BEFORE THE

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

PUBLIC UTILITIES COMMISSION

RE: INVESTIGATION OF NARRAGANSETT ELECTRIC COMPANY d/b/a/ NATIONAL GRID FOR APPROVAL OF A CHANGE IN ELECTRIC AND GAS DISTRIBUTION RATES	**)))))**	**DOCKET NO. 4770**

DIRECT TESTIMONY OF

MATTHEW I. KAHAL

ON BEHALF OF THE

DIVISION OF PUBLIC UTILITIES AND CARRIERS

APRIL 6, 2018

TABLE OF CONTENTS

PAGE

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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 1108 Pheasant Crossing, Charlottesville, Virginia 22901.

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 35 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 430 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 various other regulatory policy issues. These cases have involved electric, gas, water and telephone 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, the Ohio Consumers Counsel, the New Hampshire Consumer Advocate, Maryland Department of Natural Resources and Energy Administration, and private sector clients.

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 and 2012 electric/gas base rate cases (Docket Nos. 4065 and 4323). 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 have assisted the Division with Narragansett's applications in 2012 and 2017 for authority to issue long-term debt (Division Docket Nos. D-12-12 and D-17-36). The Company's 2017 debt issue Application has been recently resolved by a settlement agreement approved by the Division.

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-14, page 1 of 1, the Company requests an authorized overall rate of return of 7.43 percent on its electric rate base and 7.67 percent on its gas rate base. The proposed capital structure based on the Company's actual balance sheet as of June 30, 2017 with certain adjustments, including a large adjustment to reflect a new issuance of long-term debt planned for later this year. (Please see Section III of my testimony for a description of these adjustments.) This results in a proposed capital structure consisting of 48.5 percent long-term debt, 0.45 percent short-term debt, 0.1 percent preferred stock and 51.0 percent common equity. The Company requests a return on the common equity ("ROE") component of 10.1 percent for both electric and gas operations. 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 10.1 percent ROE is nearly a 0.65 percentage points lower than the 10.75 percent ROE requested by the Company in its last rate case in 2012 and 1.5 percentage points lower than in its 2009 rate case. Thus, the Company's request in this case gives recognition to the downward trend in the cost of equity capital for utilities since 2012.

Q. IF THE COMPANY REQUESTS AN IDENTICAL RETURN ON EQUITY OF 10.1 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., 7.43 percent electric versus 7.67 percent gas) is due to differences in the cost of long-term 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 for cost of debt purposes.

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 9.5 percent ROE. The 9.5 percent ROE was set in the Company's 2012 electric and gas rate case resolved in 2012 by settlement approved by the Commission (Docket No. 4323). Thus, the Company's proposal in this case is a large increase in the authorized return on equity (from 9.5 to 10.1 percent), and the Company's proposed capital structure in this case is in slightly more expensive (i.e., higher equity ratio) than the settlement capital structure from the last rate case.

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

A. Yes. The proposed capitalization includes a planned $250 million issue of long-term debt scheduled to take place in later this year at an assumed all-in cost of 3.99 percent. For capital structure purposes, the debt proceeds are assumed to be used partly to reduce the Company's June 2017 short-term debt balance. In addition, the proposed rate of return includes a small amount of short-term debt at a projected cost rate of 1.76 percent. Please note that Narragansett intends to issue the new long-term debt under the authorization recently granted to it by the Division in Docket No. D-17-36 earlier this year. 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 1, I am recommending an overall rate of return on Narragansett's electric utility rate base of 6.60 percent and 7.04 percent on the gas utility rate base. This includes an ROE for gas operations of 9.0 percent and 8.5 percent for electric operations and a capital structure for both gas and electric operations of 47.90 percent long-term debt, 1.11 percent short-term debt, 50.91 percent common equity and 0.1 percent preferred stock. This recommendation is provisional and may change with updating. My capital structure proposal is similar to that recommended by the Company although with slightly less long-term debt and slightly more short-term debt, as discussed in Section III of my testimony. It should be noted that both my capital structure recommendation and that of the Company are slightly more expensive than approved in the 2012 rate case settlement.

Please note that the 51 percent equity ratio that the Company and I are proposing may be somewhat higher than industry averages but well within the range of industry norms. The increase in the equity ratio for ratemaking to 51 percent is an additional reason for the Commission to lower the authorized ROE from the 9.5 percent approved in the last case.

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

A. I do not have an objection, as a general matter, to identifying a single cost of equity for gas and electric operations, as the Company has proposed. Indeed, this approach was approved in the 2012 rate case settlement approved by the Commission. 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 uncertainty ranges of the cost of equity model results for electric and gas utility companies. The actual gas and electric equity cost rates – if not identical – are very similar.

In this case, I am recommending an ROE for electric operations of 8.5 percent versus 9.0 percent for gas operations. I am doing so, not because of differences in the risks of gas versus electric operations, but because the Division is recommending an "asymmetric" Performance Incentive Mechanism ("PIM") program that will provide the electric side operations of Narragansett a reasonable opportunity over the next few years to increase earnings by at least 0.5 percent ROE equivalent and likely far more. In other words, the 8.5 percent ROE on electric rate base anticipates an opportunity to earn at least 9.0 percent with PIM earnings. In the event that the Commission does not approve such a PIM program in this case, then the recommended electric side ROE would be 9.0 percent – identical to that of gas.

In addition to the 8.5 percent electric ROE, my testimony discusses how PIM earnings should be treated for earnings sharing purposes. Assuming the approval of the 8.5 percent electric operations ROE, the PIM earnings should be treated as "below the line" (i.e., belonging to shareholders) for all achieved earnings below 9.5 percent (i.e., 100 basis points above the authorized ROE on the "core" electric rate base). However, if the achieved electric ROE exceeds 9.5 percent, PIM earnings would be treated as above the line (i.e., part of calculated regulatory earnings) and therefore subject to the earnings sharing formula. Please note that I am assuming that there is no PIM program in this case for gas operations.

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

A. I do not object to Company estimates for short-term debt (1.76 percent) and new long-term debt (3.99 percent) cost rates at this time. Those estimates certainly were reasonable at the time the Company filed its case. However, interest rates have moved up somewhat since then, and the Company therefore should revisit and update these estimates, including using actual values if and when available.

I have accepted the 3.99 percent and $250 million of new long-term 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) 4.69 percent cost of long-term debt for electric service and a 5.18 percent long-term debt cost rate for gas service.

While I provisionally accept 4.69 percent as the electric service cost of debt, my cost of debt recommendation does make one small adjustment on the gas side. One of the gas First Mortgage Bonds is due for redemption in March 2018 and therefore should be removed from the cost of debt calculation. This has no effect on the electric operations cost of long-term debt, but it does slightly reduce the (provisional) gas operations cost of debt from 5.18 to 5.10 percent.

Q. WHAT IS THE BASIS OF YOUR 9.0 PERCENT (OR 8.5 PERCENT WITH PIM) RECOMMENDATION FOR THE RETURN ON EQUITY?

A. I am relying primarily upon the standard discounted cash flow ("DCF") model applied to a 22 company electric (and combination electric/gas) proxy group very similar to the 24 company group used by Company cost of equity expert Mr. Hevert. My DCF studies use market data from the six months ending January 2018, obtaining a range of 8.2 to 8.7 percent, with a midpoint of 8.5 percent. My recommendation of 9.0 percent (or 8.5 percent plus PIM earnings) is somewhat above the midpoint and even above the 8.7 percent upper end of this range. The reason for this increase is the evidence that the cost of capital has risen somewhat since the August 2017 to January 2018 recent historic time period of my evidence due to important and noticeable changes in the U.S. economy and capital markets that have occurred since late last year. I discuss these changes later in my testimony. 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. For a variety of reasons I do not regard this method as particularly useful or reliable.

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, and if anything risk has diminished. 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 10.1 percent to 9.0 percent (or 8.5 percent plus PIM earnings), a figure 0.5 percent lower than what this Commission approved for electric service in the 2012 rate case. In addition, I

recommend that PIM earnings be included in earnings sharing in the event that actual electric earnings over the term of the rate plan exceed the authorized ROE by more than 100 basis points.

(2) I have lowered the (provisional) gas service cost of debt from 5.18 to 5.10 percent.

(3) I recommend a slightly lower long-term debt equity ratio of 47.90 percent in place of the requested 48.5 percent, and I also have increased the short-term debt percentage to 1.11 percent from Mr. Hevert's 0.45 percent.

(4) I anticipate that the 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 9.0 PERCENT ROE AND MR. HEVERT'S 10.1 PERCENT ROE. WHAT ACCOUNTS FOR THIS DIFFERENCE?

A. My 8.5 to 9.0 percent ROE is based upon the application of the standard DCF model to proxy electric (and combination gas/electric) utilities. Although Mr. Hevert conducts cost of equity studies, including the use of the DCF model, his 10.1 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	8.38%*	6	Table 1a
DCF – Multi Stage	9.47*	12	Table 1a
CAPM (excl. ECAPM)	10.13	8	Table 1b
Equity Risk Premium	10.37	2	Table 1b
Average	**9.48%**	--	

*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 8.38 to 10.37 percent, or an average of 9.48 percent (assigning equal weights to the four methods), based on his cost of equity summary table in his testimony. (Note this excludes his "ECAPM" as this is a method that Mr. Hevert did not even use in the last Narragansett case.) Moreover, his constant growth DCF study results – the model often relied upon by this and other regulatory commissions – is 8.38 percent. This result is slightly below my ROE recommendation range and is <u>lower</u> than the currently authorized 9.5 percent set in the 2012 case. Thus, Mr. Hevert's inflated 10.1 percent recommendation is not supported by his own study results, particularly his constant growth DCF studies.

Q. BASED ON HIS STUDIES, WOULD 9.48 PERCENT BE A REASONABLE ROE AWARD IN THIS CASE?

A. While it would be more reasonable than his 10.1 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 CAPM calculations are based on inflated estimates of the overall stock market risk premium, estimates that are simply unreasonably high and could not plausibly reflect investor long-term estimates of returns.

- The most serious error pertains to Mr. Hevert's multi-stage DCF studies (9.47 percent), which assume a long-term growth rate of the U.S. economy of 5.36 percent. This is overly optimistic relative to prevailing expectations of virtually all credible forecasters. Correcting this one flawed parameter would reduce his multi-stage DCF estimate to roughly 9.0 percent. In addition, some of his DCF return calculations assume unrealistically rapid growth over the next 15 years in utility share prices, rapid growth that is unsupported by any objective evidence.

- 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 9.0 percent for Narragansett.

Q. WHAT COST OF EQUITY RESULTS DID YOU OBTAIN?

A. Using market data covering the six months ending January 2018, I obtained the following:

TABLE 2.
Mr. Kahal's Cost of Equity Estimates

Study	Range	Midpoint	Source
Electric/Gas DCF	8.2 – 8.7%	8.5%	Schedule MIK-4
CAPM	6.6 - 9.5%	8.1%	Schedule MIK-5

My DCF estimates, which are the basis of my ROE recommendation for Narragansett, are in the range of 8.2 to 8.7 percent, similar to what Mr. Hevert obtained. My point value recommendation at this time of 9.0 percent (or 8.5 percent after recognizing likely PIM earnings) gives some recognition to the recent instability in capital markets and apparently rising cost of capital which seems evident since January 2018 (the end point of my historical market data). I discuss capital market conditions and trends further below in Section II.C. of my testimony. My ROE recommendation also recognizes that Narragansett is a very low risk "wires and pipes" distribution utility and that Rhode Island ratemaking has provided a range of risk reducing ratemaking mechanisms. In addition, the Company has a very strong balance sheet and favorable credit profile. For all of these reasons, I believe that a reduction to the currently authorized ROE of 9.5 percent to 9.0 percent in this case would be reasonable. Nonetheless, I shall continue to carefully monitor financial market conditions during the remainder of this case to determine whether a modification to my current ROE recommendation is warranted.

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 2017, on page 1 of Schedule MIK-2. Pages 2, 3, 4, 5, 6 and 7 of that schedule show monthly data for January 2007 through February 2018. The indicators provided include the annualized inflation rate (as measured by the Consumer Price Index), ten-year Treasury note 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 7 to 8 percent, with 10-year Treasury yields of 4 to 5 percent. By 2016, Single A utility bond yields had fallen to an average of 3.9 percent, with ten-year Treasury yields declining to an average of 1.8 percent. During most of 2017, yields on long-term debt remained reasonably close to those historic lows.

As shown on Schedule MIK-2, for the time period 2009 through 2015, 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) were 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. Note that by law, the Fed must implement a policy referred to as the "dual mandate", simultaneously promoting price stability and maximum employment for the U.S. economy.

The Fed has also sought to exert downward pressure on long-term interest rates through its policy of "quantitative easing," although that program effectively ended in 2015, with Fed announcing the phasing out of that program in October 2014. This policy involved the purchase by the Fed of long-term financial assets in the form of Treasury bonds and federal agency long-term debt (i.e., mortgage bonds). As Mr. Hevert correctly observes, this policy has resulted in an increase over a period of several years in the Fed's balance sheet from less than $1 trillion to over $4 trillion at the conclusion of that program and as of today. Quantitative easing was intended to support economic recovery by lowering the cost of capital, increasing the value of financial assets and encouraging credit expansion.

Q. ARE THERE FORCES THAT HAVE CONTRIBUTED TO LOW INTEREST RATES OTHER THAN FED POLICY?

A. Yes. While the decline in short-term rates to near zero in recent years is largely attributable to Fed policy decisions, the behavior of long-term rates reflects more fundamental economic forces as well as Fed policy. Factors that have driven down long-term bond interest rates include the past weakness of the U.S. and global macro economy, the inflation outlook and even international events. A weak or only moderately growing economy 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. The Fed has employed a long-term inflation target of 2.0 percent, and inflation generally has been below or close to that target, as have the market's inflationary expectations.

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. HAS THE FED PROVIDED MORE RECENT INFORMATION ON ITS POLICY DIRECTION?

A. Yes, it has. Due to positive progress in strengthening labor markets (the U.S. unemployment rate has been gradually declining to 4.1 percent), improvements in economic growth in the near term, and inflation moving up modestly closer to the 2 percent target, the Fed has moved away from near zero interest rates to a broad policy of monetary "normalization", beginning in late 2015 and continuing to the present day. This consists of a series of increases in short-term interest rates and beginning the unwinding of quantitative easing (i.e., very gradually reducing the Fed's holdings of long-term Treasury and agency debt). This policy shift has been recently affirmed in the Fed's semi-annual February 2018 *Monetary Policy Report* to Congress and its press release following the March 23, 2018 meeting of the Federal Open Market Committee ("FOMC") at which it raised short-term interest rates to a range of 1.5-1.75 percent. Fed and FOMC statements make clear that despite the change to a policy of normalization, monetary policy remains "accommodative" with changes being gradual.

As a result of Fed policy, as well as conditions in U.S. and global capital markets, in 2017 long-term interest rates remained extremely low (though slightly higher than the historic lows of 2016), and the stock market flourished. Utility stocks also performed well in most of 2017 despite the gradual firming of short-term and long-term interest rates in the last half of the year.

Q. HAS THE PATTERN BEEN SIMILAR FOR EQUITY MARKETS IN 2018?

A. While January 2018 was a strong month for the stock market (due to the corporate earnings benefit of the Tax Cut and Jobs Act enacted in December 2017 and a strengthening economy), the past few months as of this writing have seen extreme stock market volatility and further gradual increases in interest rates. Although short-term fluctuations in the stock market are always difficult to interpret, it may be due to a combination of risks of further interest rate increases, rising federal budget deficits (due to both the tax cut bill and Congressional budget decisions) and concerns over international trade policy changes.

Despite this capital market instability, the cost of capital remains quite low by historical standards. In particular, the yield on 30-year Treasury bonds (the benchmark used by both Mr. Hevert and myself) in recent weeks has remained at 3.1 percent, which is only about 0.3 percent above the 2.8 percent average prevailing in the six months ending January 2018. (Please see page 2 of Schedule MIK-5.) The cost of long-term debt for single A rated utilities (such as Narragansett) has also risen slightly but remains close to or slightly above 4.0 percent.

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 but not completely. Following my past practice, I have based my DCF analysis on market data from the six months ending January 2018. Thus, strictly speaking my analysis measures the utility cost of capital during that recent time period. Therefore, it does not measure the changes in the cost of capital since January 2018. As discussed above, markets have been extremely volatile since then, and there is evidence of at least a modest increase in the cost of capital. For example, I calculated the change in utility share prices from my 22-company proxy group from October 31, 2017 (the midpoint of my six month period and close to a high for utility prices) to March 23, 2018. Over that time period, utility share prices have declined on average by about 10 percent – implying an increase in the utility dividend yield by about 0.3 to 0.4 percent. I also calculate a March 31, 2018 dividend yield for my proxy group averaging 3.5 percent, or about 0.3 percent above my six month average. I must caution that this is a very short-term observation, and it is hazardous to assume either that utility share prices will soon recover or that interest rates will return to 2016 or 2017 levels. It is also highly speculative to assume that the cost of capital will rise further as Mr. Hevert posits. I have taken these 2018 to date capital cost trends into account by recommending an ROE award (before PIM earnings) of 9.0 percent, a figure modestly above my DCF range of results and at the upper end of my CAPM results.

I consider the uncertainty and instability in capital markets since January to be an extremely important issue at this time for rate of return determination purposes in this case. Consequently, I intend to revisit this issue at the time of my surrebuttal testimony based on available evidence at that time.

D. Testimony Organization

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. Section III of my testimony explains my proposed changes 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 DCF study and the CAPM calculations. It also summarizes my ROE recommendation including the effect of potential PIM earnings on that recommendation. 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 June 30, 2017, and he makes four 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 $0.97 million), which has the effect of slightly increasing the equity balance. Third, the Company assumes a $250 million long-term debt issue to take place later this year at a cost of 3.99 percent. For capital structure purposes, the Company assumes that $100 million of that $250 million is to be used to reduce short-term debt. Hence, Mr. Hevert increases long-term debt by $150 million and reduces short-term debt by the same $100 million, resulting in net increase in total debt of $150 million. Fourth, he reduces common equity by $50 million which can be interpreted as a dividend payment of that amount to the parent. These four adjustments to the actual year-end capital structure result in a proposed ratemaking capital structure of 51.0 percent common equity, 0.11 preferred stock, 0.45 percent short-term debt and 48.5 percent long-term debt. (Source: Schedule RBH-12)

Mr. Hevert's filed testimony also includes one other minor adjustment to capital structure, a deduction from the debt balance of $2.2 million of unamortized debt discount. However, the response to Division 4 -3 withdraws that adjustment as being improper. That correction has no material effect on the Company's recommended capital structure or cost of capital.

Q. DO YOU AGREE THAT THE COMPANY'S PLAN TO ISSUE TO ISSUE A $250 MILLION LONG-TERM DEBT ISSUE SHOULD BE INCLUDED IN CAPITAL STRUCTURE?

A. Yes, it should although the timing and cost rate of this planned new debt is uncertain. The Company should update the record on the status of that new issue as part of its rebuttal filing or in a supplemental filing prior to the close of the record in this case. The inclusion of this new debt issue is appropriate so that the ratemaking capital structure properly reflects the Company's long-term capital structure targets. (Response to Division 4 -1)

Q. DOES YOUR RECOMMENDATION ON CAPITAL STRUCTURE TAKE INTO ACCOUNT THE COMPANY'S PLAN TO USE THE NEW LONG-TERM DEBT PROCEEDS TO EXTINGUISH MOST OF ITS SHORT-TERM DEBT BALANCE?

A. Yes, but I have done so in a different manner than the Company. At the outset, it is reasonable to assume that new long-term debt will be used to pay down most of the short-term debt as that is one of the asserted purposes of issuing new long-term debt, as stated in the Company's debt issuance application in Division Docket No. D-17-36. However, this reduces the debt balance down to a very low level of about $10 million. Such a low balance could occur for a short period of time after the debt issue, but this figure is unrealistic on a longer-term ongoing basis. For example, in response to Division 4 – 4, the Company indicates that for the three year period January 2015 through December 2017 short-term debt balances exceeded $100 million in every month except for one, sometimes exceeding $200 million. Moreover, the response to Division 4 – 7 indicates that a $14.5 million First Mortgage Bond matures in March 2018. I therefore assume for capital structure purposes that

$14.5 million of the new issue is used to redeem the maturing First Mortgage Bond and $85.5 million is used to extinguish short-term debt. This does not change the total debt balance or ratio as compared to the Company's position, but it does reduce long-term debt by $14.5 million and increases short-term debt by that same amount (to balance of $25 million).

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

A. Yes. I can accept the Company's (provisional) adjustment for new long-term debt (and corresponding reduction in short-term debt, as modified above), the $50 million dividend payment and its removal of $725 million from equity of goodwill. However, the Company also has included an adjustment of remove $0.97 million of Accumulated Other Comprehensive Income ("OCI") from equity. Since the OCI is asserted to be a negative balance, this has the effect of slightly increasing the equity ratio. I do not think that exclusion is warranted and I have excluded it. This adjustment of less than $1 million has a minimal effect on the ratemaking capital structure.

Q. WHY DO YOU OBJECT TO THE EXCLUSION OF OCI FROM CAPITAL STRUCTURE?

A. In making the OCI adjustment, Mr. Hevert is claiming that the common equity balance is slightly 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 its capital structure target, it can certainly do so. In this particular case, I recognize my reversal of the Company's adjustment is small and does not materially affect the ratemaking capital structure.

Q. WITH THESE ADJUSTMENTS, WHAT ARE YOUR CAPITAL STRUCTURE RESULTS?

A. I show my recommended capital structure calculation on page 1 of Schedule MIK-1. I start with the Company's proposed capital structure as shown on Mr. Hevert's Schedule RBH – 12 (as corrected in response to Division 4 – 3). I then make the following adjustments: (1) reduce long-term debt by $14.5 million to reflect the maturing debt; (2) increase short-term debt by $14.5 million; and (3) reverse the OCI exclusion by $0.97 million thereby increasing the equity balance by that amount. This results in a common equity ratio of 50.91 percent common equity, 0.11 percent preferred stock, 1.11 percent short-term debt and 47.90 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 my DCF proxy group utility companies that I employ on Schedule MIK-3. The equity ratios for this 22 company group average 48 percent with about half of the equity ratios over 50 percent. Please note that the equity ratios for the proxy group companies 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 51 percent equity ratio is clearly within the range of industry practice, although slightly above the industry (proxy group) average.

Q. IS THE RECOMMENDED CAPITAL STRUCTURE CONSISTENT WITH THE CAPITAL STRUCTURE APPROVED IN THE COMPANY'S LAST CASE?

A. Yes. It appears that the Company is taking the same general approach to capital structure in this case as in the 2012 rate case. In that case, a 49 percent equity ratio was approved as part of the settlement, which reflected a large new long-term debt issuance used in large part to reduce short-term debt. The Company in this case has increased its equity ratio to 51 percent, which is more expensive than the capital structure approved in the last case but within an acceptable range. The Company's relatively strong balance sheet and expensive capital structure should be taken into account in considering the appropriate return on equity and is a reason for awarding in this case a lower return on equity than the 9.5 percent in the last case.

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-13, Narragansett has $1,097.5 million of long-term debt (inclusive of the planned debt issuance) with an overall embedded cost rate of 4.84 percent. The long-term debt falls into two categories, $1,050 million of senior notes at a cost rate of 4.69 percent and $47.5 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 8.09 percent.

Mr. Hevert sets the electric service cost of debt at the 4.69 percent cost rate based solely on the senior notes. His gas service cost of debt is a blend or weighted average of the 4.69 percent senior note cost rate and the 8.09 percent FMB cost rate, or 5.18 percent. The key to this weighted average calculation is his assumption of how much of the total $1,050 million of long-term debt is gas related. Mr. Hevert assumes 30 percent is gas related and 70 percent is electric related.

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

A. Not entirely. I have one modification as alluded to earlier. The Company includes in its cost of debt calculation, a First Mortgage Bond of $14.5 million due to mature in March 2018. I believe that it is appropriate to exclude the cost of this debt issue going forward. As this debt issue has a cost rate of 6.87 percent, its exclusion would reduce the embedded cost of debt. However, since the legacy First Mortgage Bonds are assigned entirely to gas operations, this has no effect on the 4.69 percent electric operations cost of debt. It does, however, reduce the gas operations embedded cost of debt slightly from 5.18 percent to 5.10 percent.

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 $250 million and the 3.99 percent cost rate only as a provisional estimate. This cost rate apparently is based on the assumption that Narragansett issues 30-year debt. These provisional values should be revisited later in this case both for capital structure and cost of debt purposes if and when further information becomes available.

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 58-71 of his testimony. He argues that Narragansett is riskier (or should be perceived as no less risky) than his proxy companies (which are mostly 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. This would make Narragansett riskier than average.
- Despite the fact that Narragansett has been provided several very favorable regulatory features, such as revenue decoupling, cost trackers, and a multiyear rate plan with earnings sharing) this should be disregarded for rate of return setting purposes.
- Narragansett has a large capital spending program going forward, and this warrants highly supportive regulatory treatment from the Commission.

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 as compared to his proxy company cost of equity results. Specifically he identifies a proxy group cost of equity range of 10.0 to 10.75 percent and a Narragansett ROE award of 10.1 percent, or about 0.28 percent below the midpoint.

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. The response to Division 4 – 8 indicates that Narragansett’s credit ratings have been quite stable, remaining the same over the past five years.

S&P regards Narragansett as having an “excellent” business risk position “reflecting its low-risk distribution operations”. (S&P report of March 22, 2013.)

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 the parent's "relatively high financial leverage". The overall positive assessment is that Narragansett and the other National Grid utility subsidiaries benefit from "the large and diversified parent company that is focused on low-risk electricity and gas transmission and distribution operations". (Id.)

Moody's has a similarly favorable view of Narragansett's investment risk. Moody's August 29, 2017 report references "the stable and predictable cash flows, and the generally supportive regulatory environment in Rhode Island". However, Moody's also states that Narragansett's ratings are constrained by high levels of parent debt and weak ring-fencing provisions.

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

A. No, he has not. His discussion risk factors covers the three topics listed above. He argues that only one of these – Narragansett's asserted small size -- is adverse for Narragansett relative to the proxy group. He either implicitly or explicitly argues that capital requirements and ratemaking features (trackers and revenue decoupling) are similar for Narragansett and the proxy group. As discussed below, his argument regarding size as a risk factor is flawed and unpersuasive.

Q. MR. HEVERT CLAIMS THAT NARRAGANSETT'S ALLEGEDLY SMALL SIZE INCREASES ITS RISK RELATIVE TO THE PROXY GROUP. DO YOU AGREE?

A. No, and frankly his analysis is both incorrect and unsupported. The bulk of the evidence that he cites to demonstrate that size is an equity risk factor pertains primarily to non regulated companies. He has no credible evidence that size is a significant risk factor for regulated utilities.

More to the point, it is absurd to consider Narragansett to be a small company. It is a wholly-owned subsidiary of National Grid USA, which has 6.6 million utility customers (response to Division 4 – 13) and has total book capitalization totaling about $30 billion. National Grid is larger than, not smaller than, the proxy group average company. The point here is that Narragansett is a business unit of National Grid and contributes to the size, business and geographic diversification of National Grid, factors that Mr. Hevert argues contribute to lowering business risk. The small size argument therefore has no merit for Narragansett.

Q. MR. HEVERT SEEMS TO ACKNOWLEDGE THAT NARRAGANSETT HAS FAVORABLE REGULATORY FEATURES IN THE FORM OF TRACKER COST RECOVERY MECHANISMS AND REVENUE DECOUPLING, BUT HE ARGUES THAT THIS SHOULD NOT BE INCORPORATED INTO THE ROE DETERMINATION. DO YOU AGREE WITH HIS ANALYSIS?

A. No. Mr. Hevert does acknowledge that Narragansett's regulation provides favorable features such as cost trackers and revenue decoupling, but he argues this should not be factored into the ROE award determination. In rejecting such an adjustment, he is really making two separate arguments regarding this risk topic. His first argument, which I find implausible, is that these favorable ratemaking mechanisms do not materially reduce a utility's business risk and therefore cost of capital, as compared to "traditional ratemaking" through base rate cases. Such an argument is implausible because the purpose of these mechanisms is to stabilize utility earnings and cash flow, reduce regulatory lag and provide greater cost recovery certainty. I note that the credit rating reports for the Company find these mechanisms to be credit supportive and reduce risk. If these mechanisms do not improve a utility's business risk profile, then it would seem unlikely that utilities would expend so much effort to obtain regulatory or legislative approval for them. That said, I do understand his argument that it is very challenging to objectively quantify the cost of capital savings from these mechanisms, and I have not attempted to do so, nor have most regulators.

Mr. Hevert's second argument is that there is no reason to make a risk adjustment for these favorable ratemaking mechanisms in this case for Narragansett because his proxy companies to varying degrees also have such mechanisms. In other words, even if these mechanisms reduce the Narragansett business risk and cost of capital, he believes that his DCF studies using his proxy companies already fully account for any cost of capital savings. This implies that this issue then can be ignored for ROE purposes.

The problem with Mr. Hevert's argument and evidence on this topic is that he is not able to show that the proxy companies, on average, have these favorable ratemaking mechanisms to the same extent as Narragansett. He is merely able to show that all proxy companies have one or more tracker mechanism or decoupling in at least one jurisdiction that regulates each company. For example, a number of proxy companies have revenue decoupling, but certainly not all. For that reason, it is reasonable to argue that, on average, Narragansett is risk advantaged due to these favorable regulatory features (or at a minimum Mr. Hevert has not shown this not to be the case). While like Mr. Hevert, I have not attempted to quantify a specific risk adjustment, I believe that it is appropriate for the Commission to make note of the risk reducing cost recovery features in setting Narragansett's ROE within a reasonable range.

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 and its capital investment in utility plant is vitally important, 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 and 2012 long-term debt issuances and its expectation of issuing $250 million of 30-year debt at a favorable cost rate of 3.99 percent. The credit rating agencies assign the single-A rating to Narragansett with full knowledge of the Company's capital spending outlook and Rhode Island regulatory practices which they characterize as supportive.

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. Mr. Hevert, while raising the capital investment issue, provides no basis for claiming that this issue in any way indicates that Narragansett is disadvantaged relative to the proxy utility companies.

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

A. At the outset, the vast majority of Mr. Hevert's proxy group companies are vertically-integrated meaning that they own and operate generation resources, whereas Narragansett does not. The Division asked Mr. Hevert for risk comparisons of vertically-integrated electrics, unregulated generation and electric/gas utility distribution service in Division 4 - 15. In his response Mr. Hevert stressed that each situation is unique and must be separately analyzed. Nonetheless, he did offer a certain broad generation, noting that:

> Holding all else equal, an electric utility that owns generation may have more risk than a distribution-only utility. The nature of any such risk differential, however, varies on a case-by-case basis.

While I find Mr. Hevert's response to be limited and qualified, I believe he confirms the consensus view among analysts that as a general matter regulated generation supply is typically perceived 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 mostly vertically-integrated electrics (and combination electric and gas) is riskier than Narragansett due to the ownership and operation of generation assets. This risk advantage for Narragansett is material, and the Commission should take it into account in its final determination of the appropriate ROE award in this case.

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 ROE bonus (aside from PIM issues) 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 specific 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 (as discussed in my Section III) 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 V 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 a proxy group of utility companies. I discuss this proxy group later in this section. However, for reasons discussed in my testimony, I emphasize the DCF model results (as applied to the utility proxy group) 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 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. That is, individual company DCF calculations should not be relied upon to draw conclusions, and almost all rate of return analysts employ proxy groups.

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 (due to unrealistic model inputs) 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 would not 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 about 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 those selected by Mr. Hevert. He has selected 24 utility companies that are mostly electric but many of which also have gas distribution operations. Of these 24, I would regard 21 as being vertically-integrated (providing their own generation supply on a regulated basis) and three companies that I would regard as being primarily delivery service companies similar to Narragansett (i.e, Centerpoint Energy, Consolidated Edison and Eversource Energy). 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 non-regulated activity. I do not object to his screening criteria. Ideally, it would be desirable to also employ a proxy group of predominantly delivery service utilities, but due to merger activity in recent years, it is no longer practical to do so.

I have utilized all of Mr. Hevert's 24 proxy companies with two exceptions. I have excluded Duke Energy and Dominion Energy. Subsequent to Mr. Hevert's testimony preparation, Dominion became involved in a major merger and therefore must be removed based on Mr. Hevert's own criteria. Duke did pass Mr. Hevert's screen, but the Company has substantial non-regulated generation which it may be attempting to divest. This is not intended to be a criticism of Mr. Hevert's proxy group (which under the circumstances is reasonable), and I do not believe these two exclusions cause a significant change to my DCF results. Consequently, for DCF purposes, I am employing a proxy group of 22 companies nearly identical to that of

Mr. Hevert. This has the advantage of removing the issue of proxy group selection as an issue in this case.

Q. PLEASE IDENTIFY YOUR PROXY COMPANIES.

A. I show a listing of the 22 proxy companies used in my DCF study on page 1 of Schedule MIK-3 along with several risk-type indicators for each company. 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>Conducting the Proxy Group 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 public data sources, I compiled the month-ending dividend yields for the six months ending January 2018, a relatively recent period of market data available to me as of this writing. This time period covers primarily the last half of calendar 2017 and the beginning month of 2018. During the last half of 2017, the overall stock market experienced significant gains, but utility stocks were fairly stable. After moving higher in January 2018, the broader stock market has declined somewhat from its earlier highs and experienced substantial volatility in response to market and economic developments discussed in

Section II.C. of my testimony. Utility stocks have declined in price significantly since the beginning of 2018.

I show these dividend yield data on page 2 of Schedule MIK-4 for each month and each proxy company, August 2017 through January 2018. Over the 2017 portion of this six-month period the proxy group average dividend yields were relatively stable, ranging from a low of 3.00 percent in November to a high of 3.17 percent in December. However, the average dividend yield moved up to 3.43 percent in January 2018. Over the six-month period, the proxy group companies' dividend yield averaged 3.14 percent.

For DCF purposes and at this time, I am using a proxy group dividend yield of 3.14 percent as the starting point in my analysis.

Q. IS 3.14 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 3.2 percent. This is based on assuming that half of a year growth is 2.75 percent (i.e., a full year growth is 5.5 percent). The adjusted yield calculation is 3.14% x 1.0275 = 3.23%.

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 (slightly earlier) time frame for his market prices (mid to late 2017 ending October 2017), 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. 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, Zacks, 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 2014-2016 compared to the annual average for the forecast period of 2020-2022.

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 5.4 percent for CNNfn, 4.9 percent for YahooFinance, 5.0 percent for Zacks, 5.2 percent for Reuters and 5.3 percent for Value Line. Thus, the range of growth rates among the five sources is 4.9 to 5.4 percent. The average of these five sources is 5.2 percent, and I have used these results (along with other evidence) in obtaining a reasonable expected growth range for the group of 5.0 to 5.5 percent.

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 annualized growth that investors may consider 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 22 proxy companies, dividend growth averages 5.4 percent, book value growth averages 4.0 percent, and earnings retention growth averages 3.9 percent.

Some analysts and regulators favor the use of earnings retention growth (often referred to as "sustainable growth"), which Value Line indicates to be 3.9 percent (for the proxy companies). This method has been relied upon in the past by this Commission. I note that Mr. Hevert also makes some use of this method of estimating growth as shown on his Exhibit RBH – 3. 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 2020-2022) in shares outstanding, along with the current ("recent") stock price premium over book value. For these 22 companies, the external growth rate calculated in this manner averages about 0.6 percent. The sum of "internal" or earnings retention growth factor (i.e., 3.9 percent) and the "external" growth rate factor (i.e., 0.6 percent) is 4.5 percent. Mr. Hevert obtains a very similar growth rate figure of 4.3 percent as shown on his Exhibit RBH-3 for his 24 companies.

Given this estimate of 4.5 percent for the sustainable growth rate and 5.4 percent for published securities analyst earnings projections, a reasonable and conservatively high DCF growth rate range for this proxy group is approximately 5.5 to 5.0 percent. This range emphasizes the securities analyst growth rate measure since Value Line (the source of the earnings retention growth rate) has the disadvantage of being a single source of investor information.

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 January 2018 is 3.2 percent for this group. Available evidence would support a long-run growth rate in the range of approximately 5.0 to 5.5 percent, as explained above. Summing the adjusted yield and growth rate range produces a total return range of 8.2 to 8.7 percent, and a midpoint result of 8.5 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. <u>ROE Recommendation and PIM</u>

Q. WHAT IS THE BASIS OF YOUR ROE RECOMMENDATION?

A. My ROE recommendation in this case is guided by my DCF results (which has been this Commission's preferred cost of equity methodology), a consideration of changing conditions and recent trends in U.S. capital markets and Narragansett's risk profile. As discussed above, my DCF study produced a range of 8.2 to 8.7 percent with a midpoint of 8.5 percent for a recent historical time period ending in January 2018. I note that my DCF results are very similar to Mr. Hevert's DCF study results (i.e., his constant growth model) based on his mid to late 2017 time frame. Since that recent time period, short-term and long-term interest rates have moved up, in the case of 30-year Treasury yields by about 0.3 percent. Moreover, utility stocks have experienced significant declines in price from their fall 2017 highs to late March 2018, implying increased dividend yields and therefore a likely higher cost of equity. As a result of these very recent capital cost trends since the beginning of 2018, I believe that a cost of equity finding for Narragansett of 9.0 percent is more reasonable at this time than either my 8.7 percent upper end or 8.5 percent midpoint. Given current market conditions, I would regard the 8.5 percent figure as being a reasonable lower bound ROE award. It is important that such capital cost conditions and trends be revisited as part of the rebuttal/surrebuttal part of this case.

Q. SHOULD THE COMMISSION CONSIDER NARRAGANSETT'S RISK ATTRIBUTES WHEN CONSIDERING THE APPROPRIATE ROE AWARD IN THIS CASE?

Yes. Both my and Mr. Hevert's standard DCF results are derived from a broad industry proxy group that could differ in risk from Narragansett. In my opinion, Narragansett's risk profile is quite favorable relative to the industry proxy group, and the Commission should consider this when evaluating the range of evidence even if (as Mr. Hevert argues) it is impractical to quantify a specific risk adjustment. Narragansett's favorable risk profile is the result of a combination of important factors including its strong balance sheet (including the 51 percent equity ratio sought in this case), its favorable ratemaking/cost recovery mechanisms approved by this Commission and its status as a "wires and pipes" delivery service utility with virtually no generation supply risk. The vast majority of the DCF proxy companies incur significant generation supply risk. For all of these reasons, it is reasonable to reduce Narragansett's authorized ROE in this case.

Q. HOW SHOULD THE DIVISION'S PIM RECOMMENDATION IN THIS CASE AFFECT THE COMMISSION'S ROE AWARD?

A. The Division in this case is recommending a PIM program that would provide Narragansett with an additional earnings opportunity for meeting certain performance goals or metrics over the next three years. This topic has also been addressed by the Company in this docket and in Docket No. 4780. The Company argues that these performance metrics are for Rhode Island policy objectives outside of its traditional or "core" public utility responsibility of providing reliable electric and gas service at lowest reasonable cost. To the Company, this implies that PIM is unrelated to the normal task of setting the authorized rate of return on equity on "core" utility rate base at a reasonable estimate of the cost of equity. In fact, Mr. Hevert does not address PIM earnings potential at all in his testimony. While I understand the Company's position, I do not fully agree that PIM earnings should be ignored for rate of return setting purposes.

My understanding is that the Division is proposing additional PIM earnings opportunity that it should be realistically able to achieve on its electric operations though the Division is proposing no such program at this time on gas operations. Moreover, the PIM earnings opportunity is asymmetric, meaning that it provides only awards and not penalties. There is only an upside from PIM, and this is the Company's position as well. Consequently, for purposes of this case, I recommend that if the Commission approves such an asymmetric PIM program, it should award Narragansett an electric operations ROE 8.5 percent which is at the lower end of my recommended 8.5 to 9.0 percent reasonable cost of equity range at this time. This would properly and conservatively recognize a reasonable PIM earnings potential and avoid PIM being an unwarranted earnings windfall. I would further note that in my opinion, 8.5 percent, while lower than 9.0 percent, is within the reasonable range of cost of equity evidence at this time, and for that reason should be considered to be a fair rate of return regardless of PIM earnings. The gas operations ROE should not be altered for PIM and should therefore be set at this time at 9.0 percent.

In addition to my recommendation to use the lower end of the cost of equity/ROE range for electric operations due to PIM (a modest 0.5 percent difference), I believe that a further consumer protection is needed in the event that a PIM program ends up being unreasonably generous to the utility. Narragansett has been operating under an earnings sharing plan which provides customers with rate savings in the event that the Company's earnings exceed an ROE threshold. I recommend that PIM earnings be included in that mechanism in a limited way for electric operations. Specifically, I recommend that PIM earnings be excluded from any earnings sharing calculation and obligation for Company (electric operations) earnings up to earnings of 9.5 percent ROE (i.e., 100 basis points over the ROE award which under my recommendation is 8.5 percent). However, if the achieved ROE exceeds 9.5 percent, then PIM earnings should be included in the earnings calculation and the earnings sharing mechanism. This is intended as a "guard rail" to ensure the PIM program does not unduly enrich the Company at the expense of customers. At the same time, it leaves the Company with substantial incentive to achieve PIM performance metrics as it may keep all PIM earnings up to the 9.5 percent ROE on total electric operations and even a portion above an ROE of 9.5 percent per the earnings sharing formula. I believe this guard rail is needed in part due to a lack of experience in Rhode Island with a large scale PIM program and therefore the need to proceed cautiously with respect to earnings awards.

Q. PLEASE EXPLAIN FURTHER WHY YOU BELIEVE EXCESS EARNINGS PROTECTIONS ARE NEEDED TO ACCOMPANYING A PIM PROGRAM.

A. I understand the Company's argument that the PIM program is new and outside of the traditional core utility functions of Narragansett. I also understand the argument that a PIM program to be effective needs financial rewards to incent performance. However, the Company and the Division both are supporting asymmetric programs that can only increase earnings and not reduce it. This creates a dilemma. Even if the PIM program is considered "non-core" to utility operations (which is debatable), it is important to note that Narragansett remains a monopoly provider in Rhode Island of utility service, and the PIM program would also be in the context of monopoly service. The PIM program is specifically designed to provide an opportunity (though not a guarantee) of an increase in profits for that monopoly utility over and above its standard profit opportunity on utility service. It has long been understood that a fundamental purpose of regulation of a "natural monopoly" is to prevent the exercise of monopoly power and the extraction of a monopoly level of profits by the utility from captive customers. For this reason, along with the lack of experience with an ambitious PIM program, it is important that customer protections on earned ROE accompany this asymmetric program. The 0.5 percent ROE difference (although remaining in the reasonable range for ROE) and partial inclusion in earnings sharing provides a reasonable balance of protection of customers from unreasonable monopoly profits while preserving performance incentives and fairness to the Company.

D. The CAPM Analysis

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 in applying the CAPM, however, is in the measurement of the expected stock market rate of 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 of 1, for the company-by-company betas.) In last six months, long-term (i.e., 30-year) Treasury yields have averaged approximately 2.8 percent, although it recently has risen to about 3.1 percent. I therefore use 3.0 percent as a representative risk-free rate for the very recent historical period. The currently-published Value Line betas for my utility proxy group companies average about 0.72. 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 0.72 and an equity risk premium of 5 percent.

$$K_e = 3.0\% + 0.72\ (5.0\%) = 6.6\%$$

The upper end estimate uses a risk-free rate of 3.0 percent, a proxy group beta of 0.72 and an equity risk premium of 8.0 percent.

$$K_e = 3.0\% + 0.72\ (8.0\%) = 8.8\%$$

Thus, with these inputs the CAPM provides a cost of equity range of 6.6 to 8.8 percent, with a midpoint of 7.7 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 in part the difficulty in identifying a reliable estimate of the market risk premium. Moreover, in my opinion, the DCF model is a far more appropriate method of measuring the cost of equity for utility companies.

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

A. On Schedule MIK-5, 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:

$$K_e = 3.0\% + 0.72\ (9.0\%) = 9.5\%$$

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 9.5 percent. This high end sensitivity estimate is somewhat above my DCF results but still well below Mr. Hevert’s recommended range of 10.0 to 10.75 percent.

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

A. Mr. Hevert appears to employ a market risk premium range of 11.1 to 11.5 percent, averaging 11.3 percent, in his CAPM calculations. With a risk-free rate of 3 percent, this risk premium range would mean that investors are expecting a long-term average rate of return on stocks of about 14 percent (or more), an implausibly high rate of return expectation. (See Mr. Hevert's Exhibit RBH-7.) His equity market risk premium assumption figure is more than 3 full percentages points above what I would consider to be a reasonable upper bound. This market risk premium range, when used in conjunction with the Value Line and Bloomberg beta values for his proxy group and risk free Treasury yields of 2.8 to 3.3 percent, produce CAPM estimates that average about 10.1 percent, which is well above my CAPM results. Again, these very high utility CAPM cost of equity estimates are merely an artifact of assuming an unrealistically high stock market rate of return.

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 on my Table 1, his study results average to 9.48 percent if each of the four methods is assigned equal weight.[1] The method providing the lowest cost of equity method is the constant growth DCF (8.38 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 10.1 percent to be a reasonable ROE point value for Narragansett. The 10.75 percent is a figure within his identified range of 10.0 to 10.75 percent, but the source of this range is also unclear. In particular, the lower bound of 10.0 percent is a full 170 basis points (1.7 percentage points) higher than the average of his constant growth DCF study results. His 10.0 percent lower bound cost of equity is also above the average cost of equity for his four methodologies as summarized on his Tables 1a and 1b. Examining Mr. Hevert's results more objectively (before considering any

[1] The average does not include the ECAPM, a method not used by Mr. Hevert in the last Narragansett case. With the ECAPM results, the CAPM/ECAPM average increases from 10.06 percent to 10.60 percent. The average of the four methods increases from 9.48 percent to about 9.6 percent, again assuming that each of the four methodologies is accorded equal weight. This section demonstrates that the ECAPM is not a proper method for utilities.

corrections), his four methods would appear to support a range of about 8.4 to 10.1 percent, as I show on my Table I in Section II of my testimony.

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 seems to imply that Narragansett is either similar in investment risk to his proxy companies or even riskier (e.g., his improper "size" argument). This is not correct. Narragansett is unquestionably less risky, on average, than his proxy group of electric (and combination electric/gas) companies which are mostly vertically-integrated electric utilities and therefore are exposed to the risks of generation ownership and operation. My testimony provides other reasons for viewing Narragansett's business and investment risk profile as being less risky than that of the proxy group. For example, even if one accepts Mr. Hevert's proxy group cost of equity results which average about 9.5 or 9.6 percent, the fair cost of equity and fair ROE for Narragansett would be lower than that. .

B. <u>The Multi-Stage DCF Study</u>

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. Mr. Hevert, however, has not shown this to be the case for his proxy group, and thus the need for this model has not been demonstrated.

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 analyst 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 own 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.

At the outset, it is useful to examine the ROE results from this model and compare them to those of the standard constant growth DCF. The later produces a cost of equity estimate of 8.38 percent (using his mean growth rates), whereas the multi-stage model produces a drastically higher average estimate of 9.47 percent. This cost of equity divergence is puzzling since Mr. Hevert is using identical current share prices, current dividends, proxy group and (in part) growth rate data in the two models. As the two models are both based on the same DCF theory and very similar data inputs, they should produce similar results. A closer inspection of his summary Table 1a provides a clue to this puzzle. He uses two "versions" of the multi-state model. His "Gordon" version produces an estimate (on average) of 8.75 percent – a result in the same ballpark as his and my standard DCF. However, his "Terminal

P/E" version produces an average cost of equity of 10.17 percent, which is about 140 basis points above the "Gordon" estimate and about 180 basis points (nearly two full percentage points) above the traditional DCF estimate.

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 what he used in 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 5.36 percent. He bases this assumed figure on historic real growth in the U.S. economy since 1929 (3.22 percent) and his assumed long-term outlook for inflation (2.07 percent). Mr. Hevert's long-term inflation assumption is probably not unreasonable as a reflection of investor expectations, but his 3.22 percent real GDP long-term growth rate is completely unsupported and optimistic as an investor expectation. Based on my review of authoritative sources, the consensus forecast and investor expectations for long-run nominal GDP growth is at least a full percentage point lower – probably in the range of about 4.0 to 4.5 percent. For example, the long-run nominal GPD forecast published by the Federal Reserve (of Fed governors and bank presidents) is 4.0 percent. "Blue Chip Economic Indicators", as of March 10, 2018 publishes a "consensus" forecast from about 40 major forecasting organizations for nominal GDP growth over the next ten years of 4.2 percent per year. The Federal Energy Regulatory Commission uses a very similar long-term (second stage) nominal U.S. GDP growth rate for its two-stage DCF model of about 4.3 percent. I believe Mr. Hevert's error is in naively (and incorrectly) assuming that future growth in the U.S. economy is expected by investors to mirror the long-term historic trend. Forecasters and investors do not adhere to this simplistic and unrealistic assumption as demonstrated by virtually all published forecasts. Part of the reason is that with an aging population, the growth in the U.S. labor force is expected to slow dramatically in the future as compared to the rapid labor force growth rate over the past century.

The next question is what the effect on his multi-stage model results would be if he corrected this mistake and lowered his growth rate to a more reasonable figure. The Division requested in Division 4 – 18 that Mr. Hevert provide his model result using 4.36 percent in place of 5.36 percent. Mr. Hevert refused to comply with this request, so I am unable to provide that correction, even though Mr. Hevert has provided it in past cases. That said, I believe correcting his clearly overstated 5.36 percent GDP growth rate with a more realistic projection (e.g., 4.36 percent) would lower his DCF estimate by about 0.5 percent or even more. Thus, his average multi-stage DCF result would be about 9 percent – in line with my ROE recommendation.

Q. DO YOU HAVE ANY OTHER CONCERNS WITH HIS MULTI-STAGE DCF ANALYIS?

Yes. Correcting the Mr. Hevert's overstated nominal GDP growth rate still produces a cost of equity estimate using the "Terminal P/E" version unrealistically high – likely above 9.5 percent. I therefore examined that particular estimate to determine the source of the overstated ROE problem. This version of his model requires a forecast of the share prices of all 24 of his proxy utility companies in year 15 of his multi-stage study, i.e., in the year 2032. Mr. Hevert has no direct source from investor service publications or any publication for the year 2032 share prices so he simply adopts his own assumption. Mr. Hevert provides the details of his multi-stage DCF using the "Terminal P/E" method on his Exhibit RBH-4, a very lengthy exhibit. On page 47 of that exhibit, I examined his assumptions regarding how proxy company share prices would grow over 15 years from 2017 to 2032. I calculated the annualize growth rate in share prices embedded in that model for each of his 24 companies. The resulting share price growth rate varied from company-to-company, but it averaged 7.1 percent per year for the 24 utility companies. This is equivalent to assuming that over the next 15 years share prices of utilities would nearly triple in value. This is extremely rapid growth in shareholder value, far more rapid than either the published growth rates for earnings that both he and I have used for DCF purposes or even his very high 5.36 percent growth rate for the U.S. economy. This very rapid growth assumption over 15 years, unsupported by any objective evidence and merely selected by Mr. Hevert, explains why his "Terminal P/E" DCF produces cost of equity values in excess of 10 percent when all other DCF modeling from both Mr. Hevert and me show cost of equity estimates of 9 percent or less. Mr. Hevert's Terminal P/E version multi-stage DCF study should be rejected out of hand as being convoluted, unsupported and completely unrealistic.

C. <u>The CAPM and ECAPM Model</u>

Q. MR. HEVERT PRESENTS BOTH STANDARD CAPM AND ECAPM STUDIES IN HIS TESTIMONY. DID HE PREVIOUSLY USE BOTH METHODS?

A. No, he used the standard CAPM in his testimony in Narragansett's last case, but the ECAPM was not employed in that case. My experience has been that the ECAPM is occasionally used by utility-sponsored rate of return witnesses, but it has not received much acceptance by regulators for setting return on equity. Mr. Hevert does not provide any explanation as to why he now employs the ECAPM when he did not do so in the previous Narragansett rate case. Please note that the traditional CAPM produces a cost of equity estimate of 10.06 percent (averaged over his various calculation scenarios) as compared to a much higher 11.13 using the ECAPM, or about a full one percentage point increase.

Q. WHAT ARE YOUR OBJECTIONS TO MR. HEVERT'S TRADITIONAL CAPM STUDY?

A. As discussed in Section III. D., Mr. Hevert has employed a risk premium derived from a stock market expected rate of return that is outlandishly high, a rate of return on the overall stock market of about 14 percent which produces a risk premium value of 11 percent. This is not merely the rate of return on investment expected to prevail in the short run, such as one or two years, but a long run average. A 14 percent stock market rate of return is simply not believable given that his utility DCF produces a rate of return of about 8.4 percent – a more than 550 basis point difference. This is implausible and fully explains why his CAPM cost of equity estimate is so high and out of line with utility DCF evidence. Had Mr. Hevert utilized a reasonable risk premium estimate (such as a figure in or close to the Brealy, et. al. rather wide range of 5 to 8 percent), his CAPM estimates would be much more consistent with his utility DCF evidence.

Q. SHOULD THE ECAPM EVIDENCE BE CONSIDERED BY THE COMMISSION?

A. No, in my opinion it should not, as it is even more unrealistic than Mr. Hevert's standard CAPM. To begin with, this model uses the same overstated 11 percent risk premium and 14 percent stock market rate of return as in the traditional CAPM. This model then takes things one step further. The asserted purpose of the ECAPM is to "correct" for the fact that over time there is an empirical tendency for individual company stock betas to "regress" or drift toward 1.0. This means that high beta stocks would exhibit betas drifting down and low beta stocks would drift up somewhat. The "correction" involves conducting the CAPM in the normal way but applying a 75 percent weight to the beta times risk premium calculation and a 25 percent weight to a beta = 1.0 times the risk premium. This means that for a high beta stock (e.g., a 1.5 beta), the ECAPM produces a lower cost of equity than the traditional model and a higher cost of equity for low beta stocks. Since utilities are always low beta companies, Mr. Hevert's ECAPM systematically increases the measured cost of equity.

There are several reasons why this is improper in the context of the utility cost of capital. First, neither Mr. Hevert nor I are conducting individual stock CAPM studies. Rather, we are using betas averaged over an entire 22 or 24 company proxy group. This reduces the rationale for using the ECAPM. Second, the betas Mr. Hevert uses (Value Line and Bloomberg) already embody adjustments for the asserted tendency of betas to drift toward 1.0 over time. Mr. Hevert states exactly that at page 54 of his testimony. In other words, for utilities both Value Line and Bloomberg first calculate the beta using observed market betas for each company and they then use a formula to increase those betas. Given the fact that Mr. Hevert already is using adjusted betas, his use of the ECAPM constitutes a double count. In other words, his ECAPM is mathematically equivalent to adjusting the utility beta upwards a second time after Value Line and Bloomberg have already done so a first time. Third, the argument for the ECAPM is the asserted tendency of stock betas to move to a market average of 1.0, implying that observed betas overstate or understate risk. But this is simply not true for utilities which are systematically less risky than the overall stock market due to their unique status as regulated monopolies, a fundamental feature that does not change over time. They are much less risky than non-regulated companies due to business fundamentals, and this is not something that "regresses toward the mean" over time.

While the need for the ECAPM formula to "correct" the alleged bias in the standard CAPM is the subject of academic debate, there is no evidence that I have seen or that Mr. Hevert has presented that the ECAPM "correction" is needed or is appropriate in the unique context of setting the utility ROE. Utility risk and betas simply do not over time "drift" or regress toward the mean market beta of 1.0. Rather, the low risk of utilities compared to the stock market as a whole is a fundamental characteristic that does not and will not change materially over time.

Mr. Hevert's use of the ECAPM is totally improper and should be given no weight by the Commission in its consideration of Narragansett's cost of capital.

D. <u>Mr. Hevert's Equity Risk Premium Model</u>

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 two models are estimated using simple regression from a time series of data extending from 1980 to late 2017. 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 low interest rates as compared to historical average, the model implies that we should expect to see a higher equity risk premium. That is the message from his model. I would note that Mr. Hevert calculates over the full historical time period, the risk premium averages about 4.6 percent. If that historical average were to be combined with the current Treasury yield (about 3.1 percent, this would imply a risk premium-derived cost of equity of just under 8 percent.

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 <u>decisions</u> and only partially on market data.

Q. WHAT RESULTS DID HE OBTAIN USING HIS MODEL?

A. Mr. Hevert selects Treasury bond yields of 2.80, 3.30 and 4.40 percent, and with his model he calculates the risk premium cost of equity of 9.96, 10.02 and 10.33 percent for the three interest rates. Mr. Hevert's testimony largely disregards the use of the 4.40 percent Treasury rate which is out of line with current market conditions. I note that the current 3.1 percent 30-year Treasury rate is the midpoint of his relevant 2.8 to 3.3 percent range.

The curious thing about Mr. Hevert's model is that it seems to explain almost nothing. Note that a Treasury rate of 2.8 percent produces a risk premium cost of equity estimate of 9.96 percent, and a Treasury rate of 3.3 percent (50 basis points higher) produces a nearly identical cost of equity of 10.02 percent – a mere 6 basis point difference. In other words a sizeable 50 basis point increase in interest rates results in a negligible increase in the utility cost of equity. The model and the entire methodology therefore has virtually no explanatory power and suggests that there is very little relationship between long-term interest rates and the utility cost of equity. For this reason alone Mr. Hevert's risk premium method should not be taken seriously.

Q. ARE THERE OTHER PROBLEMS WITH THIS METHODOLOGY?

A. Yes, and 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 in some minor way for 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 to be paid by customers. Absent an accepted supporting explanation, the estimated model may simply be spurious – merely a meaningless 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 (as evidenced by interest rates) 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 very weak 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. 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 expanded to electric power markets, mergers, and various aspects of regulation.

Mr. Kahal has provided expert testimony in more than 400 cases before state and federal regulatory commissions, federal courts, 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 Founding Principal, Vice President, and President
Exeter Associates, Inc.
Columbia, MD

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

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

1972-1977 Research/Teaching Assistant and Instructor (part time)
Department of Economics, University of Maryland (College Park)
Lecturer in Business and Economics
Montgomery College (Rockville and Takoma Park, MD)

Professional Experience

Mr. Kahal has more than thirty-five 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 of the firm. During that time, he supervised multi-million dollar support contracts with the State of Maryland and directed the technical work conducted by both 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.

Publications and Consulting Reports

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

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

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

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

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

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

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

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

"An Econometric Methodology for Forecasting Power Demands," Conducting Need-for-Power Review for Nuclear Power Plants (D.A. Nash, ed.), U.S. Nuclear Regulatory Commission, NUREG-0942, December 1982.

State Regulatory Attitudes Toward Fuel Expense Issues, prepared for the Electric Power Research Institute, July 1983 (with Dale E. Swan).

"Problems in the Use of Econometric Methods in Load Forecasting," Adjusting to Regulatory, Pricing and Marketing Realities (Harry Trebing, ed.), Institute of Public Utilities, Michigan State University, 1983.

Proceedings of the Maryland Conference on Electric Load Forecasting (editor and contributing author), Maryland Power Plant Siting Program, PPES-83-4, October 1983.

"The Impacts of Utility-Sponsored Weatherization Programs: The Case of Maryland Utilities" (with others), in Government and Energy Policy (Richard L. Itteilag, ed.), 1983.

Power Plant Cumulative Environmental Impact Report, contributing author (Paul E. Miller, ed.) Maryland Department of Natural Resources, January 1984.

Projected Electric Power Demands for the Potomac Electric Power Company, three volumes (with Steven L. Estomin), prepared for the Maryland Power Plant Siting Program, March 1984.

"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.

The Financial Impact of Potential Department of Energy Rate Recommendations on the Commonwealth Edison Company, prepared for the U.S. Department of Energy, October 1984.

"Discussion Comments," published in Impact of Deregulation and Market Forces on Public Utilities: The Future of Regulation (Harry Trebing, ed.), Institute of Public Utilities, Michigan State University, 1985.

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.

A Survey and Evaluation of Demand Forecast Methods in the Gas Utility Industry, prepared for the Public Utilities Commission of Ohio, Forecasting Division, November 1985 (with Terence Manuel).

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.

Determination of Retrofit Costs at the Oyster Creek Nuclear Generating Station, March 1988, prepared for Versar, Inc., New Jersey Department of Environmental Protection.

Excess Deferred Taxes and the Telephone Utility Industry, April 1988, prepared on behalf of the National Association of State Utility Consumer Advocates.

Toward a Proposed Federal Policy for Independent Power Producers, comments prepared on behalf of the Indiana Consumer Counselor, FERC Docket EL87-67-000, November 1987.

Review and Discussion of Regulations Governing Bidding Programs, prepared for the Pennsylvania Office of Consumer Advocate, June 1988.

A Review of the Proposed Revisions to the FERC Administrative Rules on Avoided Costs and Related Issues, prepared for the Pennsylvania Office of Consumer Advocate, April 1988.

Review and Comments on the FERC NOPR Concerning Independent Power Producers, prepared for the Pennsylvania Office of Consumer Advocate, June 1988.

The Costs to Maryland Utilities and Ratepayers of an Acid Rain Control Strategy – An Updated Analysis, prepared for the Maryland Power Plant Research Program, October 1987, AD-88-4.

"Comments," in New Regulatory and Management Strategies in a Changing Market Environment (Harry M. Trebing and Patrick C. Mann, editors), Proceedings of the Institute of Public Utilities Eighteenth Annual Conference, 1987.

Electric Power Resource Planning for the Potomac Electric Power Company, prepared for the Maryland Power Plant Research Program, July 1988.

Power Plant Cumulative Environmental Impact Report for Maryland (Thomas E. Magette, ed.), authored two chapters, November 1988, PPRP-CEIR-6.

Resource Planning and Competitive Bidding for Delmarva Power & Light Company, October 1990, prepared for the Maryland Department of Natural Resources (with M. Fullenbaum).

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

An Economic and Need for Power Evaluation of Baltimore Gas & Electric Company's Perryman Plant, May 1991, prepared for the Maryland Department of Natural Resources (with M. Fullenbaum).

The Cost of Equity Capital for the Bell Local Exchange Companies in a New Era of Regulation, October 1991, presented at the Atlantic Economic Society 32nd Conference, Washington, D.C.

A Need for Power Review of Delmarva Power & Light Company's Dorchester Unit 1 Power Plant, March 1993, prepared for the Maryland Department of National Resources (with M. Fullenbaum).

The AES Warrior Run Project: Impact on Western Maryland Economic Activity and Electric Rates, February 1993, prepared for the Maryland Power Plant Research Program (with Peter Hall).

An Economic Perspective on Competition and the Electric Utility Industry, November 1994, prepared for the Electric Consumers' Alliance.

PEPCO's Clean Air Act Compliance Plan: Status Report, prepared for the Maryland Power Plant Research Plan, January 1995 (w/Diane Mountain, Environmental Resources Management, Inc.).

The FERC Open Access Rulemaking: A Review of the Issues, prepared for the Indiana Office of Utility Consumer Counselor and the Pennsylvania Office of Consumer Advocate, June 1995.

A Status Report on Electric Utility Restructuring: Issues for Maryland, prepared for the Maryland Power Plant Research Program, November 1995 (with Daphne Psacharopoulos).

Modeling the Financial Impacts on the Bell Regional Holding Companies from Changes in Access Rates, prepared for MCI Corporation, May 1996.

The CSEF Electric Deregulation Study: Economic Miracle or the Economists' Cold Fusion?, prepared for the Electric Consumers' Alliance, Indianapolis, Indiana, October 1996.

Reducing Rates for Interstate Access Service: Financial Impacts on the Bell Regional Holding Companies, prepared for MCI Corporation, May 1997.

The New Hampshire Retail Competition Pilot Program: A Preliminary Evaluation, July 1997, prepared for the Electric Consumers' Alliance (with Jerome D. Mierzwa).

Electric Restructuring and the Environment: Issue Identification for Maryland, March 1997, prepared for the Maryland Power Plant Research Program (with Environmental Resource Management, Inc.).

An Analysis of Electric Utility Embedded Power Supply Costs, prepared for Power-Gen International Conference, Dallas, Texas, December 1997.

Market Power Outlook for Generation Supply in Louisiana, December 2000, prepared for the Louisiana Public Service Commission (with others).

A Review of Issues Concerning Electric Power Capacity Markets, prepared for the Maryland Power Plant Research Program, December 2001 (with B. Hobbs and J. Inon).
The Economic Feasibility of Air Emissions Controls at the Brandon Shores and Morgantown Coal-fired Power Plants, February 2005 (prepared for the Chesapeake Bay Foundation).

The Economic Feasibility of Power Plant Retirements on the Entergy System, September 2005, with Phil Hayet (prepared for the Louisiana Public Service Commission).

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, Baton Rouge, Louisiana, October 2, 2002 (presentation on Performance-Based Ratemaking and panelist on RTO issues).

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

Expert Testimony
of Matthew I. Kahal

	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

Expert Testimony
of Matthew I. Kahal

	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

Expert Testimony
of Matthew I. Kahal

	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

Expert Testimony
of Matthew I. Kahal

	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

Expert Testimony
of Matthew I. Kahal

	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

Expert Testimony
of Matthew I. Kahal

	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	N/A	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

Expert Testimony
of Matthew I. Kahal

	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

Expert Testimony
of Matthew I. Kahal

	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

Expert Testimony
of Matthew I. Kahal

	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

Expert Testimony
of Matthew I. Kahal

	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

Expert Testimony
of Matthew I. Kahal

	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

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
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

Expert Testimony
of Matthew I. Kahal

	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

Expert Testimony
of Matthew I. Kahal

	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

Expert Testimony
of Matthew I. Kahal

	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

Expert Testimony
of Matthew I. Kahal

	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

Expert Testimony
of Matthew I. Kahal

	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

Expert Testimony
of Matthew I. Kahal

	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

Expert Testimony
of Matthew I. Kahal

	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

Expert Testimony
of Matthew I. Kahal

	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)

Expert Testimony
of Matthew I. Kahal

	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

Expert Testimony
of Matthew I. Kahal

	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

Expert Testimony
of Matthew I. Kahal

	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

Expert Testimony
of Matthew I. Kahal

	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

Expert Testimony
of Matthew I. Kahal

	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
365.	2010-2213369 April 2011	Duquesne Light Company	Pennsylvania	Consumer Advocate	Merger Issues

	Docket Number	Utility	Jurisdiction	Client	Subject
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
380.	U-32153 July 2012	Cleco Power	Louisiana	Commission Staff	Environmental Compliance Plan

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
381.	U-32435 August 2012	Entergy Gulf States Louisiana LLC	Louisiana	Commission Staff	Cost of equity (gas)
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 and Carriers	Rate of Return (electric and gas)
386.	D-12-049 October 2012	Narragansett Electric Company	Rhode Island	Division of Public Utilities and Carriers	Debt issue
387.	GO12070640 October 2012	New Jersey Natural Gas Company	New Jersey	Rate Counsel	Cost of capital
388.	GO12050363 November 2012	South Jersey Gas Company	New Jersey	Rate Counsel	Cost of capital
389.	R-2012-2321748 January 2013	Columbia Gas of Pennsylvania	Pennsylvania	Office of Consumer Advocate	Cost of capital
390.	U-32220 February 2013	Southwestern Electric Power Co.	Louisiana	Commission Staff	Formula Rate Plan
391.	CV No. 12-1286 February 2013	PPL et al.	Federal District Court	MD Public Service Commission	PJM Market Impacts (deposition)
392.	EL13-48-000 February 2013	BGE, PHI subsidiaries	FERC	Joint Customer Group	Transmission Cost of Equity
393.	EO12080721 March 2013	Public Service Electric & Gas	New Jersey	Rate Counsel	Solar Tracker ROE
394.	EO12080726 March 2013	Public Service Electric & Gas	New Jersey	Rate Counsel	Solar Tracker ROE
395.	CV12-1286MJG March 2013	PPL, PSEG	U.S. District Court for the District of Md.	Md. Public Service Commission	Capacity Market Issues (trial testimony)

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
396.	U-32628 April 2013	Entergy Louisiana and Gulf States Louisiana	Louisiana	Staff	Avoided cost methodology
397.	U-32675 June 2013	Entergy Louisiana and Entergy Gulf States	Louisiana	Staff	RTO Integration Issues
398.	ER12111052 June 2013	Jersey Central Power & Light Company	New Jersey	Rate Counsel	Cost of capital
399.	PUE-2013-00020 July 2013	Dominion Virginia Power	Virginia	Apartment & Office Building Assoc. of Met. Washington	Cost of capital
400.	U-32766 August 2013	Cleco Power	Louisiana	Staff	Power plant acquisition
401.	U-32764 September 2013	Entergy Louisiana and Entergy Gulf States	Louisiana	Staff	Storm Damage Cost Allocation
402.	P-2013-237-1666 September 2013	Pike County Light and Power Co.	Pennsylvania	Office of Consumer Advocate	Default Generation Service
403.	E013020155 and G013020156 October 2013	Public Service Electric and Gas Company	New Jersey	Rate Counsel	Cost of capital
404.	U-32507 November 2013	Cleco Power	Louisiana	Staff	Environmental Compliance Plan
405.	DE11-250 December 2013	Public Service Co. New Hampshire	New Hampshire	Consumer Advocate	Power plant investment prudence
406.	4434 February 2014	United Water Rhode Island	Rhode Island	Staff	Cost of Capital
407.	U-32987 February 2014	Atmos Energy	Louisiana	Staff	Cost of Capital
408.	EL 14-28-000 February 2014	Entergy Louisiana Entergy Gulf States	FERC	LPSC	Avoided Cost Methodology (affidavit)
409.	ER13111135 May 2014	Rockland Electric	New Jersey	Rate Counsel	Cost of Capital

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
410.	13-2385-SSO, et al. May 2014	AEP Ohio	Ohio	Ohio Consumers' Counsel	Default Service Issues
411.	U-32779 May 2014	Cleco Power, LLC	Louisiana	Staff	Formula Rate Plan
412.	CV-00234-SDD-SCR June 2014	Entergy Louisiana Entergy Gulf	U.S. District Court Middle District Louisiana	Louisiana Public Service Commission	Avoided Cost Determination Court Appeal
413.	U-32812 July 2014	Entergy Louisiana	Louisiana	Louisiana Public Service Commission	Nuclear Power Plant Prudence
414.	14-841-EL-SSO September 2014	Duke Energy Ohio	Ohio	Ohio Consumer' Counsel	Default Service Issues
415.	EM14060581 November 2014	Atlantic City Electric Company	New Jersey	Rate Counsel	Merger Financial Issues
416.	EL15-27 December 2014	BGE, PHI Utilities	FERC	Joint Complainants	Cost of Equity
417.	14-1297-EL-SSO December 2014	First Energy Utilities	Ohio	Ohio Consumer's Counsel and NOPEC	Default Service Issues
418.	EL-13-48-001 January 2015	BGE, PHI Utilities	FERC	Joint Complainants	Cost of Equity
419.	EL13-48-001 and EL15-27-000 April 2015	BGE and PHI Utilities	FERC	Joint Complainants	Cost of Equity
420.	U- 33592 November 2015	Entergy Louisiana	Louisiana Public Service Commission	Commission Staff	PURPA PPA Contract
421.	GM15101196 April 2016	AGL Resources	New Jersey	Rate Counsel	Financial Aspects of Merger
422.	U-32814 April 2016	Southwestern Electric Power	Louisiana	Staff	Wind Energy PPAs
423.	A-2015-2517036, et.al. April 2016	Pike County	Pennsylvania	Consumer Advocate	Merger Issues

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
424.	EM15060733 August 2016	Jersey Central Power & Light Company	New Jersey	Rate Counsel	Transmission Divestiture
425.	16-395-EL-SSO November 2016	Dayton Power & Light Company	Ohio	Ohio Consumer's Counsel	Electric Security Plan
426.	PUE-2016-00001 January 2017	Washington Gas Light	Virginia	AOBA	Cost of Capital
427.	U-34200 April 2017	Southwestern Electric Power Co.	Louisiana	Commission Staff	Design of Formula Rate Plan
428.	ER-17030308 August 2017	Atlantic City Electric Co.	New Jersey	Rate Counsel	Cost of Capital
429.	U-33856 October 2017	Southwestern Electric Power Co.	Louisiana	Commission Staff	Power Plant Prudence
430.	4:11 CV77RWS December 2017	Ameren Missouri	U.S. District Court	U.S. Department of Justice	Expert Report FGD Retrofit
431.	D-17-36 January 2018	Narragansett Electric Co.	Rhode Island	Division Staff	Debt Issuance Authority

BEFORE THE

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

PUBLIC UTILITIES COMMISSION

RE: INVESTIGATION OF NARRAGANSETT ELECTRIC COMPANY d/b/a/ NATIONAL GRID FOR APPROVAL OF A CHANGE IN ELECTRIC AND GAS DISTRIBUTION RATES	**)))))**	**DOCKET NO. 4770**

SCHEDULES ACCOMPANYING THE
DIRECT TESTIMONY OF
MATTHEW I. KAHAL

ON BEHALF OF THE

DIVISION OF PUBLIC UTILITIES AND CARRIERS

APRIL 6, 2018

NARRAGANSETT ELECTRIC COMPANY

Provisional Cost of Capital Summary(1)
Pro Forma at June 30, 2017

Electric Operations

Capital Type	Balance(1) (million $)	% Total	Cost Rate	Weighted Cost
Long-Term Debt	$1,081	47.85%	4.69%	2.24%
Short-Term Debt	25	1.11	1.76	0.02
Preferred Stock	2	0.09	4.50	0.00
Common Equity	1,151	50.95	8.5 - 9.00(2)	4.33 - 4.59
Total	**$2,259**	**100.0%**	--	**6.59 - 6.85%**

Gas Operations

Capital Type	Balance(1) (million $)	% Total	Cost Rate	Weighted Cost
Long-Term Debt	$1,081	47.85%	5.10%	2.44%
Short-Term Debt	25	1.11	1.76	0.02
Preferred Stock	2	0.09	4.50	0.00
Common Equity	1,151	50.95	9.00(2)	4.59
Total	**$2,259**	**100.0%**	--	**7.05%**

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(1) Schedules RBH-12, 13, and 14. Reverses OCI adjustment to common equity (about $1 million); assumed $250 million new long-term debt issue is used for refunding of $14.6 million gas First Mortgage Bond that matures in March 2018. This increases short-term debt by $14.6 million and reduces long-term debt by $14.6 million. It also reduces gas cost of long-term debt cost rate from 5.18% to 5.10%.
(2) Schedule MIK-4 and testimony. The 8.5% figure is based on assumption that the Commission approves asymmetric performance incentive earnings for Narragansett potentially valued to provide a reasonable opportunity to increase earnings by at least 0.5% per year.

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
2012	2.1	1.8	0.1	4.1
2013	1.5	2.3	0.1	4.5
2014	1.7	2.5	0.0	4.3
2015	0.1	2.2	0.0	4.1
2016	1.3	1.8	0.0	3.9
2017	2.1	2.3	1.0	4.0

NARRAGANSETT ELECTRIC COMPANY

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

	Annualized Inflation (CPI)	10-Year Treasury	3-Month Treasury	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	3-Month Treasury	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
July	1.4	1.5	0.1	3.9
August	1.7	1.7	0.1	4.0
September	2.0	1.7	0.1	4.0
October	2.2	1.8	0.1	3.9
November	1.8	1.7	0.1	3.8
December	1.7	1.7	0.1	4.0

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
2013				
January	1.6%	1.9%	0.1%	4.2%
February	2.0	2.0	0.1	4.2
March	1.5	2.0	0.1	4.2
April	1.1	1.8	0.1	4.0
May	1.4	1.9	0.0	4.2
June	1.8	2.3	0.1	4.5
July	2.0	2.6	0.0	4.7
August	1.5	2.7	0.0	4.7
September	1.2	2.8	0.0	4.8
October	1.0	2.6	0.1	4.7
November	1.2	2.7	0.1	4.8
December	1.5	2.9	0.1	4.8
2014				
January	1.6%	2.9%	0.0%	4.6%
February	1.1	2.7	0.1	4.5
March	1.5	2.7	0.1	4.5
April	2.0	2.7	0.0	4.4
May	2.1	2.6	0.0	4.3
June	2.1	2.6	0.1	4.3
July	2.0	2.5	0.0	4.2
August	1.7	2.4	0.0	4.1
September	1.7	2.5	0.0	4.2
October	1.7	2.3	0.0	4.1
November	1.3	2.3	0.0	4.1
December	0.8	2.2	0.0	4.0

NARRAGANSETT ELECTRIC COMPANY

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

	Annualized Inflation (CPI)	10-Year Treasury	3-Month Treasury	Single A Utility Yield
2015				
January	(0.1)%	1.9%	0.0%	3.6%
February	0.0	2.0	0.0	3.7
March	(0.1)	2.0	0.0	3.7
April	(0.2)	1.9	0.0	3.8
May	0.0	2.2	0.0	4.2
June	0.1	2.4	0.0	4.4
July	0.2	2.3	0.0	4.4
August	0.2	2.2	0.1	4.3
September	0.0	2.3	0.0	4.4
October	0.2	2.1	0.0	4.3
November	0.5	2.3	0.1	4.4
December	0.7	2.2	0.2	4.4
2016				
January	1.4%	2.1%	0.3%	4.3%
February	1.0	1.8	0.3	4.1
March	0.9	1.9	0.3	4.2
April	1.1	1.8	0.2	4.2
May	1.0	1.8	0.3	4.2
June	1.0	1.6	0.3	4.1
July	0.8	1.5	0.3	3.6
August	1.1	1.6	0.3	3.6
September	1.5	1.6	0.3	3.7
October	1.6	1.8	0.3	3.8
November	1.7	2.1	0.5	4.1
December	2.1	2.5	0.5	4.3

NARRAGANSETT ELECTRIC COMPANY

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

	Annualized Inflation (CPI)	10-Year Treasury Yield	3-Month Treasury	Single A Utility Yield
2017				
January	2.5%	2.4%	0.5%	4.1%
February	2.7	2.4	0.5	4.2
March	2.4	2.5	0.8	4.2
April	2.2	2.3	0.8	4.1
May	1.9	2.3	0.9	4.1
June	1.6	2.2	1.0	3.9
July	1.7	2.3	1.1	4.0
August	1.9	2.2	1.0	3.9
September	2.2	2.2	1.1	3.9
October	2.0	2.4	1.1	3.9
November	2.2	2.4	1.3	3.8
December	2.1	2.4	1.3	3.8
2018				
January	2.1	2.6	1.4	3.9
February	2.2	2.9	1.6	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

List of the Electric/Gas Utility Proxy Companies

	Company	Safety Rating	Financial Strength	Beta	2017 Common Equity Ratio*
1.	American Electric Power	1	A+	0.65	48.5%
2.	Allete	2	A	0.80	59.0
3.	Alliant Energy	2	A	0.70	48.0
4.	Ameren	2	A	0.70	50.5
5.	Black Hills	2	A	0.90	32.5
6.	CenterPoint Energy	3	B+	0.90	32.5
7.	CMS Energy	2	B++	0.65	33.5
8.	Con. Edison	1	A+	0.50	50.0
9.	El Paso	2	B++	0.80	48.5
10.	DTE Energy	2	B++	0.65	44.0
11.	Eversource Energy	1	A	0.65	53.5
12.	Hawaiian Industries	2	A	0.70	55.0
13.	IDACORP	2	A	0.70	56.5
14.	Northwestern	3	B+	0.70	49.5
15.	OGE Energy	2	A	0.95	55.5
16.	Otter Tail	2	A	0.90	58.0
17.	Pinnacle West	1	A+	0.70	51.0
18.	PNM Resources	3	B+	0.75	44.0
19.	Portland General	2	B++	0.70	51.0
20.	Southern Co.	2	A	0.55	33.5
21.	WEC Energy	1	A+	0.60	51.5
22.	Xcel Energy	1	A+	0.60	44.0
	Average	**1.9**	**--**	**0.72**	**47.7%**

*The common equity ratio excludes short-term debt (and current maturities of long-term debt). Actual 2017 equity ratio including short-term debt and current maturities averages 45.5 percent.
Source: *Value Line Investment Survey*, November 17, 2017, December 15, 2017, and January 26, 2018.

NARRAGANSETT ELECTRIC COMPANY

DCF Summary for the
Electric/Gas Company Proxy Group

1.	Dividend Yield (August 2017 – January 2018)[(1)]	3.14%
2.	Adjusted Yield ((1) x 1.0275)	3.2%
3.	Long-Term Growth Rate[(2)]	5.0 – 5.5%
4.	Total Return ((2) + (3))	8.2 – 8.7%
5.	Flotation Expense	0.0%
6.	Cost of Equity ((4) + (5))	8.2 – 8.7%
7.	Midpoint	8.5%
	Recommendation	**9.0%**

[(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 the Electric/Gas Company Proxy Group
(August 2017 – January 2018)

	Company	August	September	October	November	December	January	Average
1.	American Electric Power	3.2%	3.4%	3.3%	3.2%	3.4%	3.6%	3.35%
2.	Allete	2.8	2.8	2.8	2.7	2.9	3.1	2.85
3.	Alliant Energy	2.9	3.0	2.9	2.8	3.0	3.3	2.98
4.	Ameren	2.9	3.0	2.9	2.9	3.1	3.3	3.02
5.	Black Hills	2.5	2.6	2.9	3.3	3.2	3.4	2.98
6.	CenterPoint Energy	3.6	3.7	3.6	3.6	3.8	4.0	3.72
7.	CMS Energy	2.7	2.9	2.8	2.7	2.8	3.0	2.82
8.	Con. Edison	3.3	3.4	3.2	3.1	3.2	3.6	3.30
9.	El Paso	2.4	2.4	2.3	2.2	2.3	2.6	2.37
10.	DTE Energy	2.9	3.1	3.0	3.1	3.3	3.4	3.13
11.	Eversource Energy	3.0	3.1	3.0	2.9	3.0	3.0	3.00
12.	Hawaiian Industries	3.7	3.7	3.4	3.2	3.4	3.6	3.50
13.	IDACORP	2.5	2.5	2.5	2.4	2.5	2.8	2.53
14.	Northwestern	3.5	3.7	3.5	3.3	3.5	3.9	3.57
15.	OGE Energy	3.4	3.7	3.6	3.7	4.1	4.2	3.78
16.	Otter Tail	3.1	3.0	2.8	3.0	2.8	3.1	2.92
17.	Pinnacle West	2.9	3.1	3.1	3.0	3.2	3.5	3.13
18.	PNM Resources	2.3	2.4	2.3	2.1	2.4	2.8	2.38
19.	Portland General	2.9	3.0	2.8	2.7	3.0	3.2	2.93
20.	Southern Co.	4.8	4.8	4.4	4.5	4.8	5.3	4.75
21.	WEC Energy	3.2	3.3	3.1	3.0	3.1	3.5	3.20
22.	Xcel Energy	2.9	3.0	2.9	2.8	3.0	3.2	2.97
	Average	**3.06%**	**3.16%**	**3.05%**	**3.00%**	**3.17%**	**3.43%**	**3.14%**

Source: S&P *Stock Guide*. The January dividend yields are from the YahooFinance website as of January 31, 2018.

NARRAGANSETT ELECTRIC COMPANY

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

	Company	Value Line	Yahoo	Zacks	Reuters	CNN	Average
1.	American Electric Power	4.00%	2.77%	4.75%	2.77%	5.00%	3.86%
2.	Allete	5.00	5.00	7.20	NA	7.20	6.10
3.	Alliant Energy	6.00	7.05	6.36	7.05	6.00	6.49
4.	Ameren	6.00	7.00	7.01	7.00	7.00	6.80
5.	Black Hills	7.50	4.26	5.57	4.26	4.35	5.19
6.	CenterPoint Energy	6.00	7.58	5.72	7.58	7.09	6.79
7.	CMS Energy	6.50	7.44	6.48	7.44	6.91	6.95
8.	Con. Edison	2.50	3.23	2.00	2.94	3.88	2.91
9.	El Paso	5.00	5.30	5.17	5.30	5.17	5.19
10.	DTE Energy	6.00	4.91	6.00	4.90	6.00	5.56
11.	Eversource Energy	6.50	5.92	5.91	5.92	6.10	6.07
12.	Hawaiian Industries	1.50	4.50	4.24	4.50	3.95	3.74
13.	IDACORP	3.50	4.00	4.50	4.14	5.00	4.23
14.	Northwestern	4.50	2.25	1.54	NA	1.71	2.50
15.	OGE Energy	6.00	3.90	4.65	3.9	5.72	4.83
16.	Otter Tail	7.00	5.20	NA	NA	6.20	6.13
17.	Pinnacle West	5.50	5.46	3.23	5.46	5.27	4.98
18.	PNM Resources	7.50	6.05	5.51	6.05	6.00	6.22
19.	Portland General	6.00	4.00	3.80	4.00	4.23	4.41
20.	Southern Co.	3.50	2.59	4.50	3.39	4.50	3.70
21.	WEC Energy	6.00	5.27	5.45	5.27	5.29	5.46
22.	Xcel Energy	4.50	NA	5.47	5.99	5.78	5.44
	Average	**5.30%**	**4.94%**	**5.00%**	**5.15%**	**5.38%**	**5.16%**

Source: *Value Line Investment Survey*, November 17, 2017, December 15, 2017, and January 26, 2018. YahooFinance.com, Zacks.com, CNNMoney.com, Reuters.com, public websites, December 2017.

NARRAGANSETT ELECTRIC COMPANY

Other *Value Line* Measures of Growth
for the Electric/Gas Company Proxy Group

	Company	Dividend per Share	Book Value per Share	Earnings Retention
1.	American Electric Power	5.0%	3.5%	4.5%
2.	Allete	4.5	4.0	3.5
3.	Alliant Energy	4.5	4.0	4.0
4.	Ameren	4.5	4.0	4.0
5.	Black Hills	6.0	5.0	5.0
6.	CenterPoint Energy	3.5	2.0	4.0
7.	CMS Energy	6.5	6.5	5.5
8.	Con. Edison	3.0	3.5	2.5
9.	El Paso	7.0	4.0	4.0
10.	DTE Energy	7.0	4.5	3.5
11.	Eversource Energy	6.0	4.0	4.0
12.	Hawaiian Industries	2.0	3.5	2.5
13.	IDACORP	7.0	4.0	3.5
14.	Northwestern	5.0	4.0	3.5
15.	OGE Energy	9.0	3.5	3.5
16.	Otter Tail	2.0	6.5	4.5
17.	Pinnacle West	5.5	4.0	4.0
18.	PNM Resources	9.0	2.0	4.0
19.	Portland General	6.0	4.0	4.5
20.	Southern Co.	3.5	3.0	3.5
21.	WEC Energy	6.5	5.0	4.0
22.	Xcel Energy	6.0	4.0	3.5
	Average	**5.41%**	**4.02%**	**3.89%**

Source: *Value Line Investment Survey*, November 17, 2017, December 15, 2017, and January 26, 2018. The earnings retention figures are projections for 2020-2022.

NARRAGANSETT ELECTRIC COMPANY

Fundamental Growth Rate Analysis for
Electric/Gas Company Proxy Group

	Company	Shares 2016-2021[1]	% Premium[2]	sv[3]	br[4]	sv + br
1.	American Electric Power	0.0%	107.3%	0.0%	4.5%	4.5%
2.	Allete	1.1	95.6	1.1	3.5	4.6
3.	Alliant Energy	0.7	135.2	1.0	4.0	5.0
4.	Ameren	0.0	106.2	0.0	4.0	4.0
5.	Black Hills	2.7	68.9	1.9	5.0	6.9
6.	CenterPoint Energy	0.2	246.2	0.5	4.0	4.5
7.	CMS Energy	0.7	203.4	1.4	5.5	6.9
8.	Con. Edison	0.6	80.2	0.5	2.5	3.0
9.	El Paso	0.2	85.1	0.2	4.0	4.2
10.	DTE Energy	0.8	116.4	1.0	3.5	4.5
11.	Eversource Energy	0.0	84.3	0.0	4.0	4.0
12.	Hawaiian Industries	0.6	77.7	0.5	2.5	3.0
13.	IDACORP	0.0	86.9	0.0	3.5	3.5
14.	Northwestern	0.9	49.5	0.4	3.5	3.9
15.	OGE Energy	0.2	92.0	0.2	3.5	3.7
16.	Otter Tail	2.3	164.9	3.7	4.5	8.2
17.	Pinnacle West	0.5	76.6	0.4	4.0	4.4
18.	PNM Resources	0.0	63.1	0.0	4.0	4.0
19.	Portland General	0.2	55.4	0.1	4.5	4.6
20.	Southern Co.	0.7	116.9	0.8	3.5	4.3
21.	WEC Energy	0.0	133.7	0.0	4.0	4.0
22.	Xcel Energy	0.3	102.2	0.3	3.5	3.8
	Average			**0.6%**	**3.9%**	**4.5%**

(1) Projected growth rate in shares outstanding; 2016-2021.
(2) % Premium of share price ("Recent Price") over 2016 book value per share.
(3) sv is growth rate in shares x % premium.
(4) br is Value Line projection as of 2020-2022.
Source: *Value Line Investment Survey*, November 17, 2017, December 15, 2017, and January 26, 2018.

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% (Long-term Treasury bond yield for the most recent six months)

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

Beta = 0.72 (See Schedule MIK-3)

C. Model Calculations

Low end:	K_e = 3.0% + 0.72 (5.0) = 6.6%
Midpoint:	K_e = 3.0% + 0.72 (6.5) = 7.7%
Upper End:	K_e = 3.0% + 0.72 (8.0) = 8.8%
High Sensitivity:	K_e = 3.0% + 0.72 (9.0) = 9.5%

NARRAGANSETT ELECTRIC COMPANY

Long-Term Treasury Yields
(August 2017 – January 2018)

Month	30-Year	20-Year	10-Year
August 2017	2.80%	2.55%	2.21%
September	2.78	2.53	2.20
October	2.88	2.65	2.36
November	2.80	2.60	2.35
December	2.77	2.60	2.40
January 2018	2.88	2.73	2.58
Average	**2.82%**	**2.61%**	**2.35%**

Source: Federal Reserve, www.federalreserve.gov website, February 2018.