricity avoided cost NOPRs).

The Thirty Second Atlantic Economic Society Conference, Washington, D.C., October 1991 (presentation of a paper on cost of capital issues for the Bell Operating Companies).

The NASUCA 1993 Mid-Year Meeting, St. Louis, Missouri, sponsored by the National Association of State Utility Consumer Advocates, June 1993 (presentation on regulatory issues concerning electric utility mergers).

The NASUCA and NARUC annual meetings in New York City, November 1993 (presentations and panel discussions on the emerging FERC policies on transmission pricing).

The NASUCA annual meetings in Reno, Nevada, November 1994 (presentation concerning the FERC NOPR on stranded cost recovery).

U.S. Department of Energy Utilities/Energy Management Workshop, March 1995 (presentation concerning electric utility competition).

The 1995 NASUCA Mid-Year Meeting, Breckenridge, Colorado, June 1995, (presentation concerning the FERC rulemaking on electric transmission open access).

The 1996 NASUCA Mid-Year Meeting, Chicago, Illinois, June 1996 (presentation concerning electric utility merger issues).

Conference on “Restructuring the Electric Industry,” sponsored by the National Consumers League and Electric Consumers Alliance, Washington, D.C., May 1997 (presentation on retail access pilot programs).

The 1997 Mid-Atlantic Conference of Regulatory Utilities Commissioners (MARUC), Hot Springs, Virginia, July 1997 (presentation concerning electric deregulation issues).

Power-Gen ‘97 International Conference, Dallas, Texas, December 1997 (presentation concerning utility embedded costs of generation supply).

Consumer Summit on Electric Competition, sponsored by the National Consumers League and Electric Consumers’ Alliance, Washington, D.C., March 2001 (presentation concerning generation supply and reliability).

National Association of State Utility Consumer Advocates, Mid-Year Meetings, Austin, Texas, June 16-17, 2002 (presenter and panelist on RTO/Standard Market Design issues).

Louisiana State Bar Association, Public Utility Section, October 2, 2002. (Presentation on Performance-Based Ratemaking and panelist on RTO issues). Baton Rouge, Louisiana.

Virginia State Corporation Commission/Virginia State Bar, Twenty Second National Regulatory Conference, May 10, 2004. (Presentation on Electric Transmission System Planning.) Williamsburg, Virginia.

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	Docket Number	Utility	Jurisdiction	Client	Subject
1.	27374 & 27375 October 1978	Long Island Lighting Company	New York Counties	Nassau & Suffolk	Economic Impacts of Proposed Rate Increase
2.	6807 January 1978	Generic	Maryland	MD Power Plant Siting Program	Load Forecasting
3.	78-676-EL-AIR February 1978	Ohio Power Company	Ohio	Ohio Consumers' Counsel	Test Year Sales and Revenues
4.	17667 May 1979	Alabama Power Company	Alabama	Attorney General	Test Year Sales, Revenues, Costs and Load Forecasts
5.	None April 1980	Tennessee Valley Authority	TVA Board	League of Women Voters	Time-of-Use Pricing
6.	R-80021082	West Penn Power Company	Pennsylvania	Office of Consumer Advocate	Load Forecasting, Marginal Cost pricing
7.	7259 (Phase I) October 1980	Potomac Edison Company	Maryland	MD Power Plant Siting Program	Load Forecasting
8.	7222 December 1980	Delmarva Power & Light Company	Maryland	MD Power Plant Siting Program	Need for Plant, Load Forecasting
9.	7441 June 1981	Potomac Electric Power Company	Maryland	Commission Staff	PURPA Standards
10.	7159 May 1980	Baltimore Gas & Electric	Maryland	Commission Staff	Time-of-Use Pricing
11.	81-044-E-42T	Monongahela Power	West Virginia	Commission Staff	Time-of-Use Rates
12.	7259 (Phase II) November 1981	Potomac Edison Company	Maryland	MD Power Plant Siting Program	Load Forecasting, Load Management
13.	1606 September 1981	Blackstone Valley Electric and Narragansett	Rhode Island	Division of Public Utilities	PURPA Standards
14.	RID 1819 April 1982	Pennsylvania Bell	Pennsylvania	Office of Consumer Advocate	Rate of Return
15.	82-0152 July 1982	Illinois Power Company	Illinois	U.S. Department of Defense	Rate of Return, CWIP

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	Docket Number	Utility	Jurisdiction	Client	Subject
16.	7559 September 1982	Potomac Edison Company	Maryland	Commission Staff	Cogeneration
17.	820150-EU September 1982	Gulf Power Company	Florida	Federal Executive Agencies	Rate of Return, CWIP
18.	82-057-15 January 1983	Mountain Fuel Supply Company	Utah	Federal Executive Agencies	Rate of Return, Capital Structure
19.	5200 August 1983	Texas Electric Service Company	Texas	Federal Executive Agencies	Cost of Equity
20.	28069 August 1983	Oklahoma Natural Gas	Oklahoma	Federal Executive Agencies	Rate of Return, deferred taxes, capital structure, attrition
21.	83-0537 February 1984	Commonwealth Edison Company	Illinois	U.S. Department of Energy	Rate of Return, capital structure, financial capability
22.	84-035-01 June 1984	Utah Power & Light Company	Utah	Federal Executive Agencies	Rate of Return
23.	U-1009-137 July 1984	Utah Power & Light Company	Idaho	U.S. Department of Energy	Rate of Return, financial condition
24.	R-842590 August 1984	Philadelphia Electric Company	Pennsylvania	Office of Consumer Advocate	Rate of Return
25.	840086-EI August 1984	Gulf Power Company	Florida	Federal Executive Agencies	Rate of Return, CWIP
26.	84-122-E August 1984	Carolina Power & Light Company	South Carolina	South Carolina Consumer Advocate	Rate of Return, CWIP, load forecasting
27.	CGC-83-G & CGC-84-G October 1984	Columbia Gas of Ohio	Ohio	Ohio Division of Energy	Load forecasting
28.	R-842621 October 1984	Western Pennsylvania Water Company	Pennsylvania	Office of Consumer Advocate	Test year sales
29.	R-842710 January 1985	ALLTEL Pennsylvania Inc.	Pennsylvania	Office of Consumer Advocate	Rate of Return
30.	ER-504 February 1985	Allegheny Generating Company	FERC	Office of Consumer Advocate	Rate of Return

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	Docket Number	Utility	Jurisdiction	Client	Subject
31.	R-842632 March 1985	West Penn Power Company	Pennsylvania	Office of Consumer Advocate	Rate of Return, conservation, time-of-use rates
32.	83-0537 & 84-0555 April 1985	Commonwealth Edison Company	Illinois	U.S. Department of Energy	Rate of Return, incentive rates, rate base
33.	Rulemaking Docket No. 11, May 1985	Generic	Delaware	Delaware Commission Staff	Interest rates on refunds
34.	29450 July 1985	Oklahoma Gas & Electric Company	Oklahoma	Oklahoma Attorney General	Rate of Return, CWIP in rate base
35.	1811 August 1985	Bristol County Water Company	Rhode Island	Division of Public Utilities	Rate of Return, capital Structure
36.	R-850044 & R-850045 August 1985	Quaker State & Continental Telephone Companies	Pennsylvania	Office of Consumer Advocate	Rate of Return
37.	R-850174 November 1985	Philadelphia Suburban Water Company	Pennsylvania	Office of Consumer Advocate	Rate of Return, financial conditions
38.	U-1006-265 March 1986	Idaho Power Company	Idaho	U.S. Department of Energy	Power supply costs and models
39.	EL-86-37 & EL-86-38 September 1986	Allegheny Generating Company	FERC	PA Office of Consumer Advocate	Rate of Return
40.	R-850287 June 1986	National Fuel Gas Distribution Corp.	Pennsylvania	Office of Consumer Advocate	Rate of Return
41.	1849 August 1986	Blackstone Valley Electric	Rhode Island	Division of Public Utilities	Rate of Return, financial condition
42.	86-297-GA-AIR November 1986	East Ohio Gas Company	Ohio	Ohio Consumers' Counsel	Rate of Return
43.	U-16945 December 1986	Louisiana Power & Light Company	Louisiana	Public Service Commission	Rate of Return, rate phase-in plan
44.	Case No. 7972 February 1987	Potomac Electric Power Company	Maryland	Commission Staff	Generation capacity planning, purchased power contract
45.	EL-86-58 & EL-86-59 March 1987	System Energy Resources and Middle South Services	FERC	Louisiana PSC	Rate of Return

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	Docket Number	Utility	Jurisdiction	Client	Subject
46.	ER-87-72-001 April 1987	Orange & Rockland	FERC	PA Office of Consumer Advocate	Rate of Return
47.	U-16945 April 1987	Louisiana Power & Light Company	Louisiana	Commission Staff	Revenue requirement update phase-in plan
48.	P-870196 May 1987	Pennsylvania Electric Company	Pennsylvania	Office of Consumer Advocate	Cogeneration contract
49.	86-2025-EL-AIR June 1987	Cleveland Electric Illuminating Company	Ohio	Ohio Consumers' Counsel	Rate of Return
50.	86-2026-EL-AIR June 1987	Toledo Edison Company	Ohio	Ohio Consumers' Counsel	Rate of Return
51.	87-4 June 1987	Delmarva Power & Light Company	Delaware	Commission Staff	Cogeneration/small power
52.	1872 July 1987	Newport Electric Company	Rhode Island	Commission Staff	Rate of Return
53.	WO 8606654 July 1987	Atlantic City Sewerage Company	New Jersey	Resorts International	Financial condition
54.	7510 August 1987	West Texas Utilities Company	Texas	Federal Executive Agencies	Rate of Return, phase-in
55.	8063 Phase I October 1987	Potomac Electric Power Company	Maryland	Power Plant Research Program	Economics of power plant site selection
56.	00439 November 1987	Oklahoma Gas & Electric Company	Oklahoma	Smith Cogeneration	Cogeneration economics
57.	RP-87-103 February 1988	Panhandle Eastern Pipe Line Company	FERC	Indiana Utility Consumer Counselor	Rate of Return
58.	EC-88-2-000 February 1988	Utah Power & Light Co. PacifiCorp	FERC	Nucor Steel	Merger economics
59.	87-0427 February 1988	Commonwealth Edison Company	Illinois	Federal Executive Agencies	Financial projections
60.	870840 February 1988	Philadelphia Suburban Water Company	Pennsylvania	Office of Consumer Advocate	Rate of Return

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	Docket Number	Utility	Jurisdiction	Client	Subject
61.	870832 March 1988	Columbia Gas of Pennsylvania	Pennsylvania	Office of Consumer Advocate	Rate of Return
62.	8063 Phase II July 1988	Potomac Electric Power Company	Maryland	Power Plant Research Program	Power supply study
63.	8102 July 1988	Southern Maryland Electric Cooperative	Maryland	Power Plant Research Program	Power supply study
64.	10105 August 1988	South Central Bell Telephone Co.	Kentucky	Attorney General	Rate of Return, incentive regulation
65.	00345 August 1988	Oklahoma Gas & Electric Company	Oklahoma	Smith Cogeneration	Need for power
66.	U-17906 September 1988	Louisiana Power & Light Company	Louisiana	Commission Staff	Rate of Return, nuclear power costs Industrial contracts
67.	88-170-EL-AIR October 1988	Cleveland Electric Illuminating Co.	Ohio	Northeast-Ohio Areawide Coordinating Agency	Economic impact study
68.	1914 December 1988	Providence Gas Company	Rhode Island	Commission Staff	Rate of Return
69.	U-12636 & U-17649 February 1989	Louisiana Power & Light Company	Louisiana	Commission Staff	Disposition of litigation proceeds
70.	00345 February 1989	Oklahoma Gas & Electric Company	Oklahoma	Smith Cogeneration	Load forecasting
71.	RP88-209 March 1989	Natural Gas Pipeline of America	FERC	Indiana Utility Consumer Counselor	Rate of Return
72.	8425 March 1989	Houston Lighting & Power Company	Texas	U.S. Department of Energy	Rate of Return
73.	EL89-30-000 April 1989	Central Illinois Public Service Company	FERC	Soyland Power Coop, Inc.	Rate of Return
74.	R-891208 May 1989	Pennsylvania American Water Company	Pennsylvania	Office of Consumer Advocate	Rate of Return

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	Docket Number	Utility	Jurisdiction	Client	Subject
75.	89-0033 May 1989	Illinois Bell Telephone Company	Illinois	Citizens Utility Board	Rate of Return
76.	881167-EI May 1989	Gulf Power Company	Florida	Federal Executive Agencies	Rate of Return
77.	R-891218 July 1989	National Fuel Gas Distribution Company	Pennsylvania	Office of Consumer Advocate	Sales forecasting
78.	8063, Phase III Sept. 1989	Potomac Electric Power Company	Maryland	Depart. Natural Resources	Emissions Controls
79.	37414-S2 October 1989	Public Service Company of Indiana	Indiana	Utility Consumer Counselor	Rate of Return, DSM, off-system sales, incentive regulation
80.	October 1989	Generic	U.S. House of Reps. Comm. on Ways & Means	NA	Excess deferred income tax
81.	38728 November 1989	Indiana Michigan Power Company	Indiana	Utility Consumer Counselor	Rate of Return
82.	RP89-49-000 December 1989	National Fuel Gas Supply Corporation	FERC	PA Office of Consumer Advocate	Rate of Return
83.	R-891364 December 1989	Philadelphia Electric Company	Pennsylvania	PA Office of Consumer Advocate	Financial impacts (surrebuttal only)
84.	RP89-160-000 January 1990	Trunkline Gas Company	FERC	Indiana Utility Consumer Counselor	Rate of Return
85.	EL90-16-000 November 1990	System Energy Resources, Inc.	FERC	Louisiana Public Service Commission	Rate of Return
86.	89-624 March 1990	Bell Atlantic	FCC	PA Office of Consumer Advocate	Rate of Return
87.	8245 March 1990	Potomac Edison Company	Maryland	Depart. Natural Resources	Avoided Cost
88.	000586 March 1990	Public Service Company of Oklahoma	Oklahoma	Smith Cogeneration Mgmt.	Need for Power

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	Docket Number	Utility	Jurisdiction	Client	Subject
89.	38868 March 1990	Indianapolis Water Company	Indiana	Utility Consumer Counselor	Rate of Return
90.	1946 March 1990	Blackstone Valley Electric Company	Rhode Island	Division of Public Utilities	Rate of Return
91.	000776 April 1990	Oklahoma Gas & Electric Company	Oklahoma	Smith Cogeneration Mgmt.	Need for Power
92.	890366 May 1990, December 1990	Metropolitan Edison Company	Pennsylvania	Office of Consumer Advocate	Competitive Bidding Program Avoided Costs
93.	EC-90-10-000 May 1990	Northeast Utilities	FERC	Maine PUC, et. al.	Merger, Market Power, Transmission Access
94.	ER-891109125 July 1990	Jersey Central Power & Light	New Jersey	Rate Counsel	Rate of Return
95.	R-901670 July 1990	National Fuel Gas Distribution Corp.	Pennsylvania	Office of Consumer Advocate	Rate of Return Test year sales
96.	8201 October 1990	Delmarva Power & Light Company	Maryland	Depart. Natural Resources	Competitive Bidding, Resource Planning
97.	EL90-45-000 April 1991	Entergy Services, Inc.	FERC	Louisiana PSC	Rate of Return
98.	GR90080786J January 1991	New Jersey Natural Gas	New Jersey	Rate Counsel	Rate of Return
99.	90-256 January 1991	South Central Bell Telephone Company	Kentucky	Attorney General	Rate of Return
100.	U-17949A February 1991	South Central Bell Telephone Company	Louisiana	Louisiana PSC	Rate of Return
101.	ER90091090J April 1991	Atlantic City Electric Company	New Jersey	Rate Counsel	Rate of Return
102.	8241, Phase I April 1991	Baltimore Gas & Electric Company	Maryland	Dept. of Natural Resources	Environmental controls

	Docket Number	Utility	Jurisdiction	Client	Subject
103.	8241, Phase II May 1991	Baltimore Gas & Electric Company	Maryland	Dept. of Natural Resources	Need for Power, Resource Planning
104.	39128 May 1991	Indianapolis Water Company	Indiana	Utility Consumer Counselor	Rate of Return, rate base, financial planning
105.	P-900485 May 1991	Duquesne Light Company	Pennsylvania	Office of Consumer Advocate	Purchased power contract and related ratemaking
106.	G900240 P910502 May 1991	Metropolitan Edison Company Pennsylvania Electric Company	Pennsylvania	Office of Consumer Advocate	Purchased power contract and related ratemaking
107.	GR901213915 May 1991	Elizabethtown Gas Company	New Jersey	Rate Counsel	Rate of Return
108.	91-5032 August 1991	Nevada Power Company	Nevada	U.S. Dept. of Energy	Rate of Return
109.	EL90-48-000 November 1991	Entergy Services	FERC	Louisiana PSC	Capacity transfer
110.	000662 September 1991	Southwestern Bell Telephone	Oklahoma	Attorney General	Rate of Return
111.	U-19236 October 1991	Arkansas Louisiana Gas Company	Louisiana	Louisiana PSC Staff	Rate of Return
112.	U-19237 December 1991	Louisiana Gas Service Company	Louisiana	Louisiana PSC Staff	Rate of Return
113.	ER91030356J October 1991	Rockland Electric Company	New Jersey	Rate Counsel	Rate of Return
114.	GR91071243J February 1992	South Jersey Gas Company	New Jersey	Rate Counsel	Rate of Return
115.	GR91081393J March 1992	New Jersey Natural Gas Company	New Jersey	Rate Counsel	Rate of Return
116.	P-870235 et al. March 1992	Pennsylvania Electric Company	Pennsylvania	Office of Consumer Advocate	Cogeneration contracts

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	Docket Number	Utility	Jurisdiction	Client	Subject
117.	8413 March 1992	Potomac Electric Power Company	Maryland	Dept. of Natural Resources	IPP purchased power contracts
118.	39236 March 1992	Indianapolis Power & Light Company	Indiana	Utility Consumer Counselor	Least-cost planning Need for power
119.	R-912164 April 1992	Equitable Gas Company	Pennsylvania	Office of Consumer Advocate	Rate of Return
120.	ER-91111698J May 1992	Public Service Electric & Gas Company	New Jersey	Rate Counsel	Rate of Return
121.	U-19631 June 1992	Trans Louisiana Gas Company	Louisiana	PSC Staff	Rate of Return
122.	ER-91121820J July 1992	Jersey Central Power & Light Company	New Jersey	Rate Counsel	Rate of Return
123.	R-00922314 August 1992	Metropolitan Edison Company	Pennsylvania	Office of Consumer Advocate	Rate of Return
124.	92-049-05 September 1992	US West Communications	Utah	Committee of Consumer Services	Rate of Return
125.	92PUE0037 September 1992	Commonwealth Gas Company	Virginia	Attorney General	Rate of Return
126.	EC92-21-000 September 1992	Entergy Services, Inc.	FERC	Louisiana PSC	Merger Impacts (Affidavit)
127.	ER92-341-000 December 1992	System Energy Resources	FERC	Louisiana PSC	Rate of Return
128.	U-19904 November 1992	Louisiana Power & Light Company	Louisiana	Staff	Merger analysis, competition competition issues
129.	8473 November 1992	Baltimore Gas & Electric Company	Maryland	Dept. of Natural Resources	QF contract evaluation
130.	IPC-E-92-25 January 1993	Idaho Power Company	Idaho	Federal Executive Agencies	Power Supply Clause

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	Docket Number	Utility	Jurisdiction	Client	Subject
131.	E002/GR-92-1185 February 1993	Northern States Power Company	Minnesota	Attorney General	Rate of Return
132.	92-102, Phase II March 1992	Central Maine Power Company	Maine	Staff	QF contracts prudence and procurements practices
133.	EC92-21-000 March 1993	Entergy Corporation	FERC	Louisiana PSC	Merger Issues
134.	8489 March 1993	Delmarva Power & Light Company	Maryland	Dept. of Natural Resources	Power Plant Certification
135.	11735 April 1993	Texas Electric Utilities Company	Texas	Federal Executives Agencies	Rate of Return
136.	2082 May 1993	Providence Gas Company	Rhode Island	Division of Public Utilities	Rate of Return
137.	P-00930715 December 1993	Bell Telephone Company of Pennsylvania	Pennsylvania	Office of Consumer Advocate	Rate of Return, Financial Projections, Bell/TCI merger
138.	R-00932670 February 1994	Pennsylvania-American Water Company	Pennsylvania	Office of Consumer Advocate	Rate of Return
139.	8583 February 1994	Conowingo Power Company	Maryland	Dept. of Natural Resources	Competitive Bidding for Power Supplies
140.	E-015/GR-94-001 April 1994	Minnesota Power & Light Company	Minnesota	Attorney General	Rate of Return
141.	CC Docket No. 94-1 May 1994	Generic Telephone	FCC	MCI Comm. Corp.	Rate of Return
142.	92-345, Phase II June 1994	Central Maine Power Company	Maine	Advocacy Staff	Price Cap Regulation Fuel Costs
143.	93-11065 April 1994	Nevada Power Company	Nevada	Federal Executive Agencies	Rate of Return
144.	94-0065 May 1994	Commonwealth Edison Company	Illinois	Federal Executive Agencies	Rate of Return
145.	GR94010002J June 1994	South Jersey Gas Company	New Jersey	Rate Counsel	Rate of Return

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	Docket Number	Utility	Jurisdiction	Client	Subject
146.	WR94030059 July 1994	New Jersey-American Water Company	New Jersey	Rate Counsel	Rate of Return
147.	RP91-203-000 June 1994	Tennessee Gas Pipeline Company	FERC	Customer Group	Environmental Externalities (oral testimony only)
148.	ER94-998-000 July 1994	Ocean State Power	FERC	Boston Edison Company	Rate of Return
149.	R-00942986 July 1994	West Penn Power Company	Pennsylvania	Office of Consumer Advocate	Rate of Return, Emission Allowances
150.	94-121 August 1994	South Central Bell Telephone Company	Kentucky	Attorney General	Rate of Return
151.	35854-S2 November 1994	PSI Energy, Inc.	Indiana	Utility Consumer Counsel	Merger Savings and Allocations
152.	IPC-E-94-5 November 1994	Idaho Power Company	Idaho	Federal Executive Agencies	Rate of Return
153.	November 1994	Edmonton Water	Alberta, Canada	Regional Customer Group	Rate of Return (Rebuttal Only)
154.	90-256 December 1994	South Central Bell Telephone Company	Kentucky	Attorney General	Incentive Plan True-Ups
155.	U-20925 February 1995	Louisiana Power & Light Company	Louisiana	PSC Staff	Rate of Return Industrial Contracts Trust Fund Earnings
156.	R-00943231 February 1995	Pennsylvania-American Water Company	Pennsylvania	Consumer Advocate	Rate of Return
157.	8678 March 1995	Generic	Maryland	Dept. Natural Resources	Electric Competition Incentive Regulation (oral only)
158.	R-000943271 April 1995	Pennsylvania Power & Light Company	Pennsylvania	Consumer Advocate	Rate of Return Nuclear decommissioning Capacity Issues
159.	U-20925 May 1995	Louisiana Power & Light Company	Louisiana	Commission Staff	Class Cost of Service Issues

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160.	2290 June 1995	Narragansett Electric Company	Rhode Island	Division Staff	Rate of Return
161.	U-17949E June 1995	South Central Bell Telephone Company	Louisiana	Commission Staff	Rate of Return
162.	2304 July 1995	Providence Water Supply Board	Rhode Island	Division Staff	Cost recovery of Capital Spending Program
163.	ER95-625-000 et al. August 1995	PSI Energy, Inc.	FERC	Office of Utility Consumer Counselor	Rate of Return
164.	P-00950915 et al. September 1995	Paxton Creek Cogeneration Assoc.	Pennsylvania	Office of Consumer Advocate	Cogeneration Contract Amendment
165.	8702 September 1995	Potomac Edison Company	Maryland	Dept. of Natural Resources	Allocation of DSM Costs (oral only)
166.	ER95-533-001 September 1995	Ocean State Power	FERC	Boston Edison Co.	Cost of Equity
167.	40003 November 1995	PSI Energy, Inc.	Indiana	Utility Consumer Counselor	Rate of Return Retail wheeling
168.	P-55, SUB 1013 January 1996	BellSouth	North Carolina	AT&T	Rate of Return
169.	P-7, SUB 825 January 1996	Carolina Tel.	North Carolina	AT&T	Rate of Return
170.	February 1996	Generic Telephone	FCC	MCI	Cost of capital
171.	95A-531EG April 1996	Public Service Company of Colorado	Colorado	Federal Executive Agencies	Merger issues
172.	ER96-399-000 May 1996	Northern Indiana Public Service Company	FERC	Indiana Office of Utility Consumer Counselor	Cost of capital
173.	8716 June 1996	Delmarva Power & Light Company	Maryland	Dept. of Natural Resources	DSM programs
174.	8725 July 1996	BGE/PEPCO	Maryland	Md. Energy Admin.	Merger Issues

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	Docket Number	Utility	Jurisdiction	Client	Subject
175.	U-20925 August 1996	Entergy Louisiana, Inc.	Louisiana	PSC Staff	Rate of Return Allocations Fuel Clause
176.	EC96-10-000 September 1996	BGE/PEPCO	FERC	Md. Energy Admin.	Merger issues competition
177.	EL95-53-000 November 1996	Entergy Services, Inc.	FERC	Louisiana PSC	Nuclear Decommissioning
178.	WR96100768 March 1997	Consumers NJ Water Company	New Jersey	Ratepayer Advocate	Cost of Capital
179.	WR96110818 April 1997	Middlesex Water Co.	New Jersey	Ratepayer Advocate	Cost of Capital
180.	U-11366 April 1997	Ameritech Michigan	Michigan	MCI	Access charge reform/financial condition
181.	97-074 May 1997	BellSouth	Kentucky	MCI	Rate Rebalancing financial condition
182.	2540 June 1997	New England Power	Rhode Island	PUC Staff	Divestiture Plan
183.	96-336-TP-CSS June 1997	Ameritech Ohio	Ohio	MCI	Access Charge reform Economic impacts
184.	WR97010052 July 1997	Maxim Sewerage Corp.	New Jersey	Ratepayer Advocate	Rate of Return
185.	97-300 August 1997	LG&E/KU	Kentucky	Attorney General	Merger Plan
186.	Case No. 8738 August 1997	Generic (oral testimony only)	Maryland	Dept. of Natural Resources	Electric Restructuring Policy
187.	Docket No. 2592 September 1997	Eastern Utilities	Rhode Island	PUC Staff	Generation Divestiture
188.	Case No.97-247 September 1997	Cincinnati Bell Telephone	Kentucky	MCI	Financial Condition

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	Docket Number	Utility	Jurisdiction	Client	Subject
189.	Docket No. U-20925 November 1997	Entergy Louisiana	Louisiana	PSC Staff	Rate of Return
190.	Docket No. D97.7.90 November 1997	Montana Power Co.	Montana	Montana Consumers Counsel	Stranded Cost
191.	Docket No. EO97070459 November 1997	Jersey Central Power & Light Co.	New Jersey	Ratepayer Advocate	Stranded Cost
192.	Docket No. R-00974104 November 1997	Duquesne Light Co.	Pennsylvania	Office of Consumer Advocate	Stranded Cost
193.	Docket No. R-00973981 November 1997	West Penn Power Co.	Pennsylvania	Office of Consumer Advocate	Stranded Cost
194.	Docket No. A-1101150F0015 November 1997	Allegheny Power System DQE, Inc.	Pennsylvania	Office of Consumer Advocate	Merger Issues
195.	Docket No. WR97080615 January 1998	Consumers NJ Water Company	New Jersey	Ratepayer Advocate	Rate of Return
196.	Docket No. R-00974149 January 1998	Pennsylvania Power Company	Pennsylvania	Office of Consumer Advocate	Stranded Cost
197.	Case No. 8774 January 1998	Allegheny Power System DQE, Inc.	Maryland	Dept. of Natural Resources MD Energy Administration	Merger Issues
198.	Docket No. U-20925 (SC) March 1998	Entergy Louisiana, Inc.	Louisiana	Commission Staff	Restructuring, Stranded Costs, Market Prices
199.	Docket No. U-22092 (SC) March 1998	Entergy Gulf States, Inc.	Louisiana	Commission Staff	Restructuring, Stranded Costs, Market Prices
200.	Docket Nos. U-22092 (SC) and U-20925(SC) May 1998	Entergy Gulf States and Entergy Louisiana	Louisiana	Commission Staff	Standby Rates
201.	Docket No. WR98010015 May 1998	NJ American Water Co.	New Jersey	Ratepayer Advocate	Rate of Return
202.	Case No. 8794 December 1998	Baltimore Gas & Electric Co.	Maryland	MD Energy Admin./Dept. Of Natural Resources	Stranded Cost/ Transition Plan

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	Docket Number	Utility	Jurisdiction	Client	Subject
203.	Case No. 8795 December 1998	Delmarva Power & Light Co.	Maryland	MD Energy Admin./Dept. Of Natural Resources	Stranded Cost/ Transition Plan
204.	Case No. 8797 January 1998	Potomac Edison Co.	Maryland	MD Energy Admin./Dept. Of Natural Resources	Stranded Cost/ Transition Plan
205.	Docket No. WR98090795 March 1999	Middlesex Water Co.	New Jersey	Ratepayer Advocate	Rate of Return
206.	Docket No. 99-02-05 April 1999	Connecticut Light & Power	Connecticut	Attorney General	Stranded Costs
207.	Docket No. 99-03-04 May 1999	United Illuminating Company	Connecticut	Attorney General	Stranded Costs
208.	Docket No. U-20925 (FRP) June 1999	Entergy Louisiana, Inc.	Louisiana	Staff	Capital Structure
209.	Docket No. EC-98-40-000, et al. May 1999	American Electric Power/ Central & Southwest	FERC	Arkansas PSC	Market Power Mitigation
210.	Docket No. 99-03-35 July 1999	United Illuminating Company	Connecticut	Attorney General	Restructuring
211.	Docket No. 99-03-36 July 1999	Connecticut Light & Power Co.	Connecticut	Attorney General	Restructuring
212.	WR99040249 Oct. 1999	Environmental Disposal Corp.	New Jersey	Ratepayer Advocate	Rate of Return
213.	2930 Nov. 1999	NEES/EUA	Rhode Island	Division Staff	Merger/Cost of Capital
214.	DE99-099 Nov. 1999	Public Service New Hampshire	New Hampshire	Consumer Advocate	Cost of Capital Issues
215.	00-01-11 Feb. 2000	Con Ed/NU	Connecticut	Attorney General	Merger Issues
216.	Case No. 8821 May 2000	Reliant/ODEC	Maryland	Dept. of Natural Resources	Need for Power/Plant Operations

	Docket Number	Utility	Jurisdiction	Client	Subject
217.	Case No. 8738 July 2000	Generic	Maryland	Dept. of Natural Resources	DSM Funding
218.	Case No. U-23356 June 2000	Entergy Louisiana, Inc.	Louisiana	PSC Staff	Fuel Prudence Issues Purchased Power
219.	Case No. 21453, et al July 2000	SWEPCO	Louisiana	PSC Staff	Stranded Costs
220.	Case No. 20925 (B) July 2000	Entergy Louisiana	Louisiana	PSC Staff	Purchase Power Contracts
221.	Case No. 24889 August 2000	Entergy Louisiana	Louisiana	PSC Staff	Purchase Power Contracts
222.	Case No. 21453, et al. February 2001	CLECO	Louisiana	PSC Staff	Stranded Costs
223.	P-00001860 and P-0000181 March 2001	GPU Companies	Pennsylvania	Office of Consumer Advocate	Rate of Return
224.	CVOL-0505662-S March 2001	ConEd/NU	Connecticut Superior Court	Attorney General	Merger (Affidavit)
225.	U-20925 (SC) March 2001	Entergy Louisiana	Louisiana	PSC Staff	Stranded Costs
226.	U-22092 (SC) March 2001	Entergy Gulf States	Louisiana	PSC Staff	Stranded Costs
227.	U-25533 May 2001	Entergy Louisiana/ Gulf States	Louisiana Interruptible Service	PSC Staff	Purchase Power
228.	P-00011872 May 2001	Pike County Pike	Pennsylvania	Office of Consumer Advocate	Rate of Return
229.	8893 July 2001	Baltimore Gas & Electric Co.	Maryland	MD Energy Administration	Corporate Restructuring
230.	8890 September 2001	Potomac Electric/Connectivity	Maryland	MD Energy Administration	Merger Issues

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	Docket Number	Utility	Jurisdiction	Client	Subject
231.	U-25533 August 2001	Entergy Louisiana / Gulf States	Louisiana	Staff	Purchase Power Contracts
232.	U-25965 November 2001	Generic	Louisiana	Staff	RTO Issues
233.	3401 March 2002	New England Gas Co.	Rhode Island	Division of Public Utilities	Rate of Return
234.	99-833-MJR April 2002	Illinois Power Co.	U.S. District Court	U.S. Department of Justice	New Source Review
235.	U-25533 March 2002	Entergy Louisiana/ Gulf States	Louisiana	PSC Staff	Nuclear Uprates Purchase Power
236.	P-00011872 May 2002	Pike County Power & Light	Pennsylvania	Consumer Advocate	POLR Service Costs
237.	U-26361, Phase I May 2002	Entergy Louisiana/ Gulf States	Louisiana	PSC Staff	Purchase Power Cost Allocations
238.	R-00016849C001 et al. June 2002	Generic	Pennsylvania	Pennsylvania OCA	Rate of Return
239.	U-26361, Phase II July 2002	Entergy Louisiana/ Entergy Gulf States	Louisiana	PSC Staff	Purchase Power Contracts
240.	U-20925(B) August 2002	Entergy Louisiana	Louisiana	PSC Staff	Tax Issues
241.	U-26531 October 2002	SWEPCO	Louisiana	PSC Staff	Purchase Power Contract
242.	8936 October 2002	Delmarva Power & Light	Maryland	Energy Administration Dept. Natural Resources	Standard Offer Service
243.	U-25965 November 2002	SWEPCO/AEP	Louisiana	PSC Staff	RTO Cost/Benefit
244.	8908 Phase I November 2002	Generic	Maryland	Energy Administration Dept. Natural Resources	Standard Offer Service
245.	02S-315EG November 2002	Public Service Company of Colorado	Colorado	Fed. Executive Agencies	Rate of Return

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	Docket Number	Utility	Jurisdiction	Client	Subject
246.	EL02-111-000 December 2002	PJM/MISO	FERC	MD PSC	Transmission Ratemaking
247.	02-0479 February 2003	Commonwealth Edison	Illinois	Dept. of Energy	POLR Service
248.	PL03-1-000 March 2003	Generic	FERC	NASUCA	Transmission Pricing (Affidavit)
249.	U-27136 April 2003	Entergy Louisiana	Louisiana	Staff	Purchase Power Contracts
250.	8908 Phase II July 2003	Generic	Maryland	Energy Administration Dept. of Natural Resources	Standard Offer Service
251.	U-27192 June 2003	Entergy Louisiana and Gulf States	Louisiana	LPSC Staff	Purchase Power Contract Cost Recovery
252.	C2-99-1181 October 2003	Ohio Edison Company	U.S. District Court	U.S. Department of Justice, et al.	Clean Air Act Compliance Economic Impact (Report)
253.	RP03-398-000 December 2003	Northern Natural Gas Co.	FERC	Municipal Distributors Group/Gas Task Force	Rate of Return
254.	8738 December 2003	Generic	Maryland	Energy Admin Department of Natural Resources	Environmental Disclosure (oral only)
255.	U-27136 December 2003	Entergy Louisiana, Inc.	Louisiana	PSC Staff	Purchase Power Contracts
256.	U-27192, Phase II October/December 2003	Entergy Louisiana & Entergy Gulf States	Louisiana	PSC Staff	Purchase Power Contracts
257.	WC Docket 03-173 December 2003	Generic	FCC	MCI	Cost of Capital (TELRIC)
258.	ER 030 20110 January 2004	Atlantic City Electric	New Jersey	Ratepayer Advocate	Rate of Return
259.	E-01345A-03-0437 January 2004	Arizona Public Service Company	Arizona	Federal Executive Agencies	Rate of Return
260.	03-10001 January 2004	Nevada Power Company	Nevada	U.S. Dept. of Energy	Rate of Return

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	Docket Number	Utility	Jurisdiction	Client	Subject
261.	R-00049255 June 2004	PPL Elec. Utility	Pennsylvania	Office of Consumer Advocate	Rate of Return
262.	U-20925 July 2004	Entergy Louisiana, Inc.	Louisiana	PSC Staff	Rate of Return Capacity Resources
263.	U-27866 September 2004	Southwest Electric Power Co.	Louisiana	PSC Staff	Purchase Power Contract
264.	U-27980 September 2004	Cleco Power	Louisiana	PSC Staff	Purchase Power Contract
265.	U-27865 October 2004	Entergy Louisiana, Inc. Entergy Gulf States	Louisiana	PSC Staff	Purchase Power Contract
266.	RP04-155 December 2004	Northern Natural Gas Company	FERC	Municipal Distributors Group/Gas Task Force	Rate of Return
267.	U-27836 January 2005	Entergy Louisiana/ Gulf States	Louisiana	PSC Staff	Power plant Purchase and Cost Recovery
268.	U-199040 et al. February 2005	Entergy Gulf States/ Louisiana	Louisiana	PSC Staff	Global Settlement, Multiple rate proceedings
269.	EF03070532 March 2005	Public Service Electric & Gas	New Jersey	Ratepayers Advocate	Securitization of Deferred Costs
270.	05-0159 June 2005	Commonwealth Edison	Illinois	Department of Energy	POLR Service
271.	U-28804 June 2005	Entergy Louisiana	Louisiana	LPSC Staff	QF Contract
272.	U-28805 June 2005	Entergy Gulf States	Louisiana	LPSC Staff	QF Contract
273.	05-0045-EI June 2005	Florida Power & Lt.	Florida	Federal Executive Agencies	Rate of Return
274.	9037 July 2005	Generic	Maryland	MD. Energy Administration	POLR Service
275.	U-28155 August 2005	Entergy Louisiana Entergy Gulf States	Louisiana	LPSC Staff	Independent Coordinator of Transmission Plan

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	Docket Number	Utility	Jurisdiction	Client	Subject
276.	U-27866-A September 2005	Southwestern Electric Power Company	Louisiana	LPSC Staff	Purchase Power Contract
277.	U-28765 October 2005	Cleco Power LLC	Louisiana	LPSC Staff	Purchase Power Contract
278.	U-27469 October 2005	Entergy Louisiana Entergy Gulf States	Louisiana	LPSC Staff	Avoided Cost Methodology
279.	A-313200F007 October 2005	Sprint (United of PA)	Pennsylvania	Office of Consumer Advocate	Corporate Restructuring
280.	EM05020106 November 2005	Public Service Electric & Gas Company	New Jersey	Ratepayer Advocate	Merger Issues
281.	U-28765 December 2005	Cleco Power LLC	Louisiana	LPSC Staff	Plant Certification, Financing, Rate Plan
282.	U-29157 February 2006	Cleco Power LLC	Louisiana	LPSC Staff	Storm Damage Financing
283.	U-29204 March 2006	Entergy Louisiana Entergy Gulf States	Louisiana	LPSC Staff	Purchase power contracts
284.	A-310325F006 March 2006	Alltel	Pennsylvania	Office of Consumer Advocate	Merger, Corporate Restructuring
285.	9056 March 2006	Generic	Maryland	Maryland Energy Administration	Standard Offer Service Structure
286.	C2-99-1182 April 2006	American Electric Power Utilities	U. S. District Court Southern District, Ohio	U. S. Department of Justice	New Source Review Enforcement (expert report)
287.	EM05121058 April 2006	Atlantic City Electric	New Jersey	Ratepayer Advocate	Power plant Sale
288.	ER05121018 June 2006	Jersey Central Power & Light Company	New Jersey	Ratepayer Advocate	NUG Contracts Cost Recovery
289.	U-21496, Subdocket C June 2006	Cleco Power LLC	Louisiana	Commission Staff	Rate Stabilization Plan
290.	GR0510085 June 2006	Public Service Electric & Gas Company	New Jersey	Ratepayer Advocate	Rate of Return (gas services)

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	Docket Number	Utility	Jurisdiction	Client	Subject
291.	R-000061366 July 2006	Metropolitan Ed. Company Penn. Electric Company	Pennsylvania	Office of Consumer Advocate	Rate of Return
292.	9064 September 2006	Generic	Maryland	Energy Administration	Standard Offer Service
293.	U-29599 September 2006	Cleco Power LLC	Louisiana	Commission Staff	Purchase Power Contracts
294.	WR06030257 September 2006	New Jersey American Water Company	New Jersey	Rate Counsel	Rate of Return
295.	U-27866/U-29702 October 2006	Southwestern Electric Power Company	Louisiana	Commission Staff	Purchase Power/Power Plant Certification
296.	9063 October 2006	Generic	Maryland	Energy Administration Department of Natural Resources	Generation Supply Policies
297.	EM06090638 November 2006	Atlantic City Electric	New Jersey	Rate Counsel	Power Plant Sale
298.	C-2000065942 November 2006	Pike County Light & Power	Pennsylvania	Consumer Advocate	Generation Supply Service
299.	ER06060483 November 2006	Rockland Electric Company	New Jersey	Rate Counsel	Rate of Return
300.	A-110150F0035 December 2006	Duquesne Light Company	Pennsylvania	Consumer Advocate	Merger Issues
301.	U-29203, Phase II January 2007	Entergy Gulf States Entergy Louisiana	Louisiana	Commission Staff	Storm Damage Cost Allocation
302.	06-11022 February 2007	Nevada Power Company	Nevada	U.S. Dept. of Energy	Rate of Return
303.	U-29526 March 2007	Cleco Power	Louisiana	Commission Staff	Affiliate Transactions
304.	P-00072245 March 2007	Pike County Light & Power	Pennsylvania	Consumer Advocate	Provider of Last Resort Service
305.	P-00072247 March 2007	Duquesne Light Company	Pennsylvania	Consumer Advocate	Provider of Last Resort Service

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	Docket Number	Utility	Jurisdiction	Client	Subject
306.	EM07010026 May 2007	Jersey Central Power & Light Company	New Jersey	Rate Counsel	Power Plant Sale
307.	U-30050 June 2007	Entergy Louisiana Entergy Gulf States	Louisiana	Commission Staff	Purchase Power Contract
308.	U-29956 June 2007	Entergy Louisiana	Louisiana	Commission Staff	Black Start Unit
309.	U-29702 June 2007	Southwestern Electric Power Company	Louisiana	Commission Staff	Power Plant Certification
310.	U-29955 July 2007	Entergy Louisiana Entergy Gulf States	Louisiana	Commission Staff	Purchase Power Contracts
311.	2007-67 July 2007	FairPoint Communications	Maine	Office of Public Advocate	Merger Financial Issues
312.	P-00072259 July 2007	Metropolitan Edison Co.	Pennsylvania	Office of Consumer Advocate	Purchase Power Contract Restructuring
313.	EO07040278 September 2007	Public Service Electric & Gas	New Jersey	Rate Counsel	Solar Energy Program Financial Issues
314.	U-30192 September 2007	Entergy Louisiana	Louisiana	Commission Staff	Power Plant Certification Ratemaking, Financing
315.	9117 (Phase II) October 2007	Generic (Electric)	Maryland	Energy Administration	Standard Offer Service Reliability
316.	U-30050 November 2007	Entergy Gulf States	Louisiana	Commission Staff	Power Plant Acquisition
317.	IPC-E-07-8 December 2007	Idaho Power Co.	Idaho	U.S. Department of Energy	Cost of Capital
318.	U-30422 (Phase I) January 2008	Entergy Gulf States	Louisiana	Commission Staff	Purchase Power Contract
319.	U-29702 (Phase II) February, 2008	Southwestern Electric Power Co.	Louisiana	Commission Staff	Power Plant Certification
320.	March 2008	Delmarva Power & Light	Delaware State Senate	Senate Committee	Wind Energy Economics

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	Docket Number	Utility	Jurisdiction	Client	Subject
321.	U-30192 (Phase II) March 2008	Entergy Louisiana	Louisiana	Commission Staff	Cash CWIP Policy, Credit Ratings
322.	U-30422 (Phase II) April 2008	Entergy Gulf States - LA	Louisiana	Commission Staff	Power Plant Acquisition
323.	U-29955 (Phase II) April 2008	Entergy Gulf States - LA Entergy Louisiana	Louisiana	Commission Staff	Purchase Power Contract
324.	GR-070110889 April 2008	New Jersey Natural Gas Company	New Jersey	Rate Counsel	Cost of Capital
325.	WR-08010020 July 2008	New Jersey American Water Company	New Jersey	Rate Counsel	Cost of Capital
326.	U-28804-A August 2008	Entergy Louisiana	Louisiana	Commission Staff	Cogeneration Contract
327.	IP-99-1693C-M/S August 2008	Duke Energy Indiana	Federal District Court	U.S. Department of Justice/ Environmental Protection Agency	Clean Air Act Compliance (Expert Report)
328.	U-30670 September 2008	Entergy Louisiana	Louisiana	Commission Staff	Nuclear Plant Equipment Replacement
329.	9149 October 2008	Generic	Maryland	Department of Natural Resources	Capacity Adequacy/Reliability
330.	IPC-E-08-10 October 2008	Idaho Power Company	Idaho	U.S. Department of Energy	Cost of Capital
331.	U-30727 October 2008	Cleco Power LLC	Louisiana	Commission Staff	Purchased Power Contract
332.	U-30689-A December 2008	Cleco Power LLC	Louisiana	Commission Staff	Transmission Upgrade Project
333.	IP-99-1693C-M/S February 2009	Duke Energy Indiana	Federal District Court	U.S. Department of Justice/EPA	Clean Air Act Compliance (Oral Testimony)
334.	U-30192, Phase II February 2009	Entergy Louisiana, LLC	Louisiana	Commission Staff	CWIP Rate Request Plant Allocation
335.	U-28805-B February 2009	Entergy Gulf States, LLC	Louisiana	Commission Staff	Cogeneration Contract

	Docket Number	Utility	Jurisdiction	Client	Subject
336.	P-2009-2093055, et al. May 2009	Metropolitan Edison Pennsylvania Electric	Pennsylvania	Office of Consumer Advocate	Default Service
337.	U-30958 July 2009	Cleco Power	Louisiana	Commission Staff	Purchase Power Contract
338.	EO08050326 August 2009	Jersey Central Power Light Co.	New Jersey	Rate Counsel	Demand Response Cost Recovery
339.	GR09030195 August 2009	Elizabethtown Gas	New Jersey	New Jersey Rate Counsel	Cost of Capital
340.	U-30422-A August 2009	Entergy Gulf States	Louisiana	Staff	Generating Unit Purchase
341.	CV 1:99-01693 August 2009	Duke Energy Indiana	Federal District Court – Indiana	U. S. DOJ/EPA, *et al.*	Environmental Compliance Rate Impacts (Expert Report)
342.	4065 September 2009	Narragansett Electric	Rhode Island	Division Staff	Cost of Capital
343.	U-30689 September 2009	Cleco Power	Louisiana	Staff	Cost of Capital, Rate Design, Other Rate Case Issues
344.	U-31147 October 2009	Entergy Gulf States Entergy Louisiana	Louisiana	Staff	Purchase Power Contracts
345.	U-30913 November 2009	Cleco Power	Louisiana	Staff	Certification of Generating Unit
346.	M-2009-2123951 November 2009	West Penn Power	Pennsylvania	Office of Consumer Advocate	Smart Meter Cost of Capital (Surrebuttal Only)
347.	GR09050422 November 2009	Public Service Electric & Gas Company	New Jersey	Rate Counsel	Cost of Capital
348.	D-09-49 November 2009	Narragansett Electric	Rhode Island	Division Staff	Securities Issuances
349.	U-29702, Phase II November 2009	Southwestern Electric Power Company	Louisiana	Commission Staff	Cash CWIP Recovery
350.	U-30981 December 2009	Entergy Louisiana Entergy Gulf States	Louisiana	Commission Staff	Storm Damage Cost Allocation

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	Docket Number	Utility	Jurisdiction	Client	Subject
351.	U-31196 (ITA Phase) February 2010	Entergy Louisiana	Louisiana	Staff	Purchase Power Contract
352.	ER09080668 March 2010	Rockland Electric	New Jersey	Rate Counsel	Rate of Return
353.	GR10010035 May 2010	South Jersey Gas Co.	New Jersey	Rate Counsel	Rate of Return
354.	P-2010-2157862 May 2010	Pennsylvania Power Co.	Pennsylvania	Consumer Advocate	Default Service Program
355.	10-CV-2275 June 2010	Xcel Energy	U.S. District Court Minnesota	U.S. Dept. Justice/EPA	Clean Air Act Enforcement
356.	WR09120987 June 2010	United Water New Jersey	New Jersey	Rate Counsel	Rate of Return
357.	U-30192, Phase III June 2010	Entergy Louisiana	Louisiana	Staff	Power Plant Cancellation Costs
358.	31299 July 2010	Cleco Power	Louisiana	Staff	Securities Issuances
359.	App. No. 1601162 July 2010	EPCOR Water	Alberta, Canada	Regional Customer Group	Cost of Capital
360.	U-31196 July 2010	Entergy Louisiana	Louisiana	Staff	Purchase Power Contract
361.	2:10-CV-13101 August 2010	Detroit Edison	U.S. District Court Eastern Michigan	U.S. Dept. of Justice/EPA	Clean Air Act Enforcement
362.	U-31196 August 2010	Entergy Louisiana Entergy Gulf States	Louisiana	Staff	Generating Unit Purchase and Cost Recovery
363.	Case No. 9233 October 2010	Potomac Edison Company	Maryland	Energy Administration	Merger Issues
364.	2010-2194652 November 2010	Pike County Light & Power	Pennsylvania	Consumer Advocate	Default Service Plan

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	Docket Number	Utility	Jurisdiction	Client	Subject
365.	2010-2213369 April 2011	Duquesne Light Company	Pennsylvania	Consumer Advocate	Merger Issues
366.	U-31841 May 2011	Entergy Gulf States	Louisiana	Staff	Purchase Power Agreement
367.	11-06006 September 2011	Nevada Power	Nevada	U. S. Department of Energy	Cost of Capital
368.	9271 September 2011	Exelon/Constellation	Maryland	MD Energy Administration	Merger Savings
369.	4255 September 2011	United Water Rhode Island	Rhode Island	Division of Public Utilities	Rate of Return
370.	P-2011-2252042 October 2011	Pike County Light & Power	Pennsylvania	Consumer Advocate	Default service plan
371.	U-32095 November 2011	Southwestern Electric Power Company	Louisiana	Commission Staff	Wind energy contract
372.	U-32031 November 2011	Entergy Gulf States Louisiana	Louisiana	Commission Staff	Purchased Power Contract
373.	U-32088 January 2012	Entergy Louisiana	Louisiana	Commission Staff	Coal plant evaluation
374.	R-2011-2267958 February 2012	Aqua Pa.	Pennsylvania	Office of Consumer Advocate	Cost of capital
375.	P-2011-2273650 February 2012	FirstEnergy Companies	Pennsylvania	Office of Consumer Advocate	Default service plan
376.	U-32223 March 2012	Cleco Power	Louisiana	Commission Staff	Purchase Power Contract and Rate Recovery
377.	U-32148 March 2012	Entergy Louisiana Energy Gulf States	Louisiana	Commission Staff	RTO Membership
378.	ER11080469 April 2012	Atlantic City Electric	New Jersey	Rate Counsel	Cost of capital
379.	R-2012-2285985 May 2012	Peoples Natural Gas Company	Pennsylvania	Office of Consumer Advocate	Cost of capital

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	Docket Number	Utility	Jurisdiction	Client	Subject
380.	U-32153 July 2012	Cleco Power	Louisiana	Commission Staff	Environmental Compliance Plan
381.	U-32435 August 2012	Entergy Gulf States Louisiana LLC	Louisiana	Commission Staff	Cost of equity
382.	ER-2012-0174 August 2012	Kansas City Power & Light Company	Missouri	U. S. Department of Energy	Rate of return
383.	U-31196 August 2012	Entergy Louisiana/ Entergy Gulf States	Louisiana	Commission Staff	Power Plant Joint Ownership
384.	ER-2012-0175 August 2012	KCP&L Greater Missouri Operations	Missouri	U.S. Department of Energy	Rate of Return
385.	4323 August 2012	Narragansett Electric Company	Rhode Island	Division of Public Utilities Utilities and Carriers	Rate of Return (electric and gas)

BEFORE THE

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

PUBLIC UTILITIES COMMISSION

RE: INVESTIGATION OF	**)**	
NARRAGANSETT ELECTRIC	**)**	
COMPANY d/b/a/ NATIONAL GRID'S	**)**	**DOCKET NO. 4323**
PROPOSED CHANGES TO ELECTRIC	**)**	
AND GAS DISTRIBUTION RATES	**)**	

SCHEDULES ACCOMPANYING THE
DIRECT TESTIMONY OF
MATTHEW I. KAHAL

ON BEHALF OF THE

DIVISION OF PUBLIC UTILITIES AND CARRIERS

AUGUST 30, 2012

NARRAGANSETT ELECTRIC COMPANY

Provisional Rate of Return Summary for Electric Service

Capital Type	% of Total[1]	Cost Rate	Weighted Cost
Long-Term Debt	51.79%	5.11%[2]	2.65%
Preferred Stock	0.17	4.50[2]	0.01
Short-Term Debt	1.30	0.8[2]	0.01
Common Equity	46.74	9.5[3]	4.44
Total	100.00%	--	7.11%

1 See page 3 of this schedule.

2 Schedule RBH-10, page 1 of 1.

3 See attached testimony and Schedules MIK-4 through MIK-6.

NARRAGANSETT ELECTRIC COMPANY

Provisional Rate of Return Summary for Gas Service

Capital Type	% of Total[1]	Cost Rate	Weighted Cost
Long-Term Debt	51.79%	5.65[2]	2.93%
Preferred Stock	0.17	4.50[2]	0.01
Short-Term Debt	1.30	0.8[3]	0.01
Common Equity	46.74	9.5[4]	4.44
Total	100.00%	--	7.39%

1 See page 3 of this schedule.

2 Calculated assuming all gas FMBs are directly assigned to gas ($54.339 million @ 8.05%) plus gas service is assigned 39 percent of Narragansett remaining debt ($239.853 million @ 5.11%). The 39 percent is the gas rate base/gas + electric rate base per Horan page 25.

3 Schedule RBH-10, page 1 of 1.

4 See attached testimony and Schedules MIK-4 through MIK-6.

NARRAGANSETT ELECTRIC COMPANY

Capital Structure at December 31, 2011
($000)

Capital Type	Actual Balance	Adjustments	Adjusted Balance	%
Long-Term Debt	$ 604,339	+$150,000	$ 954,339	51.79%
Preferred Stock	2,454	--	2,454	0.17
Short-Term Debt	168,950	(150,000)	18,950	1.30
Common Equity	1,405,525	(724,810)	680,715	46.74
Total	$2,181,268	$(724,810)	$1,456,458	100.0%

Sources: Narragansett Electric Company actual balance sheet at December 31, 2011 and Schedule RBH-8, page 1 of 1

NARRAGANSETT ELECTRIC COMPANY

Trends in Capital Costs

	Annualized Inflation (CPI)	10-Year Treasury Yield	3-Month Treasury Yield	Single A Utility Yield
2001	2.9%	5.0%	3.5%	7.8%
2002	1.6	4.6	1.6	7.4
2003	1.9	4.1	1.0	6.6
2004	2.7	4.3	1.4	6.2
2005	3.4	4.3	3.0	5.6
2006	2.5	4.8	4.8	6.1
2007	2.8	4.6	4.5	6.3
2008	3.8	3.4	1.6	6.5
2009	(0.4)	3.2	0.2	6.0
2010	1.6	3.2	0.1	5.5
2011	3.1	2.8	0.0	5.1

NARRAGANSETT ELECTRIC COMPANY

U.S. Historic Trends in Capital Costs
(Continued)

	Annualized Inflation (CPI)	10-Year Treasury Yield	3-Month Treasury Yield	Single A Utility Yield
2007				
January	2.1%	4.8%	5.1%	6.0%
February	2.4	4.7	5.2	5.9
March	2.8	4.6	5.1	5.9
April	2.6	4.7	5.0	6.0
May	2.7	4.8	5.0	6.0
June	2.7	5.1	5.0	6.3
July	2.4	5.0	5.0	6.3
August	2.0	4.7	4.3	6.2
September	2.8	4.5	4.0	6.2
October	3.5	4.5	4.0	6.1
November	4.3	4.2	3.4	6.0
December	4.1	4.1	3.1	6.2
2008				
January	4.3%	3.7%	2.8%	6.0%
February	4.0	3.7	2.2	6.2
March	4.0	3.5	1.3	6.2
April	3.9	3.7	1.3	6.3
May	4.2	3.9	1.8	6.3
June	5.0	4.1	1.9	6.4
July	5.6	4.0	1.7	6.4
August	5.4	3.9	1.8	6.4
September	4.9	3.7	1.2	6.5
October	3.7	3.8	0.7	7.6
November	1.1	3.5	0.2	7.6
December	0.1	2.4	0.0	6.5

NARRAGANSETT ELECTRIC COMPANY

U.S. Historic Trends in Capital Costs
(Continued)

	Annualized Inflation (CPI)	10-Year Treasury Yield	3-Month Treasury Yield	Single A Utility Yield
2009				
January	0.0%	2.5%	0.1%	6.4%
February	0.2	2.9	0.3	6.3
March	(0.4)	2.8	0.2	6.4
April	(0.7)	2.9	0.2	6.5
May	(1.3)	2.9	0.2	6.5
June	(1.4)	3.7	0.2	6.2
July	(2.1)	3.6	0.2	6.0
August	(1.5)	3.6	0.2	5.7
September	(1.3)	3.4	0.1	5.5
October	(0.2)	3.4	0.1	5.6
November	1.8	3.4	0.1	5.6
December	2.5	3.6	0.1	5.8
2010				
January	2.6%	3.7%	0.1%	5.8%
February	2.1	3.7	0.1	5.9
March	2.3	3.7	0.2	5.8
April	2.2	3.9	0.2	5.8
May	2.0	3.4	0.2	5.5
June	1.1	3.2	0.1	5.5
July	1.2	3.0	0.2	5.3
August	1.1	2.7	0.2	5.0
September	1.1	2.7	0.2	5.0
October	1.2	2.5	0.1	5.1
November	1.1	2.8	0.1	5.4
December	1.2	3.3	0.1	5.6

NARRAGANSETT ELECTRIC COMPANY

U.S. Historic Trends in Capital Costs
(Continued)

	Annualized Inflation (CPI)	10-Year Treasury Yield	3-Month Treasury Yield	Single A Utility Yield
2011				
January	1.6%	3.4%	0.1%	5.6%
February	2.1	3.6	0.1	5.7
March	2.7	3.4	0.1	5.6
April	2.2	3.5	0.1	5.6
May	3.6	3.2	0.0	5.3
June	3.6	3.0	0.0	5.3
July	3.6	3.0	0.0	5.3
August	3.8	2.3	0.0	4.7
September	3.9	2.0	0.0	4.5
October	3.5	2.2	0.0	4.5
November	3.0	2.0	0.0	4.3
December	3.0	2.0	0.0	4.3
2012				
January	2.9	2.0	0.0	4.3
February	2.9	2.0	0.0	4.4
March	2.7	2.2	0.1	4.5
April	2.3	2.1	0.1	4.4
May	1.7	1.8	0.1	4.2
June	1.7	1.6	0.1	4.1

Source: *Economic Report of the President, Mergent's Bond Record, Federal Reserve Statistical Release* (H.15), *Consumer Price Index Summary* (BLS)

NARRAGANSETT ELECTRIC COMPANY

Listing of the Gas Distribution Utility Proxy Companies

	Company	Safety Rating	Financial Strength	Beta	2011 Common Equity Ratio*
1.	AGL Resources	1	A	0.75	48.0%
2.	Atmos Energy	2	B++	0.70	50.6
3.	LaClede Group	2	B++	0.55	61.1
4.	New Jersey Resources	1	A	0.65	64.5
5.	NW Natural Gas	1	A	0.60	52.7
6.	Piedmont Natural	2	B++	0.70	59.6
7.	South Jersey Ind.	2	B++	0.65	59.5
8.	Southwest Gas	3	B	0.75	56.8
9.	WGL Corporation	1	A	0.65	66.2
	Average	**1.7**	**--**	**0.67**	**57.7%**

* The common equity ratio excludes short-term debt (and current maturities of long-term debt). Actual 2011 equity ratio including short-term debt and current maturities averages 50.8 percent.

Source: *Value Line Investment Survey*, June 8, 2012.

NARRAGANSETT ELECTRIC COMPANY

List of the Electric Distribution Utility Proxy Companies

	Company	Safety Rating	Financial Strength	Beta	2011 Common Equity Ratio*
1.	C.H. Energy Corporation	1	A	0.65	51.8%
2.	Centerpoint Energy	3	B+	0.80	32.8
3.	Consolidated Edison	1	A+	0.60	52.5
4.	Northeast Utilities	2	B++	0.70	45.3
5.	PEPCO Holdings	3	B	0.75	53.3
6.	UIL Holdings	2	B++	0.70	41.4
	Average	**2.0**	**--**	**0.70**	**46.2%**

* The common equity ratio excludes short-term debt (and current maturities of long-term debt). Actual 2011 equity ratio including short-term debt and current maturities would be somewhat lower.

Source: *Value Line Investment Survey,* May 25 and June 22, 2012.

NARRAGANSETT ELECTRIC COMPANY

Risk Indicators for the Electric Utility Vertically-Integrated Proxy Group

	Company	Safety Rating	Financial Strength	Beta	2011 Common Equity Ratio*
1.	Allete	2	A	0.70	55.7%
2.	Alliant Energy	2	A	0.75	50.9
3.	Ameren	3	B++	0.80	53.7
4.	Am. Electric Power	3	B++	0.70	49.3
5.	Avista	2	A	0.70	48.6
6.	Black Hills Corp.	3	B+	0.85	48.6
7.	Cleco Corp.	1	A	0.65	51.5
8.	DTE Energy	3	B+	0.75	49.4
9.	Edison Int.	3	B++	0.80	40.6
10.	Great Plains Energy	3	B+	0.75	51.6
11.	Hawaiian Electric	3	B+	0.70	53.9
12.	Idacorp.	3	B+	0.70	54.4
13.	Integris Energy	2	B++	0.90	60.6
14.	Pinnacle West	2	B++	0.70	55.9
15.	Otter Tail	3	B+	0.90	54.0
16.	Portland General	2	B++	0.75	50.4
17.	PG&E Corp.	3	B++	0.55	50.2
18.	SCANA Corp.	2	B++	0.70	45.7
19.	Sempra Energy	2	A	0.80	49.2
20.	Southern Co.	1	A	0.55	47.1
21.	TECO Energy	2	B++	0.85	45.8
22.	Vectren	2	A	0.75	48.4
23.	Weston Energy	2	B++	0.75	50.0
24.	Wisconsin Energy	1	A	0.65	46.0
25.	Xcel Energy	2	B++	0.65	48.9
	Average	**2.3**	**--**	**0.73**	**50.4%**

* The common equity ratio excludes short-term debt (and current maturities of long-term debt). Actual 2011 equity ratio including short-term debt and current maturities would be slightly lower.

Source: *Value Line Investment Survey*, May 4, 25 and June 22, 2012.

NARRAGANSETT ELECTRIC COMPANY

DCF Summary for
Electric Distribution Utility Proxy Group

1. Dividend Yield (January – June 2012)	4.42%[1]
2. Adjusted Yield ((1) x 1.0225)	4.5%
3. Long-Term Growth Rate	4.0 – 5.0%[2]
4. Total Return ((2) + (3))	8.5 – 9.5%
5. Flotation Adjustment	0.0%
6. Cost of Equity ((4) + (5))	8.5-9.5%
7. Midpoint	9.0%
Recommendation	**9.5%**

(1) Schedule MIK-4, page 2 of 4. (Excludes C.H. Energy)
(2) Schedule MIK-4, page 3 of 4.

NARRAGANSETT ELECTRIC COMPANY

Dividend Yields for the Electric
Utility Distribution Group
(January – June 2012)

	Company	January	February	March	April	May	June	Average
1.	C.H. Energy	3.9%	3.8%	--	--	--	--	3.85%
2.	Centerpoint Energy	4.4	4.2	4.1	4.0	4.0	3.9	4.10
3.	Consolidated Edison	4.1	4.2	4.1	4.1	4.0	3.9	4.07
4.	Northeast Utilities	3.2	3.3	3.2	3.2	3.8	3.5	3.37
5.	Pepco Holdings	5.5	5.6	5.7	5.7	5.7	5.5	5.62
6.	UIL Holdings	5.0	4.9	5.0	5.0	5.1	4.8	4.97
	Average	**4.35%**	**4.33%**	**4.42%**	**4.40%**	**4.52%**	**4.32%**	**4.33%**
	Average without C.H. Energy	**4.44%**	**4.44%**	**4.42%**	**4.40%**	**4.52%**	**4.32%**	**4.42%**

Note: C.H. Energy February 2012 dividend yield is based on February 17 stock price, not end of month due to merger announcement on February 21, 2012.

*Source: Standard & Poors *Stock Guide*, February – July 2012.

NARRAGANSETT ELECTRIC COMPANY

Projection of Earnings Per Share
Five-Year Growth Rates for the
Electric Distribution Company Proxy Group

	Company	Value Line	Yahoo	MSN	Reuters	CNN	Average
1.	C.H. Energy	2.5%	NA	NA	NA	4.0%	3.25%
2.	Centerpoint Energy	4.0	4.9	5.1	5.14	5.3	4.89
3.	Consolidated Edison	4.0	3.02	3.4	3.23	3.3	3.39
4.	Northeast Utilities	8.0	4.92	6.6	5.67	5.75	6.19
5.	Pepco Holdings	7.0	4.75	3.8	4.83	6.0	5.27
6.	UIL Holdings	4.0	4.10	4.5	4.25	5.0	4.37
	Average	**4.92%**	**4.34%**	**4.68%**	**4.62%**	**4.89%**	**4.56%**
	Average without C.H. Energy	**5.40%**	**4.34%**	**4.68%**	**4.62%**	**5.07%**	**4.82%**

Source: *Value Line Investment Survey*, May 25 and June 22, 2012. YahooFinance.com, MSNMoney.com, Reuters.com, CNNfn.com, public websites, August 2012.

NARRAGANSETT ELECTRIC COMPANY

Other *Value Line* Growth Measures for the
Electric Distribution Utility Proxy Group

	Company	Dividend per Share	Book Value per Share	Earnings Retention
1.	C. H. Energy	0.5%	2.0%	3.0%
2.	Centerpoint Energy	2.5	7.0	4.5
3.	Consolidated Edison	1.0	8.0	4.0
4.	Northeast Utilities	9.0	8.5	4.5
5.	PEPCO Holdings	1.0	2.0	2.5
6.	UIL Holdings	0.0	3.5	3.0
	Average	**2.33%**	**5.17%**	**3.58%**
	Average without C.H. Energy	**2.70%**	**5.80%**	**3.70%**

Source: *Value Line Investment Survey*, May 25 and June 22, 2012.

NARRAGANSETT ELECTRIC COMPANY

Fundamental Growth Rate Analysis for
Electric Distribution Utility Proxy Group

		Shares 2011-2016[1]	% Premium[2]	sv[3]	br[4]	sv + br
1.	C. H. Energy	0.00%	--	0.0%	3.0%	3.0%
2.	Centerpoint Energy	0.23	104.8%	0.2	4.5	4.7
3.	Consolidated Edison	0.00	--	--	4.0	4.0
4.	Northeast Utilities	0.00	--	--	4.5	4.5
5.	PEPCO Holdings	2.31	(2.2)	--	2.5	2.5
6.	UIL Holdings	0.14	54.37	0.1	3.0	3.1
	Average			**0.1%**	**3.6%**	**3.7%**
	Average without C.H. Energy			**0.2%**	**3.7%**	**3.9%**

[1] Projected annualized growth rate in share outstanding, 2011-2016.
[2] **%** Premium of share price ("Recent Price") over 201 Book Value per share.
[3] **sv** is growth rate in shares x % premium.
[4] **br** is Value Line's projection as of 2015-2017.

Source: *Value Line Investment Survey*, May 25 and June 22, 2012.

NARRAGANSETT ELECTRIC COMPANY

DCF Summary for
Gas Distribution Utility Proxy Group

1. Dividend Yield (January 2012 – June 2012)	3.73%[1]
2. Adjusted Yield ((1) x 1.0275)	3.8%
3. Long-Term Growth Rate	5.0 – 6.0%[2]
4. Total Return ((2) + (3))	8.8 – 9.8%
5. Flotation Expense	0.0%
6. Cost of Equity ((4) + (5))	8.8 – 9.8%
7. Midpoint	9.3%
Recommendation	**9.5%**

[1] Schedule MIK-4, page 2 of 5.

[2] Schedule MIK-4, pages 3 of 5, 4 of 5 and 5 of 5.

NARRAGANSETT ELECTRIC COMPANY

Dividend Yields for Gas Distribution Utility Proxy Group
(January 2012 – June 2012)

	Company	January	February	March	April	May	June	Average
1.	AGL Resources	4.4%	4.5%	4.6%	4.6%	4.9%	4.7%	4.53%
2.	Atmos Energy	4.3	4.5	4.4	4.2	4.2	3.9	4.35
3.	LaClede Group	4.0	4.0	4.3	4.2	4.4	4.2	4.13
4.	New Jersey Resources	3.2	3.3	3.4	3.5	3.6	3.5	3.35
5.	Northwest Natural Gas	3.7	3.9	3.9	3.9	3.8	3.7	3.85
6.	Piedmont Natural	3.5	3.6	3.9	3.9	4.0	3.7	3.73
7.	South Jersey Ind.	2.9	3.1	3.2	3.3	3.3	3.2	3.13
8.	Southwest Gas	2.5	2.8	2.8	2.8	2.8	2.7	2.73
9.	WGL Corporation	3.6	3.8	3.9	4.0	4.1	4.0	3.83
	Average	**3.57%**	**3.72%**	**3.82%**	**3.83%**	**3.90%**	**3.73%**	**3.73%**

Source: S&P *Stock Guide*, February 2012 – July 2012.

NARRAGANSETT ELECTRIC COMPANY

Projection of Earnings per Share
Five-Year Growth Rates for the
Gas Distribution Utility Proxy Group

	Company	Value Line	Yahoo	MSN	Reuters	CNN	Average
1.	AGL Resources	5.5%	(5.7%)*	4.3%	5.03%	4.00%	4.71%
2.	Atmos Energy	4.0	4.37	5.0	5.37	6.15	4.98
3.	LaClede Group	2.0	5.30	3.0	5.00	3.5	3.76
4.	New Jersey Resources	5.5	2.47	3.2	3.10	2.6	3.37
5.	Northwest Natural Gas	4.0	4.5	4.1	4.17	3.75	4.10
6.	Piedmont Natural	2.5	4.55	4.7	5.15	5.4	4.46
7.	South Jersey Ind.	9.0	9.00	6.0	8.00	6.0	7.60
8.	Southwest Gas	9.0	4.15	4.4	2.58	1.6	4.35
9.	WGL Corporation	3.0	4.8	4.9	4.80	3.85	4.27
	Average	**4.94%**	**4.89%**	**4.40%**	**4.80%**	**4.09%**	**4.62%**

Sources: *Value Line Investment Survey*, June 8, 2012. YahooFinance.com, MSNMoney.com, CNNfn.com, Reuters.com, public websites, July 2012.

* The large, negative growth rate published by YahooFinance.com appears to be anomalous and inconsistent with other published sources. For that reason, it is excluded from the reported averages.

NARRAGANSETT ELECTRIC COMPANY

Other Value Line Measure of
Growth for the Gas Distribution Utility Proxy Group

	Company	Dividend Per Share	Book Value Per Share	Earnings Retention
1.	AGL Resources	2.0%	6.0%	6.0%
2.	Atmos Energy	1.5	6.0	3.5
3.	LaClede Group	2.5	4.5	4.5
4.	New Jersey Resources	4.0	5.5	7.5
5.	Northwest Natural Gas	3.0	4.5	5.0
6.	Piedmont Natural	3.5	1.5	3.5
7.	South Jersey Ind.	9.0	6.5	7.5
8.	Southwest Gas	8.0	6.5	6.0
9.	WGL Corporation	2.5	4.0	3.5
	Average	**4.00%**	**5.00%**	**5.22%**

Source: *Value Line Investment Survey*, June 8, 2012. The earnings retention figures are projections for 2015-2017.

NARRAGANSETT ELECTRIC COMPANY

Fundamental Growth Rate Analysis
for Gas Distribution Utility Proxy Group

		Shares 2011-2016[1]	% Premium[2]	sv[3]	br[4]	sv + br
1.	AGL Resources	0.67%	24.9%	0.2%	6.0%	6.2%
2.	Atmos Energy	2.67	14.4	0.4	3.5	3.9
3.	LaClede Group	2.19	47.7	1.0	4.5	5.5
4.	New Jersey Resources	Negative	NA	0.0	7.5	7.5
5.	Northwest Natural Gas	2.99	66.8	2.0	5.0	7.0
6.	Piedmont Natural	Negative	NA	0.0	3.5	3.5
7.	South Jersey Ind.	2.99	105.0	3.1	7.5	10.6
8.	Southwest Gas	2.10	41.0	0.9	6.0	6.9
9.	WGL Corporation	0.31	57.8	0.2	3.5	3.7
	Average			**0.86%**	**5.22%**	**6.09%**

(1) Projected growth rate in shares outstanding, 2011-2016.

(2) % Premium of share price ("Recent Price") over 2012 Book Value per share.

(3) SV is growth rate in shares x % premium.

(4) br is Value Line's projection as of 2015-2017.

Source: *Value Line Investment Survey*, June 8, 2012.

NARRAGANSETT ELECTRIC COMPANY

DCF Summary for
Electric Utility Vertically-Integrated Proxy Group

1. Dividend Yield (January 2012 – June 2012)	4.28%[1]
2. Adjusted Yield ((1) x 1.025)	4.4%
3. Long-Term Growth Rate	4.5 – 5.5%[2]
4. Total Return ((2) + (3))	8.9 – 9.9%
5. Flotation Expense	0.0%
6. Cost of Equity ((4) + (5))	8.9 – 9.9%
7. Midpoint	9.4%
Recommendation	**9.5%**

(1) Schedule MIK-6, page 2 of 5.

(2) Schedule MIK-6, pages 3 of 5, 4 of 5 and 5 of 5.

NARRAGANSETT ELECTRIC COMPANY

Dividend Yields for the Electric Utility Vertically-Integrated Proxy Group
(January 2012 – June 2012)

	Company	January	February	March	April	May	June	Average
1.	Allete	4.4%	4.4%	4.4%	4.5%	4.7%	4.4%	4.47%
2.	Alliant	4.2	4.2	4.2	4.0	4.1	3.9	4.10
3.	Ameren	5.1	5.0	4.9	4.9	5.0	4.8	4.95
4.	Amer. Electric	4.8	5.0	4.9	4.8	4.9	4.7	4.85
5.	Avista	4.3	4.7	4.5	4.4	4.6	4.3	4.47
6.	Black Hills	4.4	4.5	4.4	4.5	4.6	4.6	4.50
7.	Cleco Corp.	3.1	3.2	3.2	3.1	3.1	3.0	3.12
8.	DTE Energy	4.4	4.4	4.3	4.2	4.1	4.2	4.27
9.	Edison Int.	3.2	3.1	3.1	3.0	2.9	2.8	3.02
10.	Great Plains	4.1	4.3	4.2	4.2	4.3	4.0	4.18
11.	Hawaiian	4.8	5.0	4.9	4.7	4.5	4.3	4.70
12.	Ida Corp	3.1	3.3	3.2	3.2	3.4	3.1	3.22
13.	Integris	5.2	5.2	5.1	5.0	5.0	4.8	5.05
14.	Pinnacle West	4.4	4.5	4.4	4.3	4.3	4.1	4.33
15.	Otter Tail	5.4	5.6	5.5	5.4	5.6	5.2	5.45
16.	Portland Gen.	4.3	4.3	4.2	4.1	4.3	4.1	4.22
17.	PG&E Corp.	4.5	4.4	4.2	4.1	4.2	4.0	4.23
18.	SCANA Corp	4.3	4.4	4.3	4.3	4.2	4.1	4.27
19.	Sempra	3.4	4.1	4.0	3.7	3.7	3.5	3.73
20.	Southern Co.	4.1	4.3	4.2	4.3	4.3	4.2	4.23
21.	TECO Energy	4.8	4.9	5.0	4.9	5.1	4.9	4.93
22.	Vectren	4.9	4.8	4.8	4.8	4.8	4.7	4.80
23.	Westar Energy	4.5	4.8	4.7	4.6	4.6	4.4	4.60
24.	Wisconsin Energy	3.5	3.5	3.4	3.3	3.2	3.0	3.32
25.	Xcel Energy	3.9	3.9	3.9	3.8	3.9	3.8	3.87
	Average	**4.28%**	**4.39%**	**4.31%**	**4.24%**	**4.30%**	**4.12%**	**4.28%**

Source: S&P *Stock Guide*, February 2012 – July 2012.

NARRAGANSETT ELECTRIC COMPANY

Projection of Earnings per Share
Five-Year Growth Rates for the
Electric Utility Vertically-Integrated Proxy Group

	Company	Value Line	Yahoo	MSN	Reuters	CNN	Average
1.	Allete	7.5%	5.00%	5.0%	6.50%	4.65%	5.73%
2.	Alliant Energy	6.0	6.30	6.2	5.92	6.30	6.14
3.	Ameren	-1.0	-3.00	-0.5	-4.50	-4.50	-2.70
4.	AEP	4.5	3.56	3.6	4.05	4.00	3.94
5.	Avista	5.5	4.00	4.7	4.50	5.00	4.74
6.	Black Hills	7.0	6.00	6.0	2.20	6.00	5.44
7.	Cleco Corp.	6.5	3.00	n/a	3.00	3.00	3.88
8.	DTE Energy	4.0	4.51	5.0	3.83	4.30	4.33
9.	Edison Int.	1.0	0.33	3.8	2.48	2.70	2.06
10.	Great Plains	5.5	9.75	7.8	8.50	5.00	7.31
11.	Hawaiian Elec.	9.0	9.15	7.1	6.57	8.70	8.10
12.	IdaCorp	3.0	4.00	5.0	4.50	4.50	4.20
13.	Integris	7.0	5.0	4.7	7.2	4.0	5.58
14.	Pinnacle West	5.0	6.34	5.7	6.12	5.25	5.68
15.	Otter Tail	24.0	5.0	5.0	5.0	5.0	8.80
16.	Portland Gen.	5.5	3.67	4.1	4.25	4.50	4.40
17.	PG&E Corp.	4.5	0.53	2.6	2.75	1.40	2.36
18.	SCANA Corp	4.0	4.50	4.7	4.62	4.70	4.50
19.	Sempra Energy	4.5	7.00	6.8	6.50	4.95	5.95
20.	Southern Co.	5.0	5.40	5.0	5.51	5.40	5.26
21.	TECO Energy	7.5	3.12	3.1	4.56	2.60	4.18
22.	Vectren	6.5	5.00	4.5	5.50	5.00	5.30
23.	Westar Energy	6.5	4.60	6.2	5.55	5.60	5.69
24.	Wisconsin Energy	6.5	6.05	5.3	6.86	5.00	5.94
25.	Xcel Energy	6.0	5.06	4.9	4.92	5.00	5.18
	Average	**6.04%**	**4.56%**	**4.85%**	**4.67%**	**4.32%**	**4.88%**

Sources: *Value Line Investment Survey*, May 4, 25 and June 22, 2012. YahooFinance.com, MSNMoney.com, CNNfn.com, Reuters.com, public websites, July 2012.

NARRAGANSETT ELECTRIC COMPANY

Other Value Line Measure of
Growth for the Electric Utility Vertically-Integrated Proxy Group

	Company	Dividends Per Share	Book Value Per Share	2015 - 2017 Earnings Retention Growth Rate
1.	Allete	2.0%	4.0%	4.0%
2.	Alliant Energy	5.5	3.5	3.5
3.	Ameren	2.5	0.5	2.0
4.	Am. Electric Power	3.5	4.5	4.0
5.	Avista	6.5	3.5	3.5
6.	Black Hills Corp.	2.0	2.0	3.0
7.	Cleco Corp.	11.5	6.0	5.0
8.	DTE Energy	3.5	3.5	3.5
9.	Edison Int.	3.0	4.0	5.5
10.	Great Plains Energy	5.0	2.0	3.0
11.	Hawaiian Electric	1.0	5.5	3.0
12.	Ida Corp.	8.0	5.5	4.0
13.	Integris	0.5	2.5	3.5
14.	Pinnacle West	2.5	3.5	3.5
15.	Otter Tail	1.5	1.5	3.0
16.	Portland General	3.5	4.0	4.0
17.	PG&E Corp.	2.0	4.0	5.0
18.	SCANA Corp.	2.0	5.5	4.0
19.	Sempra Energy	9.0	5.0	6.0
20.	Southern Co.	4.0	5.5	4.0
21.	TECO Energy	5.0	4.5	5.0
22.	Vectren	2.5	3.0	4.5
23.	Westar	3.0	4.5	3.5
24.	Wisconsin Energy	13.5	3.5	5.5
25.	Xcel Energy	5.0	4.5	3.5
	Average	**4.32%**	**3.84%**	**3.96%**

Source: *Value Line Investment Survey*, May 4, 25 and June 22, 2012.

NARRAGANSETT ELECTRIC COMPANY

Fundamental Growth Rate Analysis
for Electric Utility Proxy Group

	Company	2011-2016[1]	Premium[2]	sv[3]	br[4]	sv + br
1.	Allete	1.55%	36.0%	0.6%	4.0%	4.6%
2.	Alliant Energy	0.88	53.1	0.5	3.5	4.0
3.	Ameren	-1.49	3.7	-0.1	2.0	1.9
4.	AEP	0.68	25.5	0.2	4.0	4.2
5.	Avista	1.20	23.5	0.3	3.5	3.8
6.	Black Hills	0.49	16.6	0.1	3.0	3.1
7.	Cleco Corp.	0.23	67.3	0.2	5.0	5.2
8.	DTE Energy	1.35	36.4	0.5	3.5	4.0
9.	Edison Int.	0.00	32.8	0.0	5.5	5.5
10.	Great Plains	2.50	-5.3	-0.1	3.0	2.9
11.	Hawaiian Electric	7.83	59.0	4.6	3.0	7.6
12.	IdaCorp.	0.42	12.5	0.1	4.0	4.1
13.	Integris	0.00	--	0.0	3.5	3.5
14.	Pinnacle West	1.64	33.1	0.5	3.5	4.0
15.	Otter Tail	3.07	39.3	1.2	3.0	4.2
16.	Portland Gen.	0.30	10.7	0.0	4.0	4.0
17.	PG&E Corp.	1.08	51.4	0.6	5.0	5.6
18.	SCANA Corp	4.24	46.2	2.0	4.0	6.0
19.	Sempra Energy	0.50	49.7	0.2	6.0	6.2
20.	Southern Co.	1.67	114.7	1.9	4.0	5.9
21.	TECO Energy	0.48	60.4	0.3	5.0	5.3
22.	Vectren	1.45	58.8	0.9	4.5	5.4
23.	Westar Energy	1.44	25.6	0.4	3.5	3.9
24.	Wisconsin Energy	-0.66	116.5	-0.8	5.5	4.7
25.	Xcel Energy	1.15	47.2	0.5	3.5	4.0
	Average			**0.6%**	**4.0%**	**4.6%**

(1) Projected growth rate in shares outstanding, 2011-2016.

(2) % Premium of share price (“Recent Price”) over 2011 Book Value per share.

(3) SV is growth rate in shares x % premium.

(4) br is Value Line’s projection as of 2015-2017.

Source: *Value Line Investment Survey*, May 4, 25 and June 22, 2012.

NARRAGANSETT ELECTRIC COMPANY

Capital Asset Pricing Model Study
Illustrative Calculations

A. Model Specification

$K_e = R_F + \beta\ (R_m - R_F)$, where

K_e = cost of equity

R_F = return on risk free asset

Rm = expected stock market return

B. Data Inputs

R_F = 3.0% (Treasury bond yield for the most recent six months, see page 2 of 2)

Rm = 8.0 – 11.0% (equates to equity risk premium of 5.0 - 8.0%)

Beta = 0.70 (Based on range 0.67 to 0.73, per Schedule MIK-3)

C. Model Calculations

Low end:	K_e = 3.0% + 0.70 (5.0) = 6.5%
Midpoint:	K_e = 3.0% + 0.70 (6.5) = 7.6%
Upper End:	K_e = 3.0% + 0.70 (8.0) = 8.6%
High Sensitivity:	K_e = 3.0% + 0.70 (9.0) = 9.3%

NARRAGANSETT ELECTRIC COMPANY

Long-Term Treasury Yields
(January 2012 - June 2012)

Month	30-Year	20-Year	10-Year
January 2012	3.03	2.70	1.97
February	3.11	2.75	1.97
March	3.28	2.94	2.17
April	3.18	2.82	2.05
May	2.93	2.53	1.80
June	2.70	2.31	1.62
Average	3.04%	2.68%	1.93%

Source: Federal Reserve, “Statistical Release,” publication H.15, February 2012 – July 2012.