BEFORE THE

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

PUBLIC UTILITIES COMMISSION

RE: THE NARRAGANSETT ELECTRIC COMPANY: INVESTIGATION AS TO THE PROPRIETY OF PROPOSED TARIFF CHARGES	**))))**	**DOCKET NO. 4065**

DIRECT TESTIMONY OF

MATTHEW I. KAHAL

ON BEHALF OF THE

DIVISION OF PUBLIC UTILITIES AND CARRIERS

SEPTEMBER 15, 2009

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SUMMARY OF POSITION STATEMENT ON FAIR RATE OF RETURN

1. The Company's witness Mr. Moul proposes an overall rate of return of 8.98 percent, including a return on equity ("ROE") of 11.6 percent. This is a sharp increase compared to the Company's currently authorized return on equity of 10.5 percent.

2. The 8.98 percent return purportedly reflects the Company's proposed recapitalization plan recently filed with the Division and the cost of capital effects of the Company's proposed Revenue Decoupling Mechanism ("RDM"). However, Mr. Moul provides no estimate of the incremental effect of the RDM proposal on Narragansett's cost of equity. That is, there is no estimate of Narragansett's cost of capital "with versus without" RDM.

3. Subject to updating, I recommend an overall rate of return of 7.78 percent, including an ROE of 10.1 percent. In addition to finding a substantially lower cost of equity estimate than Mr. Moul, I have three additional cost of capital adjustments.

   a. The cost of long-term debt should be lowered from 6.79 to 6.10 percent.

   b. It would be reasonable to employ a common equity ratio of 47.5 percent instead of 50.0 percent proposed by Mr. Moul.

   c. The cost of short-term debt should be lowered from 2.5 to 1.6 percent.

All of these changes are provisional and subject to updating. My 10.1 percent is based primarily on applications of the Discounted Cash Flow ("DCF") method, which produces a range of 9.7 to 10.7 percent, and it is confirmed by other evidence.

4. The implementation of the RDM, in whole or in part, likely would reduce the Company's risk to investors. This should be considered as a judgmental factor in setting the

authorized return in this case if the Commission accepts some portion or all of the RDM proposed by the Company. That is, my testimony estimates Narragansett's cost of capital today without the RDM structure recommended by Dr. Tierney.

5. Mr. Moul has prepared cost of equity analyses that include inappropriate data inputs, assumptions and "adders" that result in inflated and erroneous estimates of the cost of equity. When corrected, his studies would be generally consistent with my 10.1 percent recommendation.

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DIRECT TESTIMONY
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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 5565 Sterrett Place, Suite 310, Columbia, Maryland 21044.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND.

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

Q. WHAT IS YOUR PROFESSIONAL BACKGROUND?

A. I have been employed in the area of energy, utility and telecommunications consulting for the past 30 years working on a wide range of topics. Most of my work has focused on electric utility integrated planning, plant licensing, environmental issues, mergers and financial issues. I was a co-founder of Exeter Associates, and from 1981 to 2001 I was employed at Exeter Associates as a Senior Economist and

Principal. During that time, I took the lead role at Exeter in performing cost of capital and financial studies. In recent years, the focus of much of my professional work has shifted to electric utility restructuring and competition.

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

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

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

A. Yes. I have testified before approximately two-dozen state and federal utility commissions in more than 300 separate regulatory cases. My testimony has addressed a variety of subjects including fair rate of return, resource planning, financial assessments, load forecasting, competitive restructuring, rate design, purchased power contracts, merger economics and other regulatory policy issues. These cases have involved electric, gas, water and telephone utilities. In 1989, I testified before the U. S. House of Representatives, Committee on Ways and Means, on proposed federal tax legislation affecting utilities. A list of these cases may be found in Appendix A, with my statement of qualifications.

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

A. Since 2001,1 have worked on a variety of consulting assignments pertaining to electric restructuring, purchase power contracts, environmental controls, cost of capital and other regulatory issues. Current and recent clients include the U.S. Department of Justice, U.S. Air Force, U.S. Department of Energy, the Federal

Energy Regulatory Commission, Connecticut Attorney General, Pennsylvania Office of Consumer Advocate, New Jersey Division of Rate Counsel, Rhode Island Division of Public Utilities, Louisiana Public Service Commission, Arkansas Public Service Commission, Maryland Department of Natural Resources and Energy Administration, and MCI.

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

A. Yes. I have testified on cost of capital and other matters before this Commission in gas and electric cases during the past 25 years. A listing of those cases is provided in my attached Statement of Qualifications.

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 distribution utility rate base 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 recommendation to the Division and its consultants for use in calculating the test year annual revenue requirement 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 NG-PRM-1, page 1 of 2, the Company requests an authorized overall rate of return of 8.98 percent. The proposed capital structure is pro forma and is intended to represent the results of the Company's "recapitalization" financing plan. It includes 50.05 percent common equity, 4.98 percent short-term debt, 0.19 percent preferred stock, and 44.78 percent long-term debt. The filed testimony provides little explanation for this capital structure, and instead references a planned securities issuance filing to be made with the Division for support. This filing was made in June 2009 (Division Docket No. D-09-49), and I am currently assisting the Division with the review of that application. The Company requests a return on the common equity ("ROE") component of 11.6 percent. The overall rate of return, cost of debt and cost of equity recommendations are sponsored by the Company's witness, Mr. Paul R. Moul.

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

A. The Company's currently authorized return is based on a 50/50 (debt/equity) capital structure and a 10.5 percent ROE. These parameters originally were set in March 2000 in Docket No. 2930 and affirmed in a Commission-approved Stipulation and Settlement in November 2004 in Docket No. 3617. (Response to Division 4-12) Thus, the Company's proposal in this case is a large increase in the authorized return on equity (from 10.5 to 11.6 percent), and the proposed capital structure is in line with the Settlement capital structure.

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

A. Yes. The proposed capitalization includes a planned $512 million issue of long-term debt scheduled to take place in November 2009 at an assumed all-in cost of 6.79 percent. The debt proceeds will be used both to reduce the short-term debt and common equity balances. I discuss these adjustments 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 2, I am recommending an overall return on Narragansett's utility rate base of 7.78 percent. This includes a return on common equity of 10.1 percent and a capital structure of 52.3 percent total debt (inclusive of short-term debt), 47.5 percent common equity and 0.2 percent preferred stock. This recommendation is provisional and may change with updating. It includes the Company's proposed short-term debt and preferred stock percentages, but it reduces the Company's assumed (or planned) common equity from 50.05 percent to 47.5 percent. While this is not a large change, it brings the ratemaking equity ratio more in line with industry norms and takes into account Narragansett's extremely favorable business risk profile.

After reviewing information on typical industry capital structures, I conclude that a reasonable target range for electric utility common equities today would be roughly 45 to 50 percent. However, given the need to consider both the impacts on customers and the Company, I believe that it is more appropriate at this time to employ the midpoint rather than the upper end of this range. Mr. Moul does not adequately justify the use of the 50.0 percent equity ratio figure.

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

A. Not entirely. Mr. Moul proposes a short-term cost of debt of 2.5 percent which appears to be based on his projections for 2010. I have provisionally proposed a cost rate of 1.6 percent based on the Company's actual cost of short-term debt for the 12 months ending June 2009. I anticipate updating this figure in the rebuttal/surrebuttal phase of this case.

Mr. Moul's 6.79 percent debt cost rate appears to reflect his assumption at the time he filed his testimony of the cost rate for ten year notes to be issued by

Narragansett. Current market conditions, however, support a significantly lower figure, and at this time I am using 6.10 percent. I anticipate that this figure may be updated later in this case.

Q. WHAT IS THE BASIS OF YOUR 10.1 PERCENT RECOMMENDATION FOR THE RETURN ON EQUITY?

A. I am relying primarily upon the standard discounted cash flow ("DCF") model applied to a group of electric distribution utility companies and to a second group of natural gas distribution utility companies. My DCF studies use market data from the six months ending August 2009, obtaining a range of 9.7 to 10.7 percent. My recommendation of 10.1 percent approximates the midpoint and reasonably reflects this range of evidence. I have attempted to confirm my DCF results and recommendation using the Capital Asset Pricing Model (CAPM) as a check. While the CAPM tends to produce a very wide range of cost of equity results, in my opinion, a reasonable application of this methodology using current market data provides estimates in approximately the 8 to 10 percent range when a reasonable range of data inputs is used. The CAPM midpoint is about 9 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. Moul employs a third methodology, i.e., the Risk Premium. While I don't regard this method as particularly useful or reliable, when Mr. Moul's data are updated and properly interpreted, they tend to support the reasonableness of my DCF range of results and recommendation.

Q. DO YOU INCLUDE AN ADJUSTMENT FOR FLOTATION EXPENSE?

A. No. An adjustment for flotation expense is not being proposed in this case by Mr. Moul and would not be appropriate. In fact, Narragansett has an excessive amount of equity, and its recapitalization plan is seeking to reduce it. There simply are no flotation expenses that have or will be incurred, and therefore none to be included in rates.

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 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 relative to other utilities in recent years. In Section III of my testimony, I discuss the risk attributes for the Company cited in recent credit rating reports and elsewhere.

Q. YOUR RETURN RECOMMENDATION AT THIS TIME IS SOMEWHAT LOWER THAN THE SETTLEMENT RETURN ESTABLISHED FOR NARRAGANSETT IN 2000 AND 2004. HOW DOES IT COMPARE TO RETURNS FOR OTHER NATIONAL GRID USA UTILITIES?

A. My recommendation appears to be in line with other returns granted in recent years for the National Grid utility companies. Table 1 below lists the authorized equity returns and equity ratios approved for other National Grid subsidiaries, based on the regulatory decisions rendered during this decade. As this table shows, the average authorized return on equity is 10.06 percent, and the average equity ratio approved for ratemaking is 46.1 percent. In the case of the equity ratio, the ratemaking range has been from about 40 to 50 percent.

I am not in any way suggesting that Rhode Island should follow the lead of other jurisdictions. Indeed, I strongly urge that the Commission evaluate the evidence submitted in this case by the Company, the Division and others. The crucial point is that National Grid subsidiaries have been able to function effectively and maintain strong credit ratings (i.e., single-A) with these authorized returns. The Company has not justified the need to move to a much higher rate of return, and I believe it is financially feasible and appropriate to modestly lower the current Settlement ROE and equity ratio.

Table 1

Authorized Returns for National Grid Utilities
(for returns authorized this decade)

Utility	Authorized ROE	Authorized Common Equity Ratio	Date Established
Keystone Energy	9.8%	45.0%	1/08
Niagara Mohawk Gas	10.2	43.7	5/09
Boston Gas	10.2	50.0	10/03
Energy North Nat. Gas	9.54	50.0	8/08
Narragansett (Gas)	10.5	47.7	12/08
Narragansett (Electric)	10.5	50.0	11/04
Niagara Mohawk Electric	10.6	38.6	2/02
Granite State Electric	9.67	50.0	7/07
National Grid Generation	9.50	40.0	1/04
Average	**10.06%**	**46.1%**	--

Source: Response to Division 4-23

Q. A MAJOR ISSUE IN THIS CASE IS THE PROPOSAL FOR A SO-CALLED REVENUE DECOUPLING MECHANISM (RDM) SPONSORED

BY COMPANY WITNESS DR. TIERNEY. DOES YOUR 10.1 PERCENT RECOMMENDATION ACCOUNT FOR THAT PROPOSAL?

A. Since the Division does not support this proposal, my 10.1 percent return on equity and 7.78 percent overall return include no specific adjustment for the RDM. This topic is addressed by Division witness Oliver, and I take no position on the merits of the RDM proposal as a policy issue. However, I note that if such a proposal were to be adopted, it likely would reduce the Company's risk, shifting that risk onto Narragansett's customers. It therefore would be appropriate for the Commission to consider this risk reducing benefit in setting Narragansett's fair rate of return in this case, if the Commission were to adopt all or some significant portion of the RDM proposal. Unfortunately, there is no way to reliably quantify this risk reduction in terms of a cost of capital reduction. Despite the emphasis it has placed on this issue, the Company itself has failed to identify the magnitude of the cost of capital benefit.

Q. HOW DOES MR. MOUL OBTAIN HIS COST OF EQUITY ESTIMATE OF 11.6 PERCENT?

A. He uses three cost of equity methods – DCF, CAPM and Risk Premium, with the first two applied to a proxy group of seven "RDM electrics." The average of his three studies is about 11.6 percent. He also performs a Comparable Earnings study, but he acknowledges that this is not a market cost of equity method, and it appears to play no role in formulating his recommendation.

As I discuss in the last section of my testimony, Mr. Moul employs certain inappropriate adjustments and inputs in these studies. When corrected (and updated) his studies would support my recommended 10.1 percent.

B. **Capital Cost Trends**

Q. HAVE YOU REVIEWED THE TRENDS IN MARKET CAPITAL COSTS OVER THE PAST DECADE?

A. Yes. My Schedule MIK-2 shows certain capital cost indicators on an annual average basis since 1992 and on a monthly basis during January 2002 –August 2009. The indicators include inflation (as measured by the annual change in the Consumer Price Index or CPI), yields on short-term Treasury Bills, yields on ten-year Treasury notes and single A-rated utility long-term bond yields (published by Moody's).

This schedule shows that despite year-to-year fluctuations there has been a general downward trend in capital costs over most of this time period, at least for long-term securities. Short-term interest rates tend to be governed by Federal Reserve Board ("Fed") monetary policy, and up until about a year and a half ago, the Fed had been tightening (i.e., raising short-term rates) in response to a strengthening economy. In response to a slowing U. S. economy and subsequent sharp recession, severe distress in the housing market and a variety of dislocations in financial markets, the Fed has reversed this trend and pursued an aggressive policy of monetary easing. In addition to lowering interest rates to close to zero, it has taken a number of innovative actions to make liquidity and credit available to financial institutions to help ensure that financial markets can function properly.[1]

As measured by utility bond yields, it appears that capital costs "bottomed out" in mid-2005, with single-A utility bond yields reaching a low point in the mid 5 percent range. Long-term interest rates remained relatively low through most of

[1] In a January 13, 2009 presentation at the London School of Economics, Fed Chairman Bernanke described the Fed's aggressive efforts to lower interest rates and its present policy of "credit easing" using a vast array of monetary tools. These policy initiatives include a dramatic expansion of the Fed's balance sheet to provide credit or credit support to various sectors of the U. S. economy. This speech is available on the Fed's web site, www.federalreserve.gov.

2006 (i.e., long-term utility bond yields at approximately 6 percent), and this continued (with some fluctuations) until late 2008. During the financial/economic crisis conditions of the fourth quarter 2008, long-term corporate bond yields moved up sharply to the 8 to 9 percent range. Since then, the financial crisis has eased considerably, and yields on investment grade corporate bonds have moderated. As shown on page 4 of Schedule MIK-2, during the first half of 2009, single-A utility bond yields declined, returning to the 6.0 to 6.5 percent range, which is roughly consistent with prevailing yields of the last several years, and much lower than bond yields in the early part of this decade.

Yields on Treasury notes have trended downward, with the ten-year note reaching as low as 2.5 percent at the beginning of 2009. The pronounced downward trend in Treasury yields relative to long-term utility bond yields undoubtedly reflected a "flight to quality" behavior by investors as a result of the economic and financial market distress. In recent months long-term Treasury yields have moved up somewhat from these extreme historic low levels. This reflects some sign of economic recovery (or at least stabilization) and an easing of credit spreads, at least for credit worthy corporations such as Narragansett.

Q. ACCORDING TO SCHEDULE MIK-2, THERE HAS BEEN A RECENT UPWARD MOVEMENT IN INFLATION DURING 2008. WHAT ACCOUNTED FOR THAT TREND?

A. The 2008 upward movement in inflation was in response to price spikes for energy and, to some degree, it reflected increased food prices. However, since last summer, this trend has reversed with commodity prices collapsing and overall inflation essentially disappearing. The CPI so far in 2009 shows essentially zero inflation or even negative inflation compared to a year ago. Long-term forecasts for inflation are also modest, i.e., the "consensus" forecast for the GDP deflator is 2.1 percent per year for the next ten years (*Blue Chip Economic Indicators*, March 2009), and consensus inflation forecasts for the next year or two indicate inflation as negligible or less than two percent. There are a number of important forces at work that will tend to hold down long-term inflation and inflationary expectations. Low inflation is a crucially important force at work that tends to lower the utility cost of capital.

Q. YOUR SCHEDULE MIK-2 PROVIDES DATA ON LONG-TERM INTEREST RATES. IS THIS INDICATIVE OF COMMON EQUITY COST RATES?

A. At least in a general sense, I believe that it is. The forces over time that lead to lower yields on long-term debt are likely to also favorably affect the cost of equity, although I would acknowledge that debt and equity cost rates do not necessarily move together in lock step. The favorable cost trends discussed above likely affect Narragansett's equity cost rate associated with providing electric distribution utility service. At the present time, however, the market trends are generally favorable with an improving stock market, declining corporate bond yields and narrowing credit spreads.

There is another force at work favorably impacting the cost of equity – federal tax policy. In 2003, Congress enacted legislation granting very favorable income tax treatment for corporate dividend payments and capital gains. At least for taxable accounts, investors care very much about the tax treatment accorded to their returns. All else equal, lower taxes on returns to equity holders means that investors should be willing to accept lower return for holding common stocks (such as dividend-paying utility companies), particularly as compared to conventional utility bonds which do not enjoy such tax advantages.

Importantly, the DCF method, which uses relatively current market data, can capture the cost of equity implications of such tax advantages. Other methods, such as the historical risk premium (as used by Mr. Moul), cannot do so since these current tax treatments are not reflected in the long-term historical data series.

Q. DO YOU HAVE ANY FURTHER COMMENTS ON THE CURRENT ECONOMIC ENVIRONMENT?

A. Yes. The past year has been a very difficult economic environment that has been characterized by a pronounced economic downturn, rising unemployment and severe financial market distress. In addition, energy and commodity prices escalated sharply and then subsequently reversed course. These difficult conditions have implications for the cost of capital but in conflicting directions. The weakening of the U. S. (and global) economy and extremely low inflation tend to push down the cost of capital, as evidenced by the sharp interest rate reductions in yields on Treasury securities and even the recent moderation in utility bond yields. However, volatility and financial distress can increase the corporate cost of capital by increasing investment risk, at least until confidence in markets and financial stability is reestablished. In this environment, where credit markets are functioning poorly and investment behavior is highly distorted, cost of capital estimation must be approached with caution. Certain assumptions embedded in financial markets may not apply as well as they would under normal circumstances, and this dysfunction can distort cost of capital estimation results.

While there are conflicting signals in financial markets, there have been notable improvements in recent months. In the first half of 2009, financial market volatility has greatly attenuated, and credit spreads over long-term Treasury yields have sharply reduced for credit-worthy utilities (such as Narragansett). The stock market has to some degree recovered from its March 2009 low levels, and corporate debt cost rates have moderated. The Fed has committed itself to maintaining near zero levels of short-term interest rates until an economic recovery takes hold or inflationary pressures become evident. Inflation, however, is simply not on the horizon at the present time. Strong, credit-worthy companies – such as Narragansett – operate in a low inflation and capital cost environment, and this environment is expected to continue for the foreseeable future. Although equity risks remain, at the present time it appears we are in a low capital cost environment, particularly for "safe haven" utilities.

C. <u>Remainder of Testimony</u>

Q. PLEASE DESCRIBE THE ORGANIZATION OF THE REMAINDER OF YOUR DIRECT TESTIMONY.

A. Section III presents my proposals concerning Narragansett's capital structure and cost of debt. This section also briefly discusses the credit rating and business risk assessments. Section IV presents my cost of equity analyses and recommendation. This includes both the DCF and CAPM studies, with the majority of emphasis on the former. Section V is a critique of the cost of equity evidence submitted by Mr. Moul on behalf of Narragansett and his 11.6 percent cost of equity recommendation.

III. CAPITAL STRUCTURE, RISK AND DEBT COSTS

Q. HOW DOES MR. MOUL DERIVE THE COMPANY'S CAPITAL STRUCTURE?

A. He presents the Company's plan for revising the current capital structure which at this time includes an excessive amount of expensive common equity. In doing so, he identifies the Company's plan to issue $512 million (in the form of ten-year notes). The debt proceeds are to be used to reduce common equity and pay off a portion of short-term debt. In addition, he subtracts $725 million of goodwill and $74 million of Other Comprehensive Income ("OCI") from the common equity balance. Since the latter appears to be a negative item on the balance sheet, the removal of OCI would increase the equity ratio for ratemaking purposes.

The end result of these assumed transactions and adjustments is to produce a 50/50 capital structure very similar to the currently authorized Settlement capital structure.

Q. IS THERE ANY WAY TO VERIFY THIS IS WHAT ACTUALLY WILL OCCUR LATER THIS YEAR?

A. No, this is just a plan or set of intentions, and the financial transactions that actually will achieve the recapitalization will occur at a later date. Therefore, the principal consideration should be whether this is the most reasonable capital structure to use for ratemaking in this case, given present circumstances.

Q. DOES MR. MOUL PROVIDE A JUSTIFICATION FOR THIS CAPITAL STRUCTURE?

A. He provides very little support. He cites to the 2004 Settlement (which I understand to be a non-precedential compromise) and certain industry statistics from the *Value Line Investment Survey*, as of February 2009. He claims that the latter indicates an industry average 48 percent common equity ratio with projections that the industry average will increase to 50 percent at some future time. He concludes that the 50 percent equity ratio proposed for Narragansett "is in line with that of the electric utility industry generally." (Testimony, page 2)

Q. DO YOU AGREE WITH MR. MOUL?

A. Not entirely. I agree that 50 percent could be considered to be within the range of what can be observed for electric utilities, but in fact it is somewhat above the industry average. Moreover, since all evidence would indicate the Narragansett is below average in business risk, relative to the industry, it could be argued that Narragansett should use a below average equity ratio to achieve a least-cost capital structure. That is, the lower the business risk, the less equity is needed in the capital structure.

Mr. Moul claims that Value Line identifies an industry average equity ratio of 48 percent. However, the August 28, 2009 edition of that publication identifies an actual electric utility average equity ratio for 2008 of 45.3 percent, with forecasted ratios of 47.0 percent for 2009 and 47.5 percent for 2010 (year end). Moreover, the common equity ratios reported by Value Line are computed *excluding both* short-term debt and long-term debt maturing within one year. This information contradicts Mr. Moul and would suggest that the 50.0 percent sought for Narragansett is clearly above industry norms.

Q. YOU STATED EARLIER THAT YOU ARE EMPLOYING TWO PROXY GROUPS. HAVE YOU COMPUTED EQUITY RATIOS FOR THESE GROUPS?

A. Yes. I have computed common equity ratios for both proxy groups using data from Value Line. Unlike Value Line published figures, my calculations include total debt, inclusive of short-term debt and debt maturing within one year. These calculations indicate an average common equity ratio of 47.4 percent for my gas utility proxy group and 44.8 percent for my electric group.

Q. WHAT DO YOU CONCLUDE?

A. I believe that it is appropriate to consider a reasonable range for the common equity ratio for ratemaking purposes in this case of 45 to 50 percent. Given present circumstances, it would be more reasonable to use the midpoint of this range – 47.5 percent – than the upper end of 50.0 percent. There is no information or analysis in Mr. Moul's testimony (or that of any Narragansett witness) that supports the use of a common equity ratio any higher than 47.5 percent.

In addition to replacing the proposed 50 percent equity ratio with 47.5 percent, I accept as reasonable Mr. Moul's 4.98 percent ratio for short-term debt and 0.19 percent for preferred stock. Therefore, the long-term debt ratio must increase by 2.5 percent to compensate for the 2.5 percent equity ratio reduction.

Q. DO YOU CONSIDER YOUR ADJUSTMENT TO MR. MOUL'S CAPITAL STRUCTURE TO BE A RATEMAKING DISALLOWANCE?

A. No, not necessarily. The capital structure proposed by Mr. Moul is not in place, and in fact, may not actually be achieved. Narragansett has every opportunity under its recapitalization plan (as later approved by the Division) to utilizes a capital structure similar to what I have proposed. In that case, there would be no ratemaking disallowance, since ratemaking then would be in line with the actual capital structure.

A. **<u>Cost of Debt</u>**

Q. HOW DID MR. MOUL DEVELOP HIS COST RATE FOR SHORT-TERM DEBT?

A. According to the response to Division 4-8, Mr. Moul developed a projection of the 2010 average year London Interbank Offered Rate (LIBOR), and he further assumed that the cost of commercial paper (i.e., Narragansett's short-term debt cost rate) would be 0.5 percent higher than LIBOR. Since his LIBOR projection for 2010 is 2.0 percent, this approach provides a 2010 short-term debt cost rate of 2.5 percent.

Q. DO YOU AGREE WITH THIS APPROACH?

A. No, in my opinion it is high speculative and likely greatly overstates the Company's near term cost of short-term debt. So far, his projections have turned out to be dead wrong. For example, his methodology predicts a LIBOR rate for August 2009 of 1.75 percent and therefore a Narragansett cost of short-term debt of 2.25 percent. In fact, Value Line reports current LIBOR (i.e., as of late August) of 0.42 percent and commercial paper rate of 0.23 percent (August 28, 2009 edition). According to the response to Division 4-9, Narragansett's *actual* short-term debt cost rate has been below 1.0 percent this entire year.

In my opinion we are on much more solid ground using actual data than Mr. Moul's projections, which have turned out to erroneous and overstated. The reason why short-term rates have remained low is clear to observers of financial markets – Fed monetary policy. Both the Federal Open Market Committee and Chairman Bernanke have made it clear that the Fed's current policy of near zero short-term interest rates will remain in place for the forseeable future. This has been repeatedly stated in the official Committee meeting minutes (published on the Fed's website) and in Congressional testimony.

Q. WHAT IS YOUR SHORT-TERM DEBT COST RATE RECOMMENDATION?

A. For purposes of my testimony at this time, I am using 1.6 percent. This is well above 2009 levels but reflects the 12-month average ending June 2009. (See page 2 of Schedule MIK-1 for the calculation.) This average includes the very elevated levels of short-term interest rate during last Fall's credit crisis, and it does not fully reflect the change in Fed policy of "quantitative easing." Consequently, I would expect an update to provide a lower measure of Narragansett's cost of short-term debt.

Q. HOW HAS MR. MOUL DEVELOPED HIS ESTIMATE OF THE COST OF LONG-TERM DEBT?

A. He assumes that the Company will issue $512 million of ten-year notes in November 2009, at a projected interest rate of 6.7 percent. He further estimates that adding in debt discount and expense will increase this cost rate to an all-in 6.79 percent.

Q. DO YOU AGREE WITH THIS ESTIMATE?

A. This projection may have been within the range of reasonableness in April 2009 when he prepared his testimony, but it now appears to be too high as we get closer to the November time frame. Interest rates and credit spreads for single-A utilities (i.e., Narragansett's rating) have been declining since April 2009 as indicated on page 4 of Schedule MIK-2. The most recent full month of data (i.e., for July) indicates a cost rate for single-A long-term bonds of 6.0 percent (for 20 to 30-year bonds). Moreover, one would expect ten-year notes to carry an even lower cost rate.

Q. ARE YOU AWARE OF A UTILITY SIMILAR IN CREDIT QUALITY TO NARRAGANSETT THAT HAS RECENTLY ISSUED TEN-YEAR NOTES?

A. Yes. In early August, a subsidiary of the gas utility company AGL Resources issued $300 million in ten-year senior notes at a cost rate (before expenses) of 5.28 percent. The AGL subsidiary issuing the notes is rated Baa(1) by Moody's and BBB+ by Standard & Poor's (S&P), slightly weaker ratings than Narragansett. The yield spread over Treasury notes for this issue is 163 basis points, which is a dramatic improvement compared to spreads six to nine months ago. (Source: Reuters, "New Issue – AGL Capital sells $300 mln in 10-Year Notes," August 5, 2009)

Q. ARE YOU ADOPTING THE AGL COST RATE?

A. No, not at this time. Even though Mr. Moul assumes the issue will be ten-year notes, it is not clear this is what Narragansett will actually do. The Company's debt issuance application before the Division contemplates a wide range of potential debt structures with terms as long as 30 or 40 years. Therefore, at this time, I am utilizing a more conservative cost rate of 6.0 percent, and an all-in cost, including debt expense, of 6.1 percent. This assumed cost rate is provisional and if new information is available, I anticipate updating this cost rate.

Q. DO YOU HAVE ANY OTHER COMMENTS ON CAPITAL STRUCTURE AND COST OF DEBT?

A. Yes, I have a number of concerns that I expect to explore in the Company's financing docket now pending before the Division. In particular, I question whether it is prudent for Narragansett to be issuing this amount of long-term debt at one time and in only one type of debt instrument and term. Hence, my testimony in this case should not be interpreted as concurrence with or endorsement of the Company's recapitalization plan proposal.

B. <u>Discussion of Business Risk</u>

Q. MR. MOUL'S TESTIMONY DISCUSSES THE TURMOIL IN FINANCIAL MARKETS AND NARRAGANSETT'S BUSINESS RISKS. DO YOU AGREE WITH HIS DISCUSSION?

A. His discussion at best is incomplete and to some extent outdated. My testimony already mentions the improvement in financial markets and stabilization that has occurred since the time frame when he prepared his testimony. Of course, difficulties with financial institutions and credit availability to some degree remain, but credit spreads for utility bonds relative to Treasury securities have narrowed substantially, even though the U.S. economy remains quite weak. Moreover, this weakness helps to keep inflation in check and capital costs low.

While it is true that risks are elevated for many types of equity investments (as one would expect in a severe economic downturn), there is a "safe haven" quality to investing in utility stocks. Value Line, a publication normally not particularly favorable to utilities, has recently expressed this point of view for gas and electric utilities. In its June 12, 2009 report on the gas utility group, Value Line notes that utilities are well regarded by investors due to their "defensive characteristics."

> Natural Gas utilities tend to offer predictable cash flows, healthy dividend yields, and generally have solid balance sheets. Accordingly, these stocks have been increasingly sought after by investors over the past year. (Value Line, page 446, June 12, 2009)

Value Line's industry report further notes that these companies have "provided fairly safe haven amid the recessionary environment" and it notes gas utility "steady cash flow." *Id*. Value Line also cautions that gas company non-regulated operations, while relatively modest in size, "add a greater degree of risk to the businesses that utilize the strategy." *Id*.

Value Line offers similar comments for electric utilities. The August 28, 2009 edition (page 147) states: "During these challenging times, utility stocks are still sought after due to their relative stability and attractive dividend yields …. All told, we believe this might be a good time to increase your portfolio's electric-utility exposure."

Q. YOU HAVE CITED VALUE LINE'S OPINION CONCERNING THE "SAFE HAVEN" INVESTMENT ATTRIBUTES OF UTILITY STOCKS. IS THERE OBJECTIVE DATA AVAILABLE THAT SUPPORTS THIS VIEW?

A. Yes. During the economic and financial turmoil of the past year, there has been pronounced stock market volatility. By comparison utility stocks have been far more stable, particularly for utility companies not burdened by the exposure of substantial non-utility operations. One measure of this improvement is the trend in utility "betas" (a measure of a company's stock price volatility relative to the overall stock market) during the past year. Table 2 below compares betas published by Value Line for my nine proxy gas utilities and seven proxy electric distribution utilities in June 2008 versus betas in June 2009. This table demonstrates that in June 2008 the betas for the proxy utilities averaged 0.87, whereas by June 2009 they have declined sharply to about 0.7. This indicates a major reduction in the relative risk within the past year for investing in utility stocks compared to common stocks generally.

Table 2

Utility Betas Comparison
(June 2008 vs. June 2009)

Gas Utilities	2008	2009
AGL Resources	0.85	0.75
Atmos	0.85	0.60
LaClede	0.90	0.65
NICOR	0.95	0.75
Northwest Natural	0.80	0.60
Piedmont Natural	0.85	0.65
South Jersey	0.85	0.65
Southwest Gas	0.90	0.70
WGL	0.90	0.65
Average	**0.87**	**0.67**
Electric Utilities		
CH Energy	0.90	0.65
Central Vt.	1.10	0.80
Consolidated Edison	0.75	0.65
Northeast Utilities	0.75	0.70
NSTAR	0.80	0.65
PEPCO	0.90	0.80
UIL	0.90	0.70
Average	**0.87**	**0.71**

(Source: *Value Line Investment Survey*, June 13, 2008, June 12, 2009)

Q. DOES NARRAGANSETT SHARE IN THIS RISK REDUCTION?

A. Yes, very much so. Narragansett, of course, is not a publically-traded company, but as a distribution electric utility it would have the same risk reduction attributes that investors would find attractive for utilities generally.

Q. WHAT IS THE ASSESSMENT OF CREDIT RATING AGENCIES?

A. The Company has supplied its recent credit rating reports in response to Division 4-2 and Commission 1-10 for itself and National Grid parent. The credit ratings for Narragansett (and the various National Grid USA affiliates) are quite strong. Moody's March 2009 report assigns Narragansett an Issuer rating of A3, with senior debt rated A2. These are slightly higher ratings than given by Moody's for National Grid USA and the ultimate parent, National Grid PLC. Similarly, S&P assigns

Narragansett a corporate rating of A- and a double-A rating for its senior secured debt. In addition, S&P assigns Narragansett a rating of "Excellent" for its business risk, which is S&P's highest (i.e., most favorable) category. S&P further emphasizes that Narragansett's credit ratings "reflect the consolidated profile of its parent National Grid USA."

Q. DO THE CREDIT RATING AGENCIES EXPLAIN THE BASIS FOR THE FAVORABLE RATINGS?

A. Yes. S&P summarizes its qualitative assessment of Narragansett's business risk as follows:

> Narragansett's excellent business position reflects its low operating risk electricity operations, a supportive regulatory environment, a largely residential and commercial customer base (about 90% of revenues) without any significant customer concentration, and robust economic conditions in the service territory, which should ensure modest load and customer growth. Narragansett's business risk profile is excellent. (March 11, 2009, report, page 2)

Moody's places similar emphasis on Narragansett's low risk distribution utility operations.

> Our assessment also assigns significant weighting to the fact that Rhode Island is one of the more predictable and supportive regimes in the U.S. on the regulatory spectrum. (March 23, 2009 report) NEC's low business risk profile stems from its stable business activities which should continue to generate predictable earnings and cash flow over the long-term horizon.

Despite this very favorable assessment and the single-A rating, Moody's includes a "negative" outlook for Narragansett. The report explains that the negative outlook reflects concerns that National Grid parent may require Narragansett to make large dividend payments in order to help the parent service the large amount of debt taken on by National Grid PLC in connection with the recent acquisition of Keyspan. Moody's believes that it is the parent's financial policies that are of concern, and Narragansett "will continue to generate stable and predictable cash flow." (*Id*.)

Q. HOW HAVE YOU ATTEMPTED TO INCORPORATE THESE FAVORABLE RISK ASSESSMENTS IN YOUR COST OF EQUITY STUDIES?

A. I have done so by selecting two proxy groups of companies that are predominantly utility companies. Moreover, these are companies whose principal activity is distribution or delivery service, and in that respect they are comparable to Narragansett. I believe that these utility companies, on average, are similar to or even slightly riskier than Narragansett.

Q. HAS MR. MOUL FOLLOWED THE SAME APPROACH OF UTILIZING COMPANIES SIMILAR IN BUSINESS RISK TO NARRAGANSETT?

A. I do not believe he has successfully done so. He instead has selected a group of seven electric companies, with the primary screening criteria being whether the company (or some portion of the company) is allowed to employ some form of revenue decoupling. He does so without establishing or even offering any evidence that revenue decoupling is considered by investors to be a major comparability or risk factor. In establishing his group, he permits risky non-utility operations to account for as much as 40 percent of the proxy company's business. Moreover, he includes mostly vertically-integrated companies, including those with large extensive nuclear power operations, as risk proxies for Narragansett's monopoly distribution business.

IV. COST OF COMMON EQUITY CALCULATIONS

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 incentives to invest.

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 return requirements), and it therefore must be estimated using analytic techniques. The DCF model is one such prominent technique 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 operations on reasonable terms. Certainly, it has been my experience that setting the return equal to a reasonable estimate of the cost of capital has permitted utilities to operate successfully and attract capital. Moreover, 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 sought rate of return adders as a reward for asserted good management performance. In this case, it does not appear that the Company is making an explicit request for a performance adder, and therefore the issue is one of *measuring* the cost of equity, not whether a properly measured cost of equity is a fair return.

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. In that regard, there are two key factors that determine this price. First, a company's cost of equity is determined by the fundamental conditions in capital markets (e.g., outlook for inflation, monetary policy, changes in investor behavior, investor asset preferences, the general business environment, etc.). The second factor (or set of factors) is the business and financial risks of the company in question. For example, the fact that a utility company effectively operates as a regulated monopoly, dedicated to providing an essential service (in this case electric utility service), typically would imply very low business risk and therefore a relatively low cost of equity. Narragansett's relatively low business risks and the favorable assessment of the Company by the various credit rating agencies discussed in Section III are indicative of its low cost of equity.

Q. DOES MR. MOUL INCORPORATE THESE PRINCIPLES IN HIS TESTIMONY?

A. In general, I believe he attempts to incorporate these principles in conducting his DCF analysis. However, some of his non-DCF analyses do not adhere as closely to these principles. For example, Mr. Moul's risk premium and comparable earnings studies make excessive use of historical or non-market (i.e., pure accounting-type) data to derive equity return results.

Q. WHAT METHODS ARE YOU USING IN THIS CASE?

A. I employ both the DCF and CAPM models, applied to two proxy groups of utility companies. However, for reasons discussed in my testimony, I emphasize the DCF model results in formulating my recommendation. It has been my experience that most utility regulatory commissions (federal and state) heavily emphasize the use of the DCF model to determine the cost of equity and setting the fair return. As a check (and partly to respond to Mr. Moul), I also perform a CAPM study which also is based on the same proxy group companies 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 by this Commission in past cases. 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 is also transparent and understandable to regulators. 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, which is the cost of equity.

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 (or not fully realistic) in many cases, for traditional utilities or groups of utility companies (which tend to be more stable than most unregulated companies) the assumption generally is reasonable, particularly when applied to a group of companies.

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 USA, and therefore a market proxy is needed. The latter is owned by National Grid PLC, which is a foreign company. More important, I am reluctant to rely upon a single-company DCF study (nor does Mr. Moul), although in theory that approach could be used.

In any case, I believe that an appropriately selected proxy group (preferably one reasonable in size) is likely to be 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 at least at least several months (i.e., 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" utility rates that are likely to be in effect for several years. The practice of averaging market data over a period of several months can add stability to the results. Mr. Moul also adopts the practice of averaging market data over a period of months.

Q. ARE YOU EMPLOYING THE DCF MODEL USING UTILITY PROXY GROUPS?

A. As discussed further, I am employing two proxy groups of companies that are predominantly utility delivery services (i.e., "wires and pipes"), and therefore reasonably comparable to Narragansett. The first group consists of nine companies that are classified as gas distribution utilities. There are 12 such companies in the Value Line data base, and I have selected nine of the 12. My second group consists of companies classified as electric utilities that (like Narragansett) operate in Northeastern restructured markets and function primarily as electric delivery service companies, i.e., are not vertically integrated. There are seven such electrics in this second group, bringing the total to 16 companies for both groups combined.

Q. WHAT VALUE LINE GAS COMPANIES HAVE YOU ELIMINATED?

A. I have eliminated New Jersey Resources, UGI and NiSource. The first two have been eliminated due to their relatively large non-regulated operations, and NiSource is a vertically-integrated electric company. With these three eliminations, I have a proxy group of nine companies that operate predominantly as monopoly utilities.

B. <u>DCF Study Using the Proxy Group of Gas Distribution Utility Companies</u>

Q. PLEASE DESCRIBE YOUR GAS PROXY GROUP.

A. The nine gas utility companies in my group of proxy companies are listed on Schedule MIK-3, page 1 of 2, along with several risk indicators. The measures include Value Line's Safety and Financial Strength ratings, beta and the 2008 common equity ratio. In my opinion, these companies (on average) are reasonably comparable in risk to Narragansett.

It should be noted that although the proxy companies are primarily regulated utilities, some also have some non-regulated operations that may be perceived as somewhat riskier than utility operations (e.g., energy marketing). I make no specific adjustment to my DCF cost of capital results or my final recommendation for the effects of those potentially riskier non-regulated operations.

Q. HAVE EITHER YOU OR MR. MOUL PROPOSED A SPECIFIC RISK ADJUSTMENT TO THE COST OF EQUITY BETWEEN THE PROXY COMPANIES AND NARRAGANSETT?

A. No, not specifically. However, Mr. Moul links his DCF and CAPM studies to the RDM proposal, and he does not provide an alternative recommendation in the event that the Company's sweeping RDM proposal is not adopted. As mentioned earlier, while I have not quantified an adjustment for revenue decoupling, if this regulatory feature is adopted, its cost of capital reducing benefits should be considered in the Commission's consideration of fair rate of return.

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

A. I have elected to use a six-month time period to measure the dividend yield component (Do/Po) of the DCF formula. Using the Standard & Poor's *Stock Guide*, I compiled the month-ending dividend yields for the six months ending August 2009,[2] the most recent data available to me as of this writing. This covers nearly all of the first half of 2009, a period of some financial distress but also some gradual improvement in markets, as noted by the Fed Chairman Bernanke this summer.

I show these dividend yield data on page 2 of Schedule MIK-4 for each month and each proxy company, March through August 2009. Over this six-month period the group average dividend yields were relatively stable, but gradually diminishing over this period, ranging from a low of 4.31 percent in August to 4.90 percent in May 2009, averaging 4.57 percent for the full six months.

For DCF purposes and at this time, I am using a proxy group dividend yield of 4.57 percent.

Q. IS 4.57 PERCENT YOUR FINAL DIVIDEND YIELD?

A. Not quite. Strictly speaking, the dividend yield used in the model should be the value the investor expects over the next 12 months. Using the standard "half year" growth rate adjustment technique, the DCF adjusted yield becomes 4.7 percent. This is based on assuming that half of a year of dividend growth is 2.75 percent (i.e., a full year growth is 5.5 percent).

Q. DOES MR. MOUL EMPLOY THE SAME GROWTH RATE ADJUSTMENT?

A. No, I do not believe so. Based on his exhibits it appears that he incorporates a quarterly compounding effect that is both non-standard and incorrect. The "0.5 g"

[2] On a provisional basis, I am using end of August dividend yields obtained from the YahooFinance.com website since S&P data for August are not yet available. This will be updated using the S&P publication at the appropriate time.

method that I use has become widely employed by rate of return practitioners. While our methods of adjustment appear to differ, the magnitude of the difference is very minor.

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 always reliable as prospective measures. This is due in part to extensive corporate or financial restructuring, particularly in the electric industry. I note that Mr. Moul cites to historical growth rates as an indicator, but he does not give it much weight (or apparently any weight). However, he does rely on historic data for his risk premium study, which seems to be inconsistent.

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 and published by securities analysts. It appears that Mr. Moul places exclusive weight on this information for his DCF studies, and I agree that it warrants substantial though not necessarily exclusive emphasis, particularly in light of current conditions.

Q. WHAT ARE THE DIFFICULTIES OF USING PROJECTED EARNINGS GROWTH AT THIS TIME?

Conditions are presently very unusual in that 2008 to 2009 is a period of a particularly severe recession. This means that there is a danger today that the analyst earnings growth rates reported in publications (or on the Internet) reflect the assumption of economic recovery over the next several years from very depressed current levels. This does not mean these growth rates are "wrong," but it does mean that they may overstate the long-term, sustained growth rate that the DCF model requires. While I believe this is a much less serious problem for utilities than unregulated companies, it does suggest the need for caution in utilizing these projections data, and the need for corroborating or checking the raw published growth rates against other pertinent measures of growth. I have done so in my testimony, but I believe Mr. Moul has not.

S&P, which publishes projected earnings growth rates in its *Earnings Guide*, warns of this problem and urges caution in its "How to Use the Earnings Guide" instructions:

> A company which has reported poor or negative earnings may show a high projected growth rate due to its small [earnings] base.

Q. PLEASE DESCRIBE YOUR GROWTH RATE EVIDENCE.

A. Schedule MIK-4, page 3 presents four well-known sources of projected earnings growth rates. Three of these four sources -- First Call, Zacks and CNNfn -- provide averages from securities analyst surveys conducted by or for these organizations (typically reporting the median value). The fourth, Value Line, is that organization's own estimates. Value Line publishes its own projections using annual average earnings for a base period of 2006-2008 compared to a forecast period of 2012-2014.

As this schedule shows, the growth rates for individual companies vary somewhat among the four sources, but none of the four differs greatly from the overall average. These proxy group averages are 5.6 percent for CNNfn, 5.39 percent for First Call, 5.90 percent for Zacks and 4.11 percent for Value Line. It should be noted that Value Line is somewhat lower than the other three sources, while Zacks is somewhat higher. For that reason, it is particularly useful to average together the four sources, which produces an overall average of 5.3 percent. To recognize uncertainty, I have identified a reasonable range of 5.0 to 5.5 percent which surrounds the 5.3 percent average.

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 from securities analysts. Consequently, while securities analyst estimates should be considered and given substantial weight, these growth rates should be subject to a reasonableness test and corroboration, to the extent feasible.

On Schedule MIK-4, page 4 of 4, I have compiled three other measures of growth published by Value Line, i.e., growth rates of dividends and book value per share and 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 as dividends.) As shown on this schedule, these growth measures tend to be similar to or less than analyst growth projections. For the group, dividend growth averages 3.3 percent, book value growth averages 4.3 percent, and earnings retention growth averages 4.8 percent. These three measures would tend to support gas utility DCF growth rates somewhat less than 5.0 percent, although I would give little weight to dividend growth.

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 August 2009 is 4.7 percent for this group. Available evidence would support a long-run growth rate in the range of approximately 5.0 to 5.5 percent (or less), as explained above. Summing the adjusted yield and growth rates produces a total return range of 9.7 percent to 10.2 percent, and a midpoint result of 10.0 percent. I use these results in conjunction with my second DCF study and my CAPM results to develop a final recommendation of 10.1 percent.

Q. DO YOU INCLUDE AN ADJUSTMENT FOR FLOTATION EXPENSE?

A. A company can incur flotation expenses when engaging in a public issuance of common stock to support its growth in investment. It might choose to do so and incur this cost if retained earnings growth (and other capital sources such as dividend reinvestment programs) are insufficient to provide the needed equity capitalization. A public issuance typically involves significant underwriting fees and other administrative expenses, which the utility may seek to recover as a cost of equity adder.

In this case, there is no evidence such costs are either present or will be incurred. Indeed, Narragansett's "problem" is its need to reduce common equity, not increase it. Consequently, I am not including an adjustment for flotation expense.

Q. THIS CASE IS INTENDED TO SET RATES FOR NARRAGANSETT'S ELECTRIC OPERATIONS. WHY ARE YOU USING A GAS PROXY GROUP?

A. This is because local gas distribution companies provide an excellent risk proxy for an electric distribution company. If there was available a robust group of "pure play," publically-traded electric distribution companies, then arguably, the gas utility group would not necessarily be needed. Unfortunately, that is not the case today. I was hard pressed to assemble a group of seven such distribution electrics, and Mr. Moul was not able to do so at all.

In that regard, it also is important to point out that Mr. Moul's group actually includes *both* gas and electric operations. For examples, such companies in his group including Pepco, Con Ed, Sempra and Pacific Gas and Electric are actually both gas and electric utilities. Therefore, it is not a question as to *whether* gas distribution should be included as a risk proxy, but *how* they should be included.

Q. DO YOU HAVE ANY EVIDENCE THAT GAS DISTRIBUTION AND ELECTRIC DISTRIBUTION UTILITY OPERATIONS ARE VIEWED AS SIMILAR?

A. Yes. In 2004, S&P developed and implemented a new system for ranking the business risks of utility and power companies.[3] Companies were placed for business risk comparative purposes into five categories:

1. Transmission and distribution – water, gas and electric
2. Transmission only – electric, gas and other
3. Integrated electric, gas and combination utilities
4. Diversified energy and diversified non-energy
5. Energy merchant/power, developer/trader, marketing

[3] "New Business Profile Scores Assigned for U. S. Utility and Power Companies; Financial Guidelines Revised," June 2, 2004.

Narragansett was included by S&P in Category (1), with the gas distribution companies for business risk purposes. In that regard, Narragansett was assigned a risk profile rating of "1" (on a scale of 1 to 10) and today continues to be ranked for business risk as "excellent". (S&P recently moved to a more streamlined system for ranking utility business risks.)

It is important to note that vertically-integrated electrics (the business type that dominates Mr. Moul's proxy group) are in a totally separate risk group that excludes Narragansett. This is an indication that as a general matter, S&P views vertically-integrated operations as somewhat riskier than distribution. The riskiest category of all is unregulated merchant generation and marketing, and some of Mr. Moul's seven companies are active in those lines of business.

What this demonstrates is that gas distribution companies are superior to vertically-integrated electrics as a risk proxy for Narragansett. The absolute worst proxy would be a company with substantial merchant generation (or other unregulated operations).

Q. DOES NARRAGANSETT ALSO HAVE GAS DISTRIBUTION OPERATIONS?

A. Yes. It is my understanding that at the present time Narragansett's gas and electric operations have the same authorized return on equity, i.e., 10.5 percent.

C. Electric Company DCF Study

Q. HOW DID YOU SELECT YOUR ELECTRIC COMPANY PROXY GROUP?

A. In order to develop a group of publically-traded companies that would be a good risk proxy for Narragansett, I consulted the *Value Line Investment Survey* East Region electric utility group. I selected electric utility companies that operate primarily as delivery service utilities and do not have risk profiles that are unduly influenced by non-regulated (mainly merchant power) activities. In doing so, I eliminated all companies that operate south of Maryland since all of those electrics (listed in Value Line) are vertically integrated. For the same reason, I eliminated several Northeast companies that are major players in the unregulated merchant power industry, even though they also may have electric distribution subsidiaries. Excluded companies include Public Service Enterprise Group, Exelon, Constellation Energy, PPL Corp., Duke Energy and FirstEnergy. In my opinion, the merchant power operations dominate these companies' growth and profitability outlook, and they cannot serve as effective risk proxies for Narragansett.

Using these criteria, I selected seven companies, and they are listed on page 2 of Schedule MIK-3, along with their risk attributes. Please note that for the group as a whole the risk measure averages are very close to those of the gas utility proxy group on page 1 of that Schedule.

Q. IS THIS A REASONABLY HOMOGENOUS GROUP OF COMPANIES?

A. Yes, I believe so, with perhaps two exceptions. All seven companies are located in the Northeast and operate in one of three Regional Transmission Organizations ("RTOs"), i.e., PJM, New York ISO or New England. All are engaged primarily in electric delivery service. One company, Central Vermont, is slightly different from the other companies since it strictly speaking remains integrated and does not provide retail access. However, like the others it purchases the vast majority of its generation supply from market sources. This technical distinction does not warrant excluding this company.

Another company, Pepco, is also primarily a delivery service utility, but it has substantial non-regulated operations, including both energy marketing and merchant generation. These non-regulated activities are quite meaningful but vastly smaller than those of other merchant generators in the region such as Constellation or Exelon. It could be argued that Pepco should be disqualified from this proxy group, and doing so would slightly lower my DCF results. However, given that my group is already relatively small and Mr. Moul already selected Pepco for his proxy group, I have chosen to retain that company.

Q. DID YOU INCLUDE ANY CENTRAL OR WEST UTILITIES?

A. No. All or nearly all Value Line electrics from the Central or West regions are either vertically integrated (meaning they have their own regulated generation assets) or they have substantial non-regulated operations (or both). For that reason, I restrict my proxy group to East region electrics.

Q. HOW HAVE YOU CONDUCTED YOUR DCF STUDY FOR THIS GROUP?

A. I conducted my study in a manner very similar to my gas utility DCF study. I present my supporting data and calculations on Schedule MIK-5, pages 1-4. As shown on page 2 of that schedule, the dividend yield for the six months ending August 2009 is 5.81 percent. Using the standard "0.5g" forward adjustment, the going forward yield becomes 5.9 percent.

Please note that there has been a pronounced downward trend in dividend yields for these companies during this six-month period. This is consistent with the observed improvement in financial markets.

Q. HOW DID YOU DEVELOP YOUR GROWTH RATE ASSUMPTIONS?

A. For DCF purposes, I am using a growth range of 3.8 to 4.8 percent. Page 3 of Schedule MIK-5 shows the forecasted earnings growth rates from the same four sources used in my gas utility DCF study (Value Line, First Call, Zacks and CNNfn). This produces a proxy group average of 4.87 percent. While the projected earnings growth rates at this time may overstate expected long-term growth, as discussed earlier, I am using this result to support the upper end of my 3.8 to 4.8 percent growth range.

Page 4 of 4 of Schedule MIK-5 presents three prospective growth measures published by Value Line – dividends per share, book value per share and earnings retention growth (growth from reinvesting earnings). Dividend growth is a very low 1.86 percent and tells us little about long-term growth expectations. Book value and earnings retention growth for this group average 3.8 and 3.5 percent, respectively. I am using these two measures to support the lower end of the growth range for this group, i.e., 3.8 percent. Averaging the three measures together would produce a growth rate of 4.0 percent.

Q. USING THESE DATA INPUTS, WHAT IS YOUR ESTIMATED DCF COST RATE FOR THIS GROUP?

A. The DCF cost of equity is the adjusted yield (4.9 percent) plus growth ravage (3.8 to 4.8 percent), or 9.7 to 10.7 percent. Again, a flotation cost adjustment is not needed. The midpoint of this range is 10.2 percent, which is slightly higher though similar to my gas utility proxy group DCF study result.

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 Mr. Moul's three cost of equity methods. (He also employs a Risk Premium study, and his Comparable Earnings is not a market cost of equity method.)

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 Mr. Moul uses those betas to the exclusion of all other sources. The greatest difficulty, however, is in the measurement of the expected stock market return (and therefore the risk premium), since that variable cannot be directly observed.

While the beta itself also is “observable,” different investor services provide different estimates of betas depending on the calculation methods that they use. Potentially, these differences can have large impacts on the CAPM results. In this case, both Mr. Moul and I use Value Line published betas, but I note that other sources have somewhat different (and lower) utility betas, which would yield lower results. For that reason, I have incorporated other published sources, along with Value Line, to obtain a range of betas for comparative purposes. This is analogous to the procedure followed by Mr. Moul and me in using multiple published sources for DCF earnings growth rates rather than relying on just one source.

Q. HOW HAVE YOU APPLIED THIS MODEL?

A. For purposes of my CAPM analysis, I have used a long-term Treasury yield as the risk-free return along with the average beta for the natural gas and electric proxy company groups. (See Schedule MIK-6, page 3 of 3, for the company-by-company betas.) In last six months, long-term Treasury yields have averaged approximately 4.0 percent, and the recent Value Line betas for my proxy group average 0.67 and 0.71 for the gas and electrics, respectively. However, the Value Line betas generally tend to be higher than other available published betas, and the proxy group average for the three public sources that I have identified (Value Line, Yahoo Finance and MSN Money) averages to about 0.5. I note that Mr. Moul has elected to use a beta of

0.78 for his proxy companies (obtained from Value Line with his inappropriate market/book adjustment). Considering this range of evidence, I am using a conservatively high beta of 0.7, which is the approximate average of my gas and electric Value Line betas. Finally, and as explained below, I am using a stock market equity risk premium range of 5 to 8 percent, although I see much less support for the upper end of that range.

Using these data inputs, the CAPM calculation results are shown on page 1 of Schedule MIK-6. My low-end cost of equity estimate uses a risk-free rate of 4.0 percent, a proxy group beta of 0.70 and an equity risk premium of 5 percent.

$$K_e = 4.0\% + 0.7\ (5.0) = 7.50\%$$

The upper end estimate uses a risk-free rate of 4.0 percent, a proxy group beta of 0.70 and an equity risk premium of 8.0 percent.

$$K_e = 4.0\% + 0.7\ (8.0) = 9.60\%$$

Thus, with these inputs the CAPM provides a cost of equity range of 7.5 to 9.6 percent, with a midpoint of 8.6 percent. The CAPM analysis produces a midpoint result lower than the range of results from my gas and electric group DCF analyses, but I have not placed substantial reliance on the CAPM returns in formulating my return on equity recommendation in this case. This is because long-term Treasury yields at this time are somewhat lower than normal low due to the “flight to quality” problem that I discussed earlier. At the present time, the CAPM may somewhat understate the utility cost of equity, but it does confirm that my 10.1 percent recommendation is not unduly low.

Q. WHAT RESULT WOULD YOU OBTAIN USING MR. MOUL’S MARKET RISK PREMIUM?

A. For his CAPM studies, Mr. Moul has selected a market risk premium of 8.8 percent. As will be explained later, the 8.8 percent figure is outside the range of reasonableness and results from certain errors in Mr. Moul's analysis. Nonetheless, if used in conjunction with a current utility beta of 0.7 (based on Value Line data) and a 4.0 percent Treasury bond yield, the CAPM produces:

$$K_e = 4.0\% + 0.7\ (8.8\%) = 10.16\%$$

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 risk premium to use would be about 6 percent, which today would imply a stock market return of roughly 10.0 percent (i.e., 6.0 + 4.0 = 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 an annualized market equity return of about 9 to 12 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*, 8th Edition) 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)

I would note that Mr. Moul's 8.8 percent premium exceeds even the upper bound of that range, while my "preferred" 6 percent is also well within that range, close to the midpoint.

There is one important caveat to consider here regarding the 5 to 8 percent range that the authors believe is supported by the professional risk premium literature. It appears that the 5 to 8 percent range is specified relative to short-term Treasury bill yields, not long-term Treasury bond yields. At this time, the application of the CAPM using short-term Treasury yields would not be meaningful because those yields in recent months have approximated zero, and that is expected to continue. It therefore could be argued that the 5 to 8 percent range of Brealy, *et al*. is overstated (probably by 1 to 2 percentage points) if a long-term Treasury yield is used as the risk-free rate.

E. <u>Conclusion on Cost of Equity</u>

Q. WHAT FACTORS DID YOU CONSIDER IN FORMULATING YOUR 10.1 PERCENT COST OF EQUITY RECOMMENDATION?

A. The most important evidence comes from my two DCF studies which produce a range of 9.7 to 10.7 percent and midpoint results of 10.0 percent (gas distribution) and 10.2 percent (electric distribution). The CAPM studies provide somewhat lower cost of equity results, although that method may be somewhat underestimating the utility cost of equity today due to lower than normal Treasury yields. I have also examined the authorized returns for other National Grid companies which average about 10.0 percent. Those authorized returns are of interest because those companies have been able to operate successfully and maintain solid credit ratings with those returns.

There are some additional considerations in interpreting study results.

- I use a six-month average of market data for my DCF studies, and the yield trend has been downward in recent months.

- While it has been my objective to use "pure utility proxies" for Narragansett, that is not possible. Despite my efforts, the proxy companies (on average) have some non-regulated operations, and this added risk may slightly bias upward my *utility* cost of capital measure.

- Unlike Mr. Moul, I did not screen proxy companies based on revenue decoupling regulatory treatment. All else equal, such mechanisms reduce risk. Since some of my proxy companies (e.g., PEPCO, Con Ed) do have such a mechanism, this could slightly understate Narragansett's cost of capital ("all else equal").

With regard to this last factor, I do not believe that my proxy companies are less risky (on average) than Narragansett. The presence of revenue decoupling for some companies is simply one factor among many that affects overall risk. I believe that the first two factors mentioned above (i.e., downward market trends for cost of capital and risky non-regulated operations) are of greater importance in ensuring that by using these 16 proxy companies I have not understated Narragansett's cost of equity.

Q. DOES THIS MEAN THAT YOUR 10.1 PERCENT RECOMMENDATION ASSUMES RDM IS *NOT* ADOPTED?

A. Yes. The 10.1 percent is a reasonable estimate of Narragansett's cost of equity *today* based on the continuation of Rhode Island's current regulatory arrangements. As shown in Section III, credit rating agencies find Rhode Island regulation to be generally "supportive" and a positive factor in their risk evaluations for Narragansett.

If this Commission adopts RDM (in whole or in part) in this case, then it would be appropriate to award a return at least slightly lower than my recommendation.

V. MR. MOUL'S COST OF EQUITY ANALYSES

A. Overview of Mr. Moul's Methods

Q. HOW HAS MR. MOUL DEVELOPED HIS RETURN ON COMMON EQUITY RECOMMENDATION IN THIS CASE?

A. Mr. Moul employs four methods with three of the methods being "market based model approaches to estimating the cost of equity." (Testimony, page 12) The fourth method, "Comparable Earnings," is neither market-based nor is it a method that estimates Narragansett's cost of capital. For that reason, this fourth method is given no weight in Mr. Moul's recommendation in this case. Since Comparable Earnings seems to have little practical importance in this case, I do not devote much time to discussing that method.

The three market-based methods produce the following results: (1) DCF -- 11.17 percent; (2) Risk Premium -- 12.0 percent; and (3) CAPM -- 11.8 percent. Mr. Moul takes the simple average of these three studies (i.e., implicitly assigning equal weight to each) and obtains 11.6 percent. His Comparable Earnings study produces a much higher 14.9 percent. A key point is that Mr. Moul (more or less) bases his studies on a proxy group of "revenue decoupling" utilities. Therefore, he asserts that his cost of equity average result of 11.6 percent is Narragansett's cost of equity if and only if Dr. Tierney's RDM proposal is adopted.

Q. WHAT DOES HE CONTEND IS NARRAGANSETT'S COST OF EQUITY AND FAIR RETURN IF THE RDM IS NOT ADOPTED?

A. His testimony does not address that possibility.

Q. IS MR. MOUL'S APPROACH TO THE RDM REASONABLE?

A. No, unfortunately it is not. While I commend any legitimate attempt to analyze the effect of an RDM on the utility cost of capital, Mr. Moul's approach is misguided.

His mistake is in elevating this one business attribute over all other factors of proxy group risk comparability. He clearly has difficulty in assembling a proxy group, and therefore ends up with only seven companies. Moreover, five of the seven companies are vertically integrated (meaning they build and operate generating plants) and operate on the West Coast or Pacific Northwest. Moreover, in setting his company selection screens, Mr. Moul allows a company to be included even if it has up to 40 percent of operations that are non-utility. At least some of his proxy companies have substantial non-utility operations (including risky merchant power and commodity businesses) which serve to overstate utility risk. For these reasons, his proxy group does not adequately reflect the risk profile of Narragansett, with or without RDM.

Q. IN YOUR OPINION, IS HIS PROXY GROUP RISKIER THAN NARRAGANSETT?

A. Yes, I believe so. While these are generally high quality companies, at least six of the seven are heavily in the electric generation business on either a regulated or unregulated basis. Moreover, the three California companies have large nuclear investments. Electric generation (and particularly unregulated generation) generally is considered riskier than utility distribution service.

Q. MR. MOUL'S SEVEN COMPANIES HAVE SOME FORM OF REVENUE DECOUPLING. DO THEY HAVE REGULATORY PLANS COMPARABLE TO DR. TIERNEY'S RDM PROPOSAL?

A. Mr. Moul does not address this question, but it appears not to be the case or at best is not clear. The RDM designation is somewhat misleading because Dr. Tierney's ambitious proposal covers much more than just revenue decoupling (which companies such as Pepco and Idaho Power have in only a limited or partial way).

Narragansett's proposed RDM also provides for revenue compensation on a formulistic basis for inflation and capital spending. In that respect, Mr. Moul's proxy group does not fully comport with the Company's proposal.

Q. IN SUMMARIZING HIS RESULTS, MR. MOUL STATES THAT HIS 11.6 PERCENT RECOMMENDATION DOES NOT ACCOUNT FOR THE FACT THAT NARRAGANSETT MAY FAIL TO EARN ITS AUTHORIZED RETURN. (PAGE 12) IS THIS ASSERTION CORRECT?

A. No, it is incorrect. I assume that the purpose of this statement is to leave the impression that his 11.6 percent is conservatively low. However, this assertion is wrong because investors fully understand when investing in utility stocks the regulated authorized returns are expectational and not guarantees. Indeed, if that were not the case, then Narragansett would only be entitled only to a risk-free return. My 10.1 percent return recommendation, which is based on actual market data, recognizes that Narragansett's earnings are at risk. However, that risk is modest compared to risks facing unregulated companies.

Q. MR. MOUL FURTHER STATES THAT THE DCF ANALYSIS FAILS TO "CAPTURE VOLATILITY RISK" IN TODAY'S CAPITAL MARKETS. IS THIS STATEMENT CORRECT?

A. No, again he is incorrect. The foundation of the DCF model is the use of actually observed company share prices that result from investor buying and selling activity. Those share prices embody all information available to investors, which includes *all* perceived risks. In order for Mr. Moul's statement to be true, we must believe that investors are not aware of financial market volatility. This assertion is simply not credible.

B. <u>The DCF Model</u>

Q. HOW DOES MR. MOUL OBTAIN HIS 11.17 PERCENT DCF ESTIMATE?

A. Using market data from earlier this year and his RDM proxy group, he calculates an adjusted dividend yield of 5.02 percent. After reviewing an array of growth data from Value Line and other sources, he concludes that investors expect long-run annualized growth for these companies of 6.0 percent. Finally, he adds one more somewhat mysterious factor -- 0.15 percent for "leverage." (I discuss the leverage issue separately in subsection (C) below.) These study elements produce:

$$K_e = 5.02 + 6.0 + 0.15 = 11.17\%$$

I have already expressed my disagreement with his proxy group selection and criteria, and that discussion need not be repeated here.

Q. HOW DID MR. MOUL OBTAIN HIS 6.0 PERCENT DCF GROWTH FACTOR?

A. He examined an array of growth measures both historical and projected, and he clearly favors the projected measures. However, the 6.0 percent figure conclusion does not appear to be the result of any specific calculation. His projected growth factors are listed below (as provided in response to Division 4-16):

Earnings (First Call)	4.96%
Earnings (Zacks)	6.27
Earnings (Value Line)	6.14
Dividends (Value Line)	5.10
Book Value (Value Line)	5.57
Cash Flow (Value Line)	4.29
Earnings Retention (Value Line)	<u>5.86</u>
Average	**5.46%**

These various measures average to 5.46 percent, not 6.0 percent.

Q. DO YOU HAVE ANY FURTHER INFORMATION ON THESE GROWTH MEASURES?

A. Yes. Mr. Moul's figures are from February 2009, and today's growth outlook may be different. I was able to at least update the five Value Line sources of growth, as of August 8, 2009, and I retain his original First Call and Zacks figures, even though they may have changed as well.

	Per Moul	August Update
Earnings (First Call)	4.96%	4.96%*
Earnings (Zacks)	6.27	6.27*
Earnings (Value Line)	6.14	4.07
Dividends (Value Line)	5.10	4.14
Book Value (Value Line)	5.57	5.00
Cash Flow (Value Line)	4.29	3.21
Earnings Retention (Value Line)	5.86	5.00
Average	**5.46%**	**4.66%**

*(Not updated)

The update shows a reduction of almost a full percentage point to 4.66 percent. If Mr. Moul chooses to rely only on those three projected earnings growth measures (which would seems like an overly narrow approach), the measured growth rate would be 5.1 percent. Again, there is no support for his conclusion of a 6.0 percent growth rate.

Q. WHAT DO YOU CONCLUDE?

A. The key to Mr. Moul's DCF result is his assumed growth rate of 6.0 percent. His derivation of this growth rate is vague, and updated information from Value Line casts further doubt on his conclusion. The investor-expected growth rate cannot be 6.0 percent simply because Mr. Moul says so. The available objective evidence instead would support a long-term growth rate perhaps in the 4 to 5 percent range.

Using a 5.0 percent growth rate, and eliminating his erroneous leverage adjustment, his DCF would fall to about 10.0 percent, which is consistent with my recommendation.

C. <u>The Merits of the "Leverage" Adjustment</u>

Q. MR. MOUL INCLUDES AN ADDER TO HIS DCF ESTIMATE FOR "LEVERAGE." WHAT EXPLANATION DOES HE PROVIDE?

A. This is discussed at pages 42-48 of his testimony. Quite simply, Mr. Moul's "leverage" adjustment provides <u>additional</u> return compensation to investors to recognize the fact that standard utility ratemaking employs a utility's book value capital structure instead of a market value capital structure. A company's market value capital structure has a thicker equity ratio than a book value capital structure if that company has a market-to-book ratio greater than 1.0. That is, in fact, the case with most utilities today including Mr. Moul's RDM proxy group. According to Mr. Moul, that group has (on average) a 48.7 percent book equity ratio and a 51.0 percent market equity ratio. Using these data, he calculates the 15 basis point adjustment, as shown in his Appendix NG-PRM-E. While his adjustment is quantitatively small, it must be rejected as fundamentally at odds with cost-based ratemaking.

Q. IS THERE A DIFFERENCE BETWEEN NARRAGANSETT'S MARKET VERSUS BOOK CAPITAL STRUCTURE?

A. No, Narragansett does not have a market-based capital structure because its stock is not publicly traded. It is wholly-owned by National Grid and only has a book capital structure. It has been standard practice in Rhode Island and other states to employ book capital structures (assuming such capital structures are reasonable) for utility ratemaking, just as regulators also use book value rather than market value rate base. No additional shareholder compensation is required simply because either utilities or utility holding companies have market-to-book ratios greater than 1.0. Similarly, if the market-to-book ratio was less than 1.0 (for example, a distressed utility), it would not be proper to decrement the DCF result, thereby reducing shareholder compensation below the DCF return.

Q. IS MR. MOUL'S ADJUSTMENT PART OF THE DCF COST OF EQUITY?

A. No, it is an adder to the DCF cost of equity, unless Mr. Moul is willing to argue that Narragansett has a *higher* cost of equity than his proxy group. (As I have pointed-out, the exact opposite is probably the case.) DCF theory is very clear that the cost of equity can be calculated as "yield plus growth," and this fully accounts for all investment risk including leverage. For example, assume the DCF analysis for the proxy group produces a 10.0 percent result based on a dividend yield of 5.0 percent and a consensus long-run growth rate of 5.0 percent. This result states that investors expect and therefore require (on average) a 10.0 percent long-run annualized return to hold these stocks. In expressing this return requirement, investors are fully aware of the market capital structures of these companies, the book values of these companies *and* the fact that state regulators set rates based on book value capital structure. This knowledge is fully reflected in the stock prices and dividend yields. By their own market behavior, investors are *not* requiring the leverage adjustment that Mr. Moul proposes, although I am sure that they would not mind receiving the additional earnings that his adjustment provides.

Mr. Moul's adjustment is totally contrary to accepted DCF theory as well as regulatory practice.

Q. IS MR. MOUL'S ADJUSTMENT ACCEPTED IN THE REGULATORY COMMUNITY?

A. Mr. Moul asserts that it has been accepted in Pennsylvania, a state commission that relies very heavily on the DCF methodology. He mentions no other jurisdiction adopting this kind of market-to-book adjustment, nor am I aware of any.

Q. IS IT YOUR POSITION THAT A LEVERAGE ADJUSTMENT COULD NEVER BE JUSTIFIED?

A. No, all else equal, debt leverage could be a factor (though not the only factor) in determining a company's cost of equity, and in that context such an adder could be considered (along with other risk attributes). For example, if Narragansett has a more leverage capital structure than the gas proxy group, then potentially, a leverage adjustment could be proposed, consistent with financial theory. The argument here would be that Narragansett is *riskier* than the proxy group (due to its greater leverage), and therefore the 10.0 percent DCF result -- while accurate for the proxy group -- is too low a cost rate for Narragansett. In this case, however, Narragansett is simply *not* more leveraged than the proxy group, and therefore no adjustment is needed.

Moreover, Mr. Moul is not claiming that Narragansett is either more leveraged or more risky than his RDM proxy group. He makes it clear that the issue is one of providing additional compensation to Narragansett investors because the Commission uses a book value capital structure in setting rates. To be clear, Mr. Moul's disagreement is with the practice of cost-based ratemaking and whether that paradigm provides adequate investor compensation.

Q. DOES MR. MOUL CITE ANY EXPERT AUTHORITY FOR A MARKET-TO-BOOK ADJUSTMENT IN THE DCF STUDY?

A. No. Standard financial theory is very clear that, assuming the data inputs are accurate, the DCF model calculates the cost of equity. No further adjustment is needed unless the DCF proxy company group differs in risk from the subject utility -- which is not the case here.

Mr. Moul attempts to cite in connection with his adjustment the seminal work of Miller/Modigliani (of more than 30 years ago) that recognized that a company's leverage could affect its cost of equity. The discussion in my testimony fully recognizes that. However, Mr. Moul, in my opinion takes Miller/Modigliani out of context. Their published work does not address public utility ratemaking practices, including the appropriateness regulators setting rates based on book value capital structure as opposed to market value. To my knowledge, they have expressed no opinion on whether an "adder" to the DCF result is needed due to the normal regulatory practice of using book value capital structure in order to further compensate investors.

It is important to note that Mr. Moul characterizes their work as stating, "as the borrowing of a firm increases, the expected return on stockholders' equity also increases." (Testimony, page 47) To the extent this is true, this is fully captured in a properly performed DCF analysis -- without the need for an extraneous leverage adjustment. That is, investors recognize whatever leverage is present and incorporate it into the "yield plus growth" DCF return result.

Q. DOES MR. MOUL UTILIZE THE LEVERAGE ADJUSTMENT IN ANY OTHER COST OF EQUITY STUDY?

A. Yes. He also includes it in his CAPM study, but he does not appear to use it in his Risk Premium study. Rather than including it as an "adder," his CAPM study uses leverage as a means of increasing the published proxy group beta from its actual value (at that time) of 0.75 to 0.78. This is a small but improper “adder” to his CAPM study.

D. **<u>Risk Premium</u>**

Q. HOW DID MR. MOUL CALCULATE HIS RISK PREMIUM COST OF EQUITY?

A. Mr. Moul calculated the long-term historical returns on the Standard & Poors (S&P) utility index going back to 1928 and compares that to the long-term returns on utility bonds over that same time. He calculates average returns over various historical subperiods and calculates “average” historical returns using at least three different methods. Combining certain results, he finds what he calls a “reasonable” risk premium of 6.23 percentage points. However, he concludes that the S&P utility group is riskier than Narragansett, so he selects a lower risk premium of 5.5 for the Company (i.e., a 73 basis point reduction). Finally, he selects 6.5 percent as a representative current (or expected) yield on single-A utility bonds. The sum of the forecasted 6.5 percent bond yield and a 5.5 percent adjusted Risk Premium produces his Risk Premium cost of equity estimate of 12.0 percent.

Q. HOW DID MR. MOUL CALCULATE THE 73 BASIS POINT DIFFERENCE BETWEEN THE NARRAGANSETT AND S&P INDEX RISK PREMIUM?

A. This is not clear because no calculation is shown for this adjustment. Mr. Moul shows a listing of the S&P utilities on page 3 of his Schedule NG-PRM-4. Only one of the companies in this group is primarily an electric distribution utility. The vast majority are vertically-integrated electric companies, including electrics with extensive unregulated merchant generation operations, such as Constellation, Public

Service Enterprise, PPL Corp., Allegheny Energy, Sempra Energy, Exelon Corp., Entergy Corp., TXU Corp., etc. While some of the members of the S&P group are mainly utilities, the group as a whole is not a very good proxy for Narragansett's electric distribution operations. Mr. Moul recognizes that a significant downward risk adjustment factor is needed.

Q. IS MR. MOUL'S S&P UTILITY INDEX HISTORICAL ANALYSIS AN ACCEPTED METHOD OF ESTIMATING THE COST OF CAPITAL?

A. No, I do not believe this is an accepted method, even for the electric utility/merchant generators that comprise this group. At best, this shows the long-term historical investment experience for this Index, but Mr. Moul does not explain why or how this method reliably estimates today's cost of equity.

It is true that financial analysts sometimes use historical stock market data as a benchmark measure of the risk premium, but the reliability of historical returns as being prospective measures is controversial. However, when such historical returns averages are used by analysts it is almost always for the stock market as a whole (such as the S&P 500), not for an individual company or industry. For example, it is not common practice to use historical returns data for individual industries such as the chemical industry, banking, automobiles, etc. to measure the cost of capital (or risk premia) for those industries.

Q. DOES THE HISTORIC RETURNS DATA USED BY MR. MOUL SUPPORT HIS 12.0 PERCENT COST OF EQUITY RESULT?

A. No. One problem with Mr. Moul's historic returns study is that he fails to update for the large stock market losses that occurred in 2008. Mr. Moul computes the long-term historic (i.e., 1928-2007) risk premium as 5.52 percent using the arithmetic mean measure and 3.74 percent using the geometric return measure.[4] In response to Division 4-26, he reports that for 2008 utility stocks experienced a *negative* return of 28.96 percent, whereas corporate bonds experienced a market return of 8.78 percent. (He was not able to report on utility bonds for 2008.) Incorporating 2008 data into the long-term historic average reduces the arithmetic risk premium to 5.02 percent and the geometric risk premium to 2.46 percent.

Applying Mr. Moul's adjustment for Narragansett's lower risk (i.e., his 88 percent factor) and including the current single-A bond yield of 6.0 percent[5] produces in the following results:

Arithmetic Mean: 5.02% x 88% + 6.0% = 10.4%

Geometric Mean: 2.46% x 88% + 6.0% = 8.16%

The updated Risk Premium analysis produces a cost of equity range of 8.2 to 10.4 percent. Mr. Moul's 12.0 percent result is clearly incorrect since it ignores the large stock market losses that occurred in 2008.

As a further check, I calculated the market returns for the last quarter century, i.e., 1984 – 2008, using the data series on Mr. Moul's Schedule NG-PRM-9 and the response to Division 4-26 (i.e., the 2008 data). This time period produced an equity risk premium (arithmetic mean) of 4.08 percent. Again, using Mr. Moul's formula, the risk premium-derived cost of equity becomes:

4.08% x 88% + 6.0% = 9.59%

Q. WHAT DO YOU CONCLUDE CONCERNING THE RISK PREMIUM ANALYSIS?

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[4] Mr. Moul also presents one additional measure, the median. However, the median is *not* an accepted measure of historic long-run market returns or the historic risk premium. His median values should be disregarded as irrelevant to a historical returns analysis.

[5] Mr. Moul used a projected 6.5 percent, single-A utility bond cost rate, but the actual is currently about 6.0 percent.

A. Mr. Moul's 12.0 percent risk premium cost of equity is not supported by his own data, particularly when updated to include the large negative equity premium experienced in 2008. While a corrected and updated analysis would support my 9.7 to 10.7 percent DCF range, the Commission should place no reliance on this method.

E. CAPM Study

Q. HOW DID MR. MOUL DERIVE HIS CAPM ESTIMATE?

A. Mr. Moul begins with the standard CAPM adopting a proxy group beta of 0.75 (obtained from Value Line), a prospective cost of long-term Treasury debt of 4.0 percent and a stock market risk premium of 8.8 percent. In addition, he adds two discrete adjustments, both of which improperly inflate his CAPM final result:

- A leverage adjustment that increases the proxy group beta (published by Value Line) from 0.75 to 0.78 (as discussed earlier); and
- A "size" adjustment that adds 0.94 percent (94 basis points) to the final result.

These inputs and adjustments produce his 11.8 percent cost of equity:

$$K_e = 4.0\% + 0.78(8.8) + 0.94 = 11.8\%$$

Q. WHAT WOULD HIS RESULT BE WITHOUT THESE TWO IMPROPER ADJUSTMENTS?

A. If the two adjustments were removed, his cost of equity estimate would be:

$$K_e = 4.0\% + 0.75(8.8) = 10.6\%$$

Q. WHAT ARE YOUR CONCERNS WITH MR. MOUL'S CAPM ANALYSIS?

A. There are several flaws in Mr. Moul's analysis that lead him to seriously overstate his cost of equity estimate using this model. I already have discussed two of these problems in connection with his DCF study, namely, his proxy group of mostly vertically-integrated (and partially deregulated) electric companies, and his improper "leverage" adjustment. The latter adjustment leads Mr. Moul to improperly increase the Value Line proxy group betas from 0.75 to 0.78. Please note that more recent Value Line reports show a decline for this group average beta to 0.72, which is very close to the 0.7 figure that I used in my CAPM study.

There are two other very large errors in his study. The first and most serious error is his inclusion of a 0.94 percent ROE "adder" for Narragansett's allegedly small size. His second error is his selection of an overall stock market risk premium of 8.8 percent, a figure that cannot be supported by any careful, objective analysis. It exceeds the Brealey, et al. upper bound figure of 8 percent.

Q. WHAT ANALYSIS DOES MR. MOUL PROVIDE IN SUPPORT OF HIS SIZE ADJUSTMENT OF 0.94 PERCENT?

A. Other than noting that Narragansett is smaller, on average, than his proxy companies (such as PG&E Corp. and Consolidated Edison), he performs no analysis of his own to estimate how size may affect the cost of equity. Instead, he cites to evidence from a short article published in *Public Utilities Fortnightly*.

Q. DOES THE EVIDENCE CITED BY MR. MOUL SUPPORT A RISK ADJUSTMENT?

A. No, it does not, for several reasons. First, an assertion of a size risk factor contradicts modern portfolio theory. Specifically, small companies can be combined by investors into portfolios in order to eliminate risk that is purely due to size. Second, the empirically observed "small stock volatility," which is simplistically interpreted as "small size risk," may not due to size *per se* but rather to the maturity of the firm, i.e., where the firm is in its life cycle. For example, a biotech start-up firm is likely to be viewed as riskier than a large, mature pharmaceutical company. However, it obviously would be erroneous to attribute this greater risk to the biotech's size. In other words, the statistically-observed size premium may be spurious.

The key point is that the size risk premium – if it exists at all – may have little to do with pure utility companies. Mr. Moul presents no evidence that a *utility* with, for example, a $3 billion capitalization is any riskier (all else equal) than an $8 billion utility. He cites to no studies in that regard that specifically focus on utilities.

Q. IF THERE IS SUCH A THING AS A "SIZE PREMIUM", WOULD IT APPLY IN THIS CASE TO NARRAGANSETT'S COST OF EQUITY?

A. No. While there is no conceptual basis for including size as a variable in the CAPM, even if there were, it would not apply to Narragansett. This is because Narragansett is a component of National Grid USA, which owns all of Narragansett's equity and is the source of all of its equity. Narragansett is fully financially integrated with National Grid USA, which is a giant utility. As of 2008, National Grid USA had a total book capitalization of approximately $22 billion. Hence, as a factual matter, there can be no basis whatsoever for a "size adder" to the CAPM cost of equity. Mr. Moul erred in failing to understand that Narragansett is part of National Grid USA. Even if there were such thing as a "small size adder," Mr. Moul's adjustment erroneously treats Narragansett as a stand-alone, public company.

Q. IS THERE ANY OTHER REASON TO QUESTION THIS ADDER?

A. Yes. If Mr. Moul believes that size is an important determinant of cost of equity for a utility, then he should have used size as a proxy company selection criterion. Inexplicably, he did not.

Q. HOW DID HE OBTAIN HIS 8.8 PERCENT RISK PREMIUM?

A. Mr. Moul cites to three measures of the market risk premium. Two are relatively conventional, but the third is unquestionably wrong. The two conventional measures include (a) the use of historical S&P 500 market returns data prepared by Ibbotson, and (b) a DCF calculation of the S&P 500. Most analysts would acknowledge that the S&P 500 provides a reasonable (though not perfect) representation of the U.S. stock market. The historic returns – derived risk premium, relative to long-term Treasury securities, is 6.1 percent. Mr. Moul's S&P 500 DCF analysis employs a dividend yield of 4.17 percent and a projected earnings growth rate of 9.49 percent, as follows:

$$\text{S\&P 500 } K_e = 4.17\% \, (1.045) + 9.49\% = 13.8\%$$

With a Treasury yield of 4 percent, this produces a risk premium of 9.8 percent.

Please note that since Mr. Moul prepared his testimony, the dividend yield on the S&P 500 has declined. This appears to be due both to dividend cuts by some S&P 500 companies and a major upward movement in this index in recent months. It is now about 2.5 percent. Using this updated yield with his 9.49 percent growth rate would produce a DCF total return of about 12 percent, not 13.8 percent. With the 4.0 percent Treasury yield, the risk premium would decline from his 9.8 percent to about 8.0 percent.

In summary, Mr. Moul's two conventional measures produce a risk premium range of about 6 to 8 percent, or an average of about 7 percent. This is fully consistent with my 5 to 8 percent range discussed in Section IV of my testimony.

Q. DO YOU FULLY ACCEPT THE UPDATED S&P 500 DCF CALCULATION?

A. No, I do not. While far more realistic than Mr. Moul's 13.8 percent, the updated 12.0 percent estimate is probably somewhat too high. This is because it is based on a 9.49 percent earnings growth rate which likely incorporates recovery from an economic recession. The March 10, 2009 edition of *Blue Chip Economic Indicators* (a compilation of major forecasting organizations) includes a forecast of U. S. corporate profits. The Blue Chip "consensus" shows the growth rate to be 7.0 percent from 2011 to 2015 (as the U. S. economy recovers), but the 2016 to 2020 growth rate diminishes to 5.5 percent per year. This suggests that the 9.49 percent S&P 500 earnings growth rate that Mr. Moul cites probably exceeds the long-run sustainable growth rate that the DCF model requires. This means that even updated 8.0 percent risk premium is probably too high since it is derived from a 9.49 percent earnings growth rate.

Q. WHAT IS MR. MOUL'S UNCONVENTIONAL MEASURE?

A. His third measure uses data published by Value Line referred to as the stock price "Appreciation Potential." This is a figure published by Value Line that purportedly represents the amount by which the median stock in Value Line's 1,700-company data base might appreciate in price over the next 3 to 5 years. Mr. Moul uses these data to calculate an annualized return of 17.2 percent, providing a risk premium value of 13.2 percent. This is clearly an outlandish result that cannot be found anywhere in the professional risk premium literature.

Q. WHY IS THIS MEASURE INCORRECT?

A. The risk premium used in the CAPM must be based upon some reasonable measure of the overall stock market, and the S&P 500 studies reasonably comply with that requirement. Mr. Moul's Value Line calculation for the "median company," however, makes no attempt to meet that requirement. At best, it is an attempt to measure a "potential return" for the median Value Line stock, but it is *not* a measure of even the "potential" stock market return. This is a fatally-flawed procedure and has no place in a valid CAPM analysis.

Q. WHAT IS THE RESULT FROM CORRECTING MR. MOUL'S CAPM?

A. Using the updated and corrected 7 percent risk premium and removing the "size adder" we obtain:

$$K_e = 4.0\% \ 0.75\ (7.0\%) = 9.25\%$$

F. **Comparable Earnings**

Q. HOW DID MR. MOUL CONDUCT HIS COMPARABLES EARNINGS STUDY?

A. Mr. Moul selected a group of unregulated companies that appear to have relatively stable operating profiles. He compiled both their historical earned returns on equity and their projected equity returns. On a historical basis, their earned returns average 15.5 percent, and on a projected basis they average 14.3 percent. The average of the two measures is 14.9 percent.

Q. IS THIS A COST OF EQUITY METHOD?

A. No, it is not. These are pure accounting results and no market data is employed in the analysis. As a result, Mr. Moul disregards this information in deriving his 11.6 percent return on equity recommendation, and he acknowledges that it is not a market-based cost method.

Q. DO THESE ACCOUNTING FIGURES TELL US ANYTHING ABOUT INVESTOR RETURN REQUIREMENTS?

A. No. The main problem is that these stocks normally sell at large premiums to their book values. While a given non-regulated company might have an accounting return on equity of 20 percent, if its shares are selling at two to three times book value per share, investors purchasing the stock at that price very likely expect to realize (and therefore require) market returns much lower than that 20 percent. It is for this reason that the accounting ROEs are of little interest to investors, and this measure is irrelevant to the "capital attraction" standard. Investors tend to focus far more on the relationship of earnings to the market price of the stock.

Q. ARE THERE OTHER MEASUREMENT OR CONCEPTUAL PROBLEMS WITH THE COMPARABLE EARNINGS METHOD, AS USED BY MR. MOUL?

A. Yes, there are other problems. The measurement of accounting returns on equity for non-regulated firms frequently is distorted by accounting write offs. These write offs would be reflected as reductions to the equity balance, thereby inflating the reported accounting ROE. For example, if company has $15 of earnings and $150 of equity, the ROE is 10 percent. If the company subsequently takes a $50 accounting write-off, the calculated ROE then becomes $15/$100 = 15%. These accounting write-offs that inflate the measured rate of return are common and often very large for unregulated companies, but have nothing to do with Narragansett's regulated return requirement.

A conceptual problem with the Comparable Earnings method is that the earnings reported by Mr. Moul (i.e., the numerator of the reported ROEs) can be strongly influenced by the exercise of market or monopoly power. This refers to profits earned by successful companies due to certain favorable circumstances that exceed the competitive level of profits. Such monopoly profits could be attributable to circumstances that are entirely legal such as patent protection, unusually favorable access to key resources or a company's unique product line offering. Mr. Moul has conducted no analysis to determine whether or not the profitability results that he cites in his Comparable Earnings study are from markets deemed to be fully competitive. Profits associated with market power cannot be used as a standard for either setting or evaluating Narragansett's fair return.

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

Mr. Kahal is currently an independent consulting economist, specializing in energy economics, public utility regulation and financial analysis. Over the past two decades, his work has encompassed electric utility integrated resource planning (IRP), power plant licensing and a wide range of utility financial issues. In the financial area he has conducted numerous cost of capital studies and addressed other financial issues for electric, gas, telephone and water utilities. Mr. Kahal's work in recent years has shifted to electric utility restructuring, mergers and competition.

Mr. Kahal has provided expert testimony on more than 300 occasions before state and federal regulatory commissions and the U.S. Congress. His testimony has covered need for power, integrated resource planning, cost of capital, purchased power practices and contracts, merger economics, industry restructuring and various other regulatory policy issues.

Education:

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

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

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

Previous Employment:

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

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

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

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

1975-1977 - Lecturer in Business/Economics, Montgomery College.

Professional Work Experience:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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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

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

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

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

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

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

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

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

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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

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

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

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

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

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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
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	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

BEFORE THE

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

PUBLIC UTILITIES COMMISSION

RE: THE NARRAGANSETT ELECTRIC COMPANY: INVESTIGATION AS TO THE PROPRIETY OF PROPOSED TARIFF CHARGES	**))))**	**DOCKET NO. 4065**

SCHEDULES ACCOMPANYING THE
DIRECT TESTIMONY OF
MATTHEW I. KAHAL

ON BEHALF OF THE

DIVISION OF PUBLIC UTILITIES AND CARRIERS

SEPTEMBER 15, 2009

NARRAGANSETT ELECTRIC COMPANY

Provisional Rate of Return Summary

Capital Type	% of Total[(1)]	Cost Rate	Weighted Cost
Long-Term Debt	47.33%	6.10%[(2)]	2.89%
Preferred Stock	0.19	4.50	0.01
Short-Term Debt	4.98	1.60[(3)]	0.08
Common Equity	47.50	10.10[(4)]	4.80
Total	100.00%	--	7.78%

[1] Source: Based on Schedule NG-PRM-1 for preferred stock and long-term debt. Common equity is reduced from 50.0 to 47.5 percent on a provisional basis. See testimony for discussion.

[2] Company estimate, but reduced to reflect more current cost of single-A utility debt.

[3] Estimate based on most recent 12-month average. See page 2 of this Schedule.

[4] Source: Schedules MIK-4 and MIK-5 and testimony.

NARRAGANSETT ELECTRIC COMPANY

Short-Term Debt Balances and Cost Rates
July 2008 – June 2009
(Thousands $)

	Balance	Interest Rate
July 2008	$99,500	2.45%
August	134,525	2.44
September	75,800	3.47
October	98,375	4.52
November	147,475	1.88
December	119,400	1.18
January 2009	122,075	0.57
February	124,800	0.76
March	129,625	0.69
April	126,825	0.48
May	131,600	0.38
June	137,925	0.35
Average	**$120,660**	**1.60%***

Source: Response to Division 4.

* The average is 1.12 percent excluding the cost rates of September and October which reflect crisis conditions.

NARRAGANSETT ELECTRIC COMPANY

U.S. Historic Trends in Capital Costs

	Annualized Inflation (CPI)	10-Year Treasury Yield	3-Month Treasury Yield	Single-A Utility Yield
1992	3.0%	7.0%	3.5%	8.7%
1993	3.0	5.9	3.0	7.6
1994	2.6	7.1	4.3	8.3
1995	2.8	6.6	5.5	7.9
1996	3.0	6.4	5.0	7.8
1997	2.3	6.4	5.1	7.6
1998	1.6	5.3	4.8	7.0
1999	2.2	5.7	4.7	7.6
2000	3.4	6.0	5.9	8.2
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

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
2002				
January	1.1%	5.0%	1.7%	7.7%
February	1.1	4.9	1.7	7.5
March	1.5	5.3	1.8	7.8
April	1.6	5.2	1.7	7.6
May	1.2	5.2	1.7	7.5
June	1.1	4.9	1.7	7.4
July	1.5	4.7	1.7	7.3
August	1.8	4.3	1.6	7.2
September	1.5	3.9	1.6	7.1
October	2.0	3.9	1.6	7.2
November	2.2	4.1	1.3	7.1
December	2.4	4.0	1.2	7.1
2003				
January	2.6%	4.1%	1.2%	7.1%
February	3.0	3.9	1.2	6.9
March	3.0	3.8	1.1	6.8
April	2.1	4.0	1.1	6.6
May	2.1	3.6	1.1	6.4
June	2.1	3.7	0.9	6.2
July	2.1	4.0	0.9	6.6
August	2.2	4.5	1.0	6.8
September	2.3	4.3	1.0	6.6
October	2.0	4.3	0.9	6.4
November	1.8	4.3	1.0	6.4
December	1.8	4.3	0.9	6.3
2004				
January	1.9%	4.2%	0.9%	6.2%
February	1.7	4.1	0.9	6.2
March	1.7	3.8	0.9	6.0
April	2.3	4.4	0.9	6.4
May	3.1	4.7	1.0	6.6
June	3.3	4.7	1.3	6.5
July	3.0	4.5	1.4	6.3
August	2.7	4.3	1.5	6.1
September	2.5	4.1	1.6	6.0
October	3.2	4.1	1.8	5.9
November	3.5	4.2	2.1	6.0
December	3.3	4.2	2.2	5.9

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
2005				
January	3.0%	4.2%	2.4%	5.8%
February	3.0	4.2	2.6	5.6
March	3.1	4.5	2.8	5.8
April	3.5	4.3	2.8	5.6
May	2.8	4.1	2.9	5.5
June	2.5	4.0	3.0	5.4
July	3.2	4.2	3.3	5.5
August	3.6	4.3	3.5	5.5
September.	4.7	4.2	3.5	5.5
October	4.3	4.5	3.8	5.8
November	3.5	4.5	4.0	5.9
December	3.4	4.5	4.0	5.8
2006				
January	4.0%	4.4%	4.3%	5.8%
February	3.6	4.6	4.5	5.8
March	3.4	4.7	4.6	6.0
April	3.5	5.0	4.7	6.3
May	4.2	5.1	4.8	6.4
June	4.3	5.1	4.9	6.4
July	4.1	5.1	5.1	6.4
August	3.8	4.9	5.1	6.2
September	2.1	4.7	4.9	6.0
October	3.5	4.7	5.1	6.0
November	2.5	4.6	5.1	5.8
December	2.5	4.6	5.0	5.8

NARRAGANSETT ELECTRIC COMPANY

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

	Annualized Inflation (CPI)	10-Year Treasury Yield	3-Month Treasury Yield	Single-A Utility Yield
2007				
January	2.1%	4.8%	5.1%	6.0%
February	2.4	4.7	5.2	5.9
March	2.8	4.6	5.1	5.9
April	2.6	4.7	5.0	6.0
May	2.7	4.8	5.0	6.0
June	2.7	5.1	5.0	6.3
July	2.4	5.0	5.0	6.3
August	2.0	4.7	4.3	6.2
September	2.8	4.5	4.0	6.2
October	3.5	4.5	4.0	6.1
November	4.3	4.2	3.4	6.0
December	4.1	4.1	3.1	6.2
2008				
January	4.3%	3.7%	2.8%	6.0%
February	4.0	3.7	2.2	6.2
March	4.0	3.5	1.3	6.2
April	3.9	3.7	1.3	6.3
May	4.2	3.9	1.8	6.3
June	5.0	4.1	1.9	6.4
July	5.6	4.0	1.7	6.4
August	5.4	3.9	1.8	6.4
September	4.9	3.7	1.2	6.5
October	3.7	3.8	0.7	7.6
November	1.1	3.5	0.2	7.6
December	0.1	2.4	0.0	6.5
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	--	3.6	0.2	6.0 (P)

Sources: *Economic Report of the President, Mergent's Bond Record, Federal Reserve Statistical Release, Consumer Price Index Summary*

NARRAGANSETT ELECTRIC COMPANY

Listing of the Gas Utility Proxy Companies

	Company	Safety Rating	Financial Strength	Beta	2008 Common Equity Ratio*
1.	AGL Resources	2	B++	0.75	49.7%
2.	Atmos Energy	2	B+	0.65	49.2
3.	LaClede Group	2	B+	0.60	55.5
4.	Nicor, Inc.	3	A	0.75	68.4
5.	NW Natural Gas	1	A	0.60	55.1
6.	Piedmont Natural	2	B++	0.65	52.8
7.	South Jersey Ind.	2	B++	0.65	60.8
8.	Southwest Gas	3	B	0.75	44.7
9.	WGL Corp.	1	A	0.65	62.4
	Average	**1.9**	**--**	**0.67**	**55.4%**

* The common equity ratio reported by Value Line excludes short-term debt (and current maturities of long-term debt).

Source: *Value Line Investment Survey*, June 12, 2009

NARRAGANSETT ELECTRIC COMPANY

Listing of the Electric Utility Distribution Proxy Companies

Company	Safety Rating	Financial Strength	Beta	2008 Common Equity Ratio*
1. CH Energy Group	1	A	0.65	54.6%
2. Central Vt. Public Service	3	B	0.80	55.4
3. Consolidated Ed.	1	A+	0.65	51.2
4. Northeast Utilities	3	B+	0.70	38.1
5. NSTAR	1	A	0.65	42.8
6. PEPCO Holdings, Inc.	3	B	0.80	43.8
7. UIL Holdings	2	B++	0.70	46.4
Average	**2.0**	**--**	**0.71**	**47.5%**

* The common equity ratio reported by Value Line excludes short-term debt (and current maturities of long-term debt).

Source: *Value Line Investment Survey*, August 28, 2009

NARRAGANSETT ELECTRIC COMPANY

DCF Summary for
Gas Distribution Proxy Group

1. Dividend Yield (March– August 2009)	4.57%[1]
2. Adjusted Yield ((1) x 1.0275)	4.7%
3. Long-Term Growth Rate	5.0 - 5.5[2]
4. Total Return ((2) + (3))	9.7 - 10.2%
5. Flotation Adjustment	0.00%
6. Cost of Equity ((4) + (5))	9.7 - 10.2%
7. Midpoint	10.0%
Recommendation	**10.1%**

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

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

NARRAGANSETT ELECTRIC COMPANY

Dividend Yields for Gas Distribution Proxy Group
(March – August 2009)

	Company	March	April	May	June	July	August	Average
1.	AGL Resources	6.5%	5.5%	5.9%	5.4%	5.1%	5.0%	5.57%
2.	Atmos	5.7	5.3	5.5	5.3	4.9	4.8	5.25
3.	LaClede	4.0	4.4	5.0	4.6	4.6	4.6	4.53
4.	NICOR	5.6	5.8	5.9	5.4	5.1	5.0	5.47
5.	Northwest Nat.	3.6	3.9	3.7	3.6	3.5	3.7	3.67
6.	Piedmont	4.2	4.4	4.8	4.5	4.4	4.3	4.43
7.	South Jersey	3.4	3.4	3.6	3.4	3.2	3.3	3.38
8.	Southwest Gas	4.5	4.7	4.6	4.3	3.9	3.8	4.30
9.	WGL	4.5	4.7	4.9	4.6	4.4	4.3	4.57
	Average	**4.67%**	**4.68%**	**4.90%**	**4.58%**	**4.34%**	**4.31%**	**4.57%**

Source: S&P *Stock Guide*, April – August 2009. The August yields are approximately month ending reported by Yahoo Finance since the September edition of S&P *Stock Guide* is not yet available.

NARRAGANSETT ELECTRIC COMPANY

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

	Company	Value Line	First Call	Zacks	CNN	Average
1.	AGL Resources	3.5%	4.5%	5.3%	5%	4.58%
2.	Atmos	4.0	5.0	5.0	5	4.75
3.	LaClede	3.5	3.5	3.0	3	3.25
4.	NICOR	0.5	4.3	4.2	4	3.25
5.	Northwest	5.0	5.2	6.8	6	5.75
6.	Piedmont	6.0	6.2	6.7	8	6.72
7.	South Jersey	5.5	9.6	9.5	8	8.15
8.	Southwest	5.0	5.7	6.0	6	5.68
9.	WGL	4.0	4.5	6.7	5	5.05
	Average	**4.11%**	**5.39%**	**5.90%**	**5.56%**	**5.24%**

Sources: *Value Line Investment Survey*, June 12, 2009. First Call is from Yahoo Finance website (August 2009) and Zacks is from MSN Money website (August 2009). In addition, the CNN figures are from the CNNfn web site (August 2009).

NARRAGANSETT ELECTRIC COMPANY

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

	Company	Dividend Per Share	Book Value Per Share	Earnings Retention
1.	AGL Resources	2.5%	1.5%	6.0%
2.	Atmos	1.5	4.0	4.0
3.	LaClede	2.5	5.5	5.0
4.	NICOR	0.0	4.5	4.0
5.	Northwest	5.5	5.0	4.5
6.	Piedmont	3.5	4.0	5.0
7.	South Jersey	7.0	6.0	6.5
8.	Southwest	5.0	3.5	4.0
9.	WGL	2.5	5.0	4.5
	Average	**3.33%**	**4.33%**	**4.83%**

Source: *Value Line Investment Survey*, June 12, 2009. The earnings retention figures are projections for 2012-2014.

NARRAGANSETT ELECTRIC COMPANY

DCF Summary for
Electric Distribution Utility Proxy Group

1. Dividend Yield (March – August 2009)	5.81%[(1)]
2. Adjusted Yield ((1) x 1.022)	5.9%
3. Long-Term Growth Rate	3.8 - 4.8[(2)]
4. Total Return ((2) + (3))	9.7 - 10.7%
5. Flotation Adjustment	0.00%
6. Cost of Equity ((4) + (5))	9.7 - 10.7%
7. Midpoint	10.02%
Recommendation	**10.1%**

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

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

NARRAGANSETT ELECTRIC COMPANY

Dividend Yields for Electric Distribution Utility Proxy Group
(March-August 2009)

	Company	March	April	May	June	July	August	Average
1.	CH Energy	4.6%	4.9%	5.2%	4.6%	4.4%	4.6%	4.72%
2.	Central Vt.	5.3	5.4	5.7	5.1	5.0	4.9	5.23
3.	Consolidated Ed.	6.0	6.4	6.7	6.3	6.0	5.8	6.20
4.	Northeast Utilities	4.4	4.5	4.6	4.3	4.1	4.0	4.32
5.	NSTAR	4.7	4.8	5.0	4.7	4.7	4.7	4.77
6.	Pepco Holdings, Inc.	8.7	8.0	8.3	8.0	7.5	7.4	7.98
7.	UIL Holdings	7.7	7.5	8.3	7.7	7.1	6.6	7.48
	Average	**5.91%**	**5.93%**	**6.26%**	**5.81%**	**5.54%**	**5.43%**	**5.81%**

Source: S&P *Stock Guide*, April -- August 2009. August dividend yield is month ending from YahooFinance.com since the September S&P *Stock Guide* is not yet available.

NARRAGANSETT ELECTRIC COMPANY

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

	Company	Value Line	First Call	Zacks	CNN	Average
1.	CH Energy	3.0%	NA	NA	NA	3.00%
2.	Central Vt.	3.0	8.9%	NA	NA	5.95
3.	Consolidated Ed.	3.0	3.4	3.8%	2%	3.05
4.	Northeast Utilities	8.0	8.5	7.7	8	8.05
5.	NSTAR	8.0	5.5	5.7	6	6.30
6.	Pepco Holdings, Inc.	2.0	5.5	5.0	3	3.88
7.	UIL Holdings	3.0	4.4	4.1	4	3.88
	Average	**4.29%**	**6.03%**	**5.26%**	**4.60%**	**4.87%**

Sources: *Value Line Investment Survey*, August 28, 2009. First Call is from Yahoo Finance website (August 2009) and Zacks is from MSN Money website (August 2009). In addition, the CNN figures are from the CNNfn web site (August 2009).

NARRAGANSETT ELECTRIC COMPANY

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

	Company	Dividend Per Share	Book Value Per Share	Earnings Retention
1.	CH Energy	0.0%	1.5%	2.0%
2.	Central Vt.	0.0	6.5	3.5
3.	Consolidated Ed.	1.0	3.5	3.5
4.	Northeast Utilities	6.5	5.0	4.0
5.	NSTAR	5.5	5.5	6.0
6.	Pepco Holdings, Inc.	0.0	2.0	3.0
7.	UIL Holdings	0.0	2.5	2.5
	Average	**1.86%**	**3.79%**	**3.50%**

Source: *Value Line Investment Survey*, August 28, 2009. The earnings retention figures are projections for 2012-2014.

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 = 4.0% (Treasury long-term bond yields for the most recent six months, see page 2 of 3)

Rm = 9.0 – 12.0% (equates to an equity risk premium of 5.0 - 8.0%)

Beta = 0.7 (Source: page 3 of this schedule)

C. Model Calculations

Low end:	K_e = 4.0% + 0.7 (5.0) = 7.50%
Midpoint:	K_e = 4.0% + 0.7 (6.5) = 8.55%
Upper End:	K_e = 4.0% + 0.7 (8.0) = 9.60%

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Long-Term Treasury Yields
(February – July 2009)

	10-Year	20-Year	30-Year
February 2009	2.9%	3.8%	3.6%
March	2.8	3.8	3.6
April	2.9	3.8	3.8
May	3.3	4.2	4.2
June	3.7	4.5	4.5
July	3.6	4.4	4.4
Average	**3.2%**	**4.1%**	**4.0%**

Source: Federal Reserve *Statistical Release* (H.15), various issues.

NARRAGANSETT ELECTRIC COMPANY

Beta Statistics for Proxy Companies

Gas Distribution Utilities

Company	Value Line	Yahoo Finance	MSN Money	Average
1. AGL Resources	0.75	0.42	0.42	0.53
2. Atmos	0.60	0.51	0.52	0.54
3. LaClede	0.65	-0.10	0.04	0.20
4. NICOR	0.75	0.34	0.35	0.48
5. Northwest Natural	0.60	0.24	0.27	0.37
6. Piedmont	0.65	0.15	0.20	0.33
7. South Jersey	0.65	0.21	0.22	0.36
8. Southwest Gas	0.70	0.73	0.70	0.71
9. WGL	0.65	0.16	0.21	0.34
Average	**0.67**	**0.30**	**0.33**	**0.44**

Electric Distribution Utilities

Company	Value Line	Yahoo Finance	MSN Money	Average
1. CH Energy	0.65	0.40	0.42	0.49
2. Central Vt.	0.80	0.57	0.68	0.68
3. Consolidated Ed.	0.65	0.25	0.27	0.39
4. Northeast Utilities	0.70	0.48	0.50	0.56
5. NSTAR	0.65	0.22	0.25	0.37
6. Pepco Holdings, Inc.	0.80	0.55	0.56	0.64
7. UIL Holdings	0.70	0.73	0.73	0.72
Average	**0.71**	**0.46**	**0.49**	**0.55**

Sources: *Value Line Investment* Survey, August 28, June 12, 2009.
MSN Money and Yahoo Finance, August 2009.