STATE OF NEW JERSEY
OFFICE OF ADMINISTRATIVE LAW
BEFORE THE HONORABLE RICHARD MCGILL, ALJ

	)	
I/M/O THE VERIFIED PETITION OF	)	
ROCKLAND ELECTRIC COMPANY	)	
FOR APPROVAL OF CHANGES IN	)	**BPU DOCKET No. ER09080668**
ELECTRIC RATES, ITS TARIFF FOR	)	**OAL DOCKET No. PUC-11407-2009N**
ELECTRIC SERVICES, ITS	)	
DEPRECIATION RATES, AND OTHER	)	
RELIEF	)	

DIRECT TESTIMONY OF MATTHEW I. KAHAL ON BEHALF OF THE NEW JERSEY DEPARTMENT OF THE PUBLIC ADVOCATE, DIVISION OF RATE COUNSEL

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APPENDIX A

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 the Rate Counsel (Rate Counsel). 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 25 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 and federal court in more than 350 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, the Maine Public Advocate, Maryland Department of Natural Resources and Energy Administration, and MCI.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE NEW JERSEY BOARD OF PUBLIC UTILITIES?

A. Yes. I have testified on cost of capital and other matters before the Board of Public Utilities (Board or BPU) in gas, water and electric cases during the past 20 years. A listing of those cases is provided in my attached Statement of Qualifications. This includes the submission of testimony on rate of return issues in the recent electric and gas service rate case of New Jersey Natural Gas Company (BPU Docket No. GR070110889), Elizabethtown Gas (BPU Docket No. GR09030195) and Public Service Electric and Gas Company (BPU Docket Nos. GR05100845 and GR09050422). In addition, I testified in Rockland Electric Company's last base rate case in 2006/2007 (Docket No. ER06060483).

II. OVERVIEW

A. Summary of Recommendation

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

A. I have been asked by the Division of Rate Counsel ("Rate Counsel") to develop a recommendation concerning the fair rate of return on the electric distribution utility rate base of Rockland Electric Company ("RECO" 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 Rate Counsel and its consultants for use in calculating the test year annual revenue requirement in this case.

RECO is not an independent company, nor is it publically traded. It is wholly-owned by Orange and Rockland Utilities, Inc. ("O&R") which, in turn, is owned by Consolidated Edison, Inc., one of the nation's largest delivery service ("wires and pipes") utilities.

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

A. The Company's overall rate of return, capital structure and debt costs are sponsored by RECO witness Perkins. His recently-filed 12 + 0 update produces a requested return on rate base of 8.57 percent, as shown in Table 1 below.

Table 1 RECO Proposed Rate of Return – 12 + 0 Update			
Capital Type	% Total	Cost Rate	Weighted Cost
Long-Term Debt	49.87%	6.16%	3.07%
Short-Term Debt	0.17	2.50	0.00
Common Equity	49.96	11.00	5.50
Total	**100%**	--	**8.57%**

The 11.0 percent return on equity ("ROE") request is sponsored by RECO's outside consultant, Dr. Roger Morin. The capital structure/cost of debt is based on the actual capital structure of the consolidated O&R (with certain adjustments) at December 31, 2009. It should be noted that the 12 + 0 update rate of return of 8.57 percent is lower than the originally-filed request of 8.77 percent. The original request incorporated a 54 percent equity/46 percent debt capital structure and excluded short-term debt.

Q. HOW DOES THE UPDATED REQUEST OF 8.57 PERCENT COMPARE TO RECO'S CURRENTLY-AUTHORIZED RATE OF RETURN?

A. RECO's currently-authorized rate of return was set by the Board in 2007 in Docket No. ER06060483, as shown below in Table 2:

Table 2 RECO Currently-Authorized Rate of Return			
Capital Type	% Total	Cost Rate	Weighted Cost
Long-Term Debt	49.197%	6.26%	3.08%
Short-Term Debt	4.30	5.00	0.22
Common Equity	46.51	9.75	4.53
Total	**100%**	--	**7.83%**

Even with the reduction in the 12 + 0 update, the Company in this case is seeking a substantial increase in its authorized return, which is a major reason for its rate request. The ROE goes from 9.75 to 11.0 percent (a 13 percent increase) and the common equity ratio increases from 46.5 percent to 50.0 percent (a 7.5 percent increase). As my testimony explains, RECO is seeking these large return increases even though its cost of capital remains quite low and its business risk profile continues to be favorable.

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

A. As summarized on page 1 of Schedule MIK-1, I am recommending an authorized overall rate of return of 8.12 percent, subject to updating. This includes a return on common equity of 10.1 percent, and a capital structure of 49.9 percent long-term debt, 0.4 percent short-term debt and 49.8 percent common equity. It should be noted that I am recommending both a return on equity and common equity ratio that are somewhat higher than currently authorized.

Q. DO YOU ACCEPT RECO'S GENERAL APPROACH TO CAPITAL STRUCTURE?

A. Yes. Under the circumstances, it is reasonable to use the actual O&R consolidated capitalization for the rate setting capital structure, consistent with past practice for RECO. My recommended capital structure and that of the Company in its 12 + 0 filing are the same except for a small difference between myself and RECO in the amount of short-term debt included in capital structure.

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 December 2009, obtaining a range of 9.6 to 10.6 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. 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 the DCF studies in establishing the Company's authorized ROE.

Dr. Morin employs several variants of both the DCF and CAPM, along with a historical risk premium analysis. In my opinion, his studies significantly overstate the cost of equity for RECO.

Q. DO YOU INCLUDE AN ADJUSTMENT FOR FLOTATION EXPENSE?

A. Yes, my analysis incorporates a small adjustment for possible flotation expense of 0.1 percent. This is based on the actual costs incurred in recent years for stock issuances by the ultimate parent, Consolidated Edison.

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

A. Yes, very much so, and this is also the clear consensus of credit rating agencies. RECO provides monopoly electric distribution utility service in its New Jersey service territory, subject to the regulatory oversight of the Board. There is no indication of any material increase in the Company's business or financial risk in recent years that would warrant the large increase in the authorized rate of return on equity requested in this case. In Section III of my testimony, I discuss the risk attributes for the Company cited in recent credit rating reports.

Q. HOW DOES YOUR RETURN RECOMMENDATION AT THIS TIME COMPARE WITH RETURNS GRANTED TO THE COMPANY IN ITS LAST ELECTRIC CASE?

A. My recommendation for the equity return and equity ratio is an increase over the Company's currently-authorized distribution return. I believe that my approach of recommending a moderate increase at this time is fair to both customers and the Company, consistent with market evidence and investor requirements and properly emphasizes the need at this time for ratemaking stability and continuity during a period of economic distress for New Jersey. By contrast, the Company's request for a very large increase is both abrupt and unsupportable.

Q. HOW DOES DR. MORIN OBTAIN HIS COST OF EQUITY ESTIMATE OF 11.0 PERCENT?

A. Dr. Morin uses three cost of equity methods -- the DCF, CAPM and Risk Premium. These methods are applied to two proxy groups of electric utilities. The average of his studies, inclusive of his various adjustments, is about 11.0 percent (or higher). One of my principal concerns is his proxy group selection. His proxy electric utilities are primarily vertically-integrated companies, some with significant unregulated merchant generation operations. This is a poor fit with RECO which is purely an electric delivery service utility. Delivery service customers should *not* be charged for the risks of generation supply in their distribution rates. After all, they already pay for generation supply risks in their electric Basic Generation Service (BGS) charges or competitive supply contracts. My testimony discusses in some detail certain disagreements that I have with Dr. Morin's applications of these methods.

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 – December 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 short-term 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]

[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.

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 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 second half of 2009, single-A utility bond yields declined, returning to the roughly 5.5 to 6.0 percent range and have been relatively stable in recent months. This is roughly consistent with (or even lower than) 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. Since then, long-term Treasury yields have moved up somewhat from these extreme historic low levels, as the corporate debt and equity markets have improved. This reflects some sign of a nascent economic recovery (or at least economic stabilization) and an easing of credit spreads, at least for credit-worthy corporations such as RECO and its corporate affiliates.

Q. ACCORDING TO SCHEDULE MIK-2, THERE WAS 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, later in 2008, this trend reversed with commodity prices collapsing and overall inflation essentially disappearing. The CPI in 2009 exhibited essentially zero inflation or even negative inflation compared to 2008. Long-term forecasts for inflation are also modest, i.e., the "consensus" forecast for the GDP deflator is 1.9 to 2.1 percent per year for the next ten years (*Blue Chip Economic Indicators*, October 2009), and consensus inflation forecasts for the next year or two indicate inflation as moderate 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, principally a weak economy. 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 RECO's equity cost rate associated with providing electric distribution utility service. At the present time, however, the market trends since mid or early 2009 are generally favorable with trends of improving stock market, declining corporate bond yields and narrowing credit spreads.

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 in early 2008 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, cost of capital estimation must be approached with caution, a point Dr. Morin properly emphasizes. Certain assumptions embedded in financial markets may not apply as well as they would under more 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 within the past year. Over the course 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 RECO). The stock market to some significant degree has recovered from its March 2009 low levels, and corporate debt cost rates generally show a downward trend. The Fed has committed itself to maintaining near zero levels of short-term interest rates and an aggressive credit easing policy 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 RECO -- operate in a low inflation and capital cost environment, and this environment is expected to continue for the foreseeable future. Although significant equity risks remain, at the present time it appears we are in a low capital cost environment, particularly for "safe haven" utilities. In this environment, I believe continuity in regulatory policy -- including rate of return awards -- is warranted.

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 the proposed 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 Dr. Morin on behalf of the Company and his 11.0 percent cost of equity recommendation.

III. CAPITAL STRUCTURE AND BUSINESS RISK

A. Capital Structure Modifications

Q. HOW HAS THE COMPANY APPROACHED ITS RATEMAKING CAPITAL STRUCTURE?

A. The Company's basic approach is to use the actual consolidated O&R capitalization at December 31, 2010, with certain modifications. This is consistent with what has been used in past RECO rate cases, and I agree that this is a reasonable approach.

Q. WHY DOES THE COMPANY USE THE O&R CAPITAL STRUCTURE INSTEAD OF DIRECTLY USING RECO'S ACTUAL CAPITAL STRUCTURE?

A. It is not feasible to use RECO's own capital structure since RECO does not issue its own debt. Rather, O&R parent is the source of long-term borrowed funds for RECO, necessitating the use of O&R capitalization to establish a reasonable capital structure in this case.

Q. HOW DOES THE O&R CAPITAL STRUCTURE COMPARE WITH THAT OF CONSOLIDATED EDISON?

A. They appear to be reasonably similar, with both having common equity ratios approximating 50 percent or slightly less.

Q. YOU STATE THAT THE COMPANY HAS PROPOSED CERTAIN MODIFICATIONS TO ITS DECEMBER 31, 2009 ACTUAL CAPITAL STRUCTURE. WHAT ARE THOSE MODIFICATIONS?

A. The Company proposes at this time to include short-term debt (as occurred in the last case) in capital structure. For purposes of reflecting a representative level, the Company uses a 2009 12-month average and subtracts out the 12-month averages of interest-bearing Construction Work in Progress (CWIP) and temporary cash investments. As a result of these deductions, only a small amount of “net” short-term debt remains, about $1.8 million. Please note that the Company did not reflect short-term debt in its original filing but has agreed to do so in it is 12 + 0 update.

With respect to long-term debt, the Company originally removed debt from year-end capital structure that was due to mature in 2010. The 12 + 0 update reverses that adjustment and retains the maturing debt. However, the proposed 12 + 0 update does remove from capital structure O&R’s debt that was redeemed for economic reasons in January 2010 ($45 million).

Q. WHAT IS THE RESULTING CAPITAL STRUCTURE?

A. The 12+0 proposed capital structure is approximately 50 percent equity and 50 percent debt, inclusive of a very small amount of short-term debt.

Q. DO YOU AGREE WITH THIS RATEMAKING CAPITAL STRUCTURE?

A. In general, I concur with the Company’s approach. I agree with RECO’s decision to retain in capital structure debt that will be maturing in 2010. Although this is a post-test year known change, it would be inconsistent to remove this debt from capital structure and not recognize new debt issues expected to occur in 2010, including those that would finance the maturing debt. In that regard, the Company states that O&R expects to issue $115 million in new long-term debt in 2010. (Response to RCR-ROR-16)

Q. DO YOU AGREE WITH THE COMPANY’S SHORT-TERM DEBT PROPOSAL?

A. I have some minor differences. Like the Company, I support using a 12-month average, and I do not object to subtracting out CWIP as the Company has done. Since short-term debt is used to support CWIP, and allocated to CWIP for AFUDC accrued purposes, it is reasonable only to reflect the “excess” in capital structure.

However, I do not agree that the Company's short-term cash investments should be subtracted from capital structure, and I have eliminated that reduction. The end result of that correction is that the 2009 "net" balance of short-term debt increases from $1.8 million to $4.0 million, or 0.39 percent of total capital. (Please see Schedule MIK-1, page 2 of 2)

I note that the Company has utilized a 2.5 percent short-term interest rate. In my opinion, this figure is too high. Instead, I am using a more realistic 1.5 percent, reflecting the very low-cost environment for short-term debt. Please note that the February 10, 2010 *Blue Chip Economic Indicators* consensus forecast reports estimates of 0.4 percent in 2010 and 1.8 percent in 2011 for yields on U.S. Treasury bills. Page 2 of Schedule MIK-1 presents the short-term debt cost rates experienced by O&R in 2009.

Q. BASED ON YOUR MODIFICATIONS, WHAT IS YOUR PROPOSED CAPITAL STRUCTURE?

A. With my modifications to the Company's 12+0 proposal, the ratemaking capital structure is 49.85 percent common equity, 49.76 percent long-term debt and 0.39 percent short-term debt. This is significantly stronger (and more expensive) than the capital structure approved by the Board in the Company's last rate case, and well above average for the electric utility industry.

As additional information becomes available, it may be appropriate to modify my recommendation accordingly.

B. <u>Discussion of RECO's Business Risk</u>

Q. DR. MORIN DISCUSSES THE TURMOIL IN FINANCIAL MARKETS AND THE IMPLICATIONS FOR COST OF CAPITAL. DO YOU AGREE WITH HIS DISCUSSION?

A. Dr. Morin briefly discusses in his testimony the turmoil and volatility in capital markets in 2008 and early 2009. My testimony already mentions the improvement in financial markets and stabilization that has occurred since the time frame in mid-2009 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 during the past year, even though the U.S. economy remains quite weak. Moreover, this economic weakness is a key factor helping 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 relative "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 natural gas utility group, Value Line notes that gas 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 finds that these companies have "provided fairly safe haven amid the recessionary environment" and it notes the 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 late 2008 and early 2009, there was pronounced stock market volatility and plunging prices. 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 3 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 December 2009. This table demonstrates that in June 2008 the betas for the proxy utilities averaged 0.87, whereas by December 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 as compared to common stocks generally.

Table 3

Utility Betas Comparison
(June 2008 vs. June 2009)

Gas Utilities	2008	2009
AGL Resources	0.85	0.75
Atmos	0.85	0.65
LaClede	0.90	0.60
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	0.75
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 11, 2008, December 11, 2009)

Q. DOES RECO SHARE IN THIS RISK REDUCTION?

A. Yes, very much so. RECO, 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 RCR-ROR-2 for itself and its corporate parents, i.e., O&R and Consolidated Edison. As a general matter, these credit rating reports indicate that RECO (or more generally, O&R), as a regulated delivery service utility, has very low business risk.

S&P does not separately evaluate RECO, but considers its credit quality in the overall context of Consolidated Edison, the ultimate parent. In that regard, S&P notes the “excellent business profile” with “low-risk electricity and natural gas operations.” However, S&P is concerned with Consolidated Edison’s large capital spending program, its need for external capital and the pressure that large capital expansion that can place on credit metrics. (Report of September 28, 2009)

Fitchratings has a similar assessment although it does make distinctions between O&R/Rockland and Consolidated Edison. Interestingly, Fitchrating assigns a slightly higher issuer default rating to O&R/Rockland than Consolidated Edison (i.e., A- versus BBB+ for issuer default rating). The agency notes O&R/Rockland as having low business risk, stable cash flows and insulation from commodity risk due to prompt and full recovery of power supply costs incurred for default service. (Report of October 20, 2009)

Finally, Moody’s also see O&R/Rockland as having low business risk although it has recently downgraded the Company to Baa(1) (“stable”) due to weakening financials. Moody’s reports a “low business risk profile but challenging regulatory and economic environments.” The report further states that “Moody’s views O&R’s regulated T&D operations as having a low business risk profile.” An important reason for this low business risk is that regulation insulates O&R/Rockland from commodity risk. (Report of June 2009)

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 RECO. I believe that these utility companies, on average, are similar to or in some cases even slightly riskier than RECO, particularly some of the electric distribution utilities.

Q. HAS DR. MORIN FOLLOWED THE SAME APPROACH OF UTILIZING COMPANIES SIMILAR IN BUSINESS RISK TO RECO?

A. I do not believe he has successfully done so. He instead has selected groups of electric and combination electric/gas companies that generally are not risk comparable to RECO. Most of the electrics he selected are vertically-integrated, in some cases with substantial unregulated merchant power operations. Generation, and particularly merchant generation, typically is perceived as riskier than monopoly utility delivery service by credit rating agencies and investors generally. My reading of his testimony is that he makes no comparisons of the business risks of his proxy companies with RECO.

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, the Board 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. RECO'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. 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 Dr. Morin), I also perform a CAPM study which 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 the New Jersey BPU 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 RECO, which is a wholly-owned subsidiary of O&R, and therefore a market proxy is needed. O&R, in turn, is owned by Consolidated Edison, which is a publically-traded Company. I have included Consolidated Edison as one of my proxy companies, and I note that Dr. Morin does so as well.

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.

In that regard, Dr. Morin uses stock prices averaged over a much shorter time period, Value Line prices as of June 2009. In my opinion the six-month average is a preferable approach.

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 RECO, which in this case is pure electric delivery service. 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 RECO) operate in Mid-Atlantic or 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 significant gas operations. With these three eliminations, I have a proxy group of nine companies that operate predominantly as monopoly utilities.

B. DCF Study Using the Proxy Group of Gas Distribution Utility Companies

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 RECO.

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 DR. MORIN PROPOSED A SPECIFIC RISK ADJUSTMENT TO THE COST OF EQUITY BETWEEN THE PROXY COMPANIES AND RECO?

A. No, not specifically for differences in business risk. However, Dr. Morin does suggest a very small adjustment that pertains to capital structure. Specifically, he develops a range of 11.0 to 11.5 percent and recommends the lower end of his range based on RECO's proposed capital structure.

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 December, 2009, the most recent data available to me as of this writing. This covers the last half of 2009, a period of some financial distress but also some gradual improvement in markets, as noted by the Fed Chairman Bernanke in recent statements.

I show these dividend yield data on page 2 of Schedule MIK-4 for each month and each proxy company, July through December 2009. Over this six-month period the group average dividend yields were relatively stable, but gradually diminishing, ranging from a low of 4.14 percent in December to a high of 4.46 percent in November 2009, averaging 4.35 percent for the full six months.

For DCF purposes and at this time, I am using a proxy group dividend yield of 4.35 percent.

Q. IS 4.35 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 4.5 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 DR. MORIN 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" 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 due to this adjustment is relatively 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.

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 Dr. Morin relies entirely 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. Even Dr. Morin expresses caution in the application of the DCF model (as well as the CAPM approach) during periods of market turmoil.

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

Conditions are presently very unusual in that 2008 to 2009 has been 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 as part of my DCF analysis.

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 5.33 percent for CNNfn, 5.59 percent for First Call, 5.84 percent for Zacks and 4.56 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 5.33 percent. To recognize uncertainty, I have identified a reasonable range of 5.0 to 5.5 percent which is approximately consistent with the earnings growth rates, along with other information that I have compiled.

Q. HAVE YOU SEEN OTHER EVIDENCE THAT SUGGESTS THE FIVE-YEAR EARNINGS GROWTH RATES COULD OVER-STATE THE LONG-TERM GROWTH RATE?

A. Yes. I consulted the October 2009 edition of *Blue Chip Economic Indicators*, a very well-known financial/economic publication that compiles short and long-term forecasts from major forecasting organizations. It publishes the forecast averages from nearly 40 such organizations which are referred to as the Blue Chip "consensus" results. The October 2009 edition includes a ten-year forecast of U.S. pre-tax profit growth. The growth rate consensus is as follows:

2010	-- 10.6%
2011	-- 9.1%
2012	-- 7.0%
2013	-- 5.9%
2014	-- 5.2%
2015	-- 4.7%
2011 – 2015	-- 6.4%
2016 – 2020	-- 5.0%

This shows rapid growth in U.S. profits initially as an economic recovery takes hold, but then profit growth tails off and stabilizes at a lower level of growth. The average growth rate for the next five years is 6.4 percent per year, but after that it slows to 5.0 percent per year. This is a 1.4 percentage point drop off after the first five years. I have little doubt that this slow down pattern to some degree is also true for the proxy companies that both Dr. Morin and I have used. This very strongly suggests that the five-year earnings growth rates that both he and I use are overstated as representing long-run growth expectations that the DCF model requires.

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 significant weight, these growth rates also must 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 3.61 percent, book value growth averages 4.33 percent, and earnings retention growth averages 5.06 percent. Earnings retention is an important growth measure, and helps to form the basis of using a 5.0 percent lower bound.

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 December 2009 is 4.5 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 9.6 percent to 10.1 percent. As explained below, I include 0.1 percent for flotation expense to obtain a final cost of equity of 9.6 to 10.1 percent, with a midpoint of 9.85 percent.

Q. WHY 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.

As a wholly-owned subsidiary, RECO does not issue common stock to the public and therefore does not directly incur flotation costs. However, its parent (or ultimate parent) may incur such costs on RECO's behalf. I therefore have reviewed Consolidated Edison's experience with such costs in recent years to determine whether a flotation adjustment is warranted.

Q. HOW DID YOU APPROACH THIS ISSUE?

A. I requested Consolidated Edison's experience during the past five years with public issuances of common stock. In response to RCR-ROR-17, the Company provided the following data on public stock issuances (millions $).

Year	Net Proceeds	Expenses
2007	$ 558	$2.2
2006	447	3.8
2004	513	15.9
Total	$ 1,518	$21.9

Since 2004, Consolidated Edison has issued $1.5 billion of equity through public issuances at a cost of $22 million. Notably, the $22 million is 1.4 percent of net proceeds – far less than the 5 percent cost figure used by Dr. Morin in developing his flotation adjustment. The total of $22 million is approximately $4.5 million per year. Since the Consolidated Edison common equity balance is about $10 billion, the annualized cost of $4.5 million translates into 0.05 percent on equity ($4.5 / $10,000 = 0.05 percent). I have rounded this up to 0.1 percent, and I include this as a flotation adder on page 1 of Schedule MIK-4.

Q. THIS CASE IS INTENDED TO SET RATES FOR RECO'S ELECTRIC OPERATIONS. IS A GAS PROXY GROUP RELEVANT TO THE ELECTRIC OPERATIONS?

A. Yes, very much so. A local gas distribution company provides 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 as a proxy for RECO's electric ROE determination. Unfortunately, that is not the case today. I was hard pressed to assemble a group of seven such distribution electrics, and Dr. Morin apparently chose to settle for a group that is mostly vertically-integrated and/or merchant generation companies.

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

A. Yes. In 2004, S&P developed and implemented a new system for ranking the business risks of utility and power companies.[2] Companies were placed for business risk comparative purposes into five categories:

1. Transmission and distribution – water, gas and electric

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

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

RECO was included by S&P in Category (1), i.e., with the gas distribution companies for business risk purposes. S&P has recently moved to a more streamlined system for ranking utility business risks, but that does not change the fact that the business risks of electric and gas utility distribution are viewed as being similar.

It is important to note that vertically-integrated electrics (the business type that dominates Dr. Morin's two proxy groups) are in a totally separate risk group that excludes RECO. This is an indication that as a general matter, S&P views vertically-integrated operations as somewhat riskier than utility delivery service. The riskiest category of all is unregulated merchant generation and marketing, and some of Dr. Morin's proxy 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 RECO's electric operations. The absolute worst risk proxy for RECO would be a company with substantial merchant generation (or other unregulated operations).

C. <u>Electric Company DCF Study</u>

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 RECO, 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 and operate under a traditional regulation paradigm. 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. Companies that I intentionally excluded are 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 RECO's monopoly delivery service.

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 and not as strong as Consolidated Edison, RECO's parent.

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 Mid-Atlantic or Northeast Regional Transmission Organizations ("RTOs"), i.e., PJM, New York ISO or New England. All are engaged primarily in electric delivery service (with some gas utility operations as well). 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 appears minor and does not warrant excluding this company.

Another company, Pepco, is also primarily a delivery service utility, but it also has substantial non-regulated operations, including both energy marketing and merchant generation. These non-regulated activities are quite meaningful and considered risky, but they are 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 Dr. Morin has selected Pepco for his own proxy groups, 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 December 2009 is 5.39 percent. Using the standard “0.5g” forward adjustment, the going forward yield becomes 5.5 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 4.0 to 5.0 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 5.07 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 5.0 percent upper end of my 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 2.1 percent and tells us little about long-term growth expectations. Book value and earnings retention growth for this group average 3.6 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., 4.0 percent. Averaging the three measures together would produce a growth rate of about 3.0 percent, but I disregard the projected dividend growth rate figure as being an unrealistically low estimate of long-term growth.

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 (5.5 percent) plus growth average (4.0 to 5.0 percent), or 9.5 to 10.5 percent. With a flotation cost adjustment, the cost of equity is 9.6 to 10.6 percent, with the midpoint of this range 10.1 percent, which is slightly higher though similar to my gas utility proxy group DCF study result. The electric and gas proxy results are similar, with the gas somewhat lower. As discussed in the next section, the CAPM studies support a somewhat lower return estimate.

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 Dr. Morin's three cost of equity methods. (He employs two versions of the CAPM, i.e., the "standard" CAPM, and the so-called "empirical" CAPM, or "ECAPM".)

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 Dr. Morin 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 Dr. Morin and I use Value Line published betas, but for comparative purposes I note that other sources have somewhat different (and lower) utility betas, that would yield lower results. For that reason, I have reviewed other published sources, along with Value Line, to obtain a range of betas for comparative purposes. This is analogous to the procedure followed by Dr. Morin and me in using multiple published sources for DCF earnings growth rates rather than relying on just one published 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 4.50 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 0.4 to 0.5. 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. I note that Dr. Morin also has elected to use a beta of 0.74 for his proxy companies (obtained from Value Line). 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 4.5 percent, a proxy group beta of 0.70 and an equity risk premium of 5 percent.

$$K_e = 4.5\ \% + 0.7\ (5.0) = 8.0\%$$

The upper end estimate also uses a risk-free rate of 4.5 percent, a proxy group beta of 0.70 and an equity risk premium of 8.0 percent.`

$$K_e = 4.5\% + 0.7\ (8.0) = 10.1\%$$

Thus, with these inputs the CAPM provides a cost of equity range of 8.00 to 10.1 percent, with a midpoint of 9.1 percent. The 9.1 percent midpoint should be increased by 0.1 percent to 9.2 percent to account for flotation expense as discussed earlier. 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 in the past due (in part) to the “flight to quality” problem that I discussed earlier. At the present time, it is possible that 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 DR. MORIN’S MARKET RISK PREMIUM?

A. For his CAPM studies, Dr. Morin has selected a market risk premium of 6.5 percent, which happens to be the midpoint of my range. Dr. Morin uses a somewhat higher beta (0.74) and includes 0.3 percent for flotation expense. With these inputs, he obtains 9.6 percent compared to my 9.2 percent midpoint.

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 10.5 percent (i.e., 6.0 + 4.5 = 10.5 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 stock market equity return of about 9.5 to 12.5 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 note that Dr. Morin's risk premium selection is consistent with the midpoint of that range.

There is one important caveat to consider regarding the 5 to 8 percent risk premium range that Brealy, *et al.* believe is supported by the professional literature (or their interpretation of that literature). It appears that the 5 to 8 percent risk premium range is relative to short-term Treasury 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 in the CAPM as both Dr. Morin and I have done.

V. REVIEW OF DR. MORIN'S RECOMMENDATION

A. Recommendation Overview

Q. HOW DID DR. MORIN DEVELOP HIS 11.0 PERCENT RECOMMENDATION?

A. Dr. Morin employs three cost of equity approaches, using a range of proxy companies and data inputs. These studies produce a fairly wide range of results, from approximately 9.6 to 12.5 percent. He develops his 11.0 percent recommendation by averaging the results of these various studies. It should be noted that his study results are inclusive of a flotation cost recovery factor of 0.3 percent, and therefore his studies and presumably his recommendation would average to about 10.7 percent absent the inclusion of this factor.

It should be noted that Dr. Morin's studies appear to be based mostly on market data from June 2009, and he did not submit an update in conjunction with the Company's 12+0 filing in January 2010. His testimony states that he may submit an update later in this case, if conditions warrant.

For convenience, I reproduce below Dr. Morin's summarization of his cost of equity study results taken directly from page 46 of his testimony (inclusive of his flotation adjustments):

1.	CAPM	9.6%
2.	Empirical CAPM	10.0
3.	Risk Premium	11.3
4.	S&P Electrics DCF (Value Line)	12.1
5.	S&P Electrics DCF (Zacks)	12.5
6.	Gas/Electric DCF (Value Line)	12.4
7.	Gas/Electric DCF (Zacks)	12.3
	Average	**11.46%**

The mean of these seven studies is 11.46 percent and the median is 12.1 percent.

Based on these results, Dr. Morin states that the mean of his three principal methods (i.e., CAPM, Risk Premium and DCF) is 11.1 percent and he identifies a recommended cost of equity range of 11.0 to 11.5 percent. However, he recommends the lower end of his range, 11.0 percent, for RECO due to its proposed capital structure in this case (i.e., 54 percent equity ratio), which is stronger than the capital structures of his proxy companies.

Q. THE COMPANY HAS MODIFIED ITS CAPITAL STRUCTURE IN ITS 12+0 FILING, REDUCING ITS EQUITY RATIO FROM 54 TO 50 PERCENT. DID THE COMPANY INCREASE ITS REQUESTED ROE AS SUGGESTED BY DR. MORIN?

A. No. The Company has retained its original 11.0 ROE request, and chose not increase the proposed ROE as Dr. Morin recommended.

Q. ARE ALL SEVEN STUDIES LISTED ABOVE BASED ON PROXY GROUPS?

A. Yes. Dr. Morin relies primarily on two proxy groups: (1) the 27 companies comprising the S&P electric utility index; and (2) a group of 22 companies that he refers to as "combination gas and electric utilities". These two groups are used with both his CAPM and DCF studies. In addition, he uses the S&P electric utility group for conducting his historical Risk Premium study. The study results cited above are those obtained for these proxy groups.

Q. DOES DR. MORIN PROPOSE ANY ADJUSTMENTS TO COMPENSATE FOR COST OF CAPITAL BUSINESS RISK DIFFERENCES BETWEEN RECO AND THE TWO PROXY GROUPS?

A. No, not in formulating his 11.0 percent return on equity recommendation. I do not read his testimony as suggesting in any way that RECO is viewed by investors as either riskier or less risky than the proxy group averages. However, he would increase his ROE recommendation by about 10 basis points for each one percentage point reduction in the 54 percent equity ratio proposed by RECO in this case. This proposed adjustment was not adopted by RECO in its 12 + 0 update recently filed.

Q. DR. MORIN DISCUSSES THE TURMOIL IN FINANCIAL MARKETS WHICH BECAME EVIDENT IN 2008 AND TO SOME DEGREE WAS STILL PRESENT IN JUNE 2009 WHEN HE PREPARED HIS TESTIMONY. HAS THIS AFFECTED HIS COST OF CAPITAL RECOMMENDATION?

A. I see no evidence that this "turmoil" has resulted in a higher cost of capital recommendation from Dr. Morin for RECO. In recent years prior to 2008, my understanding is that Dr. Morin has been recommending utility ROEs in the 11.0 to 12.0 percent range. His current recommendation of 11.0 percent is similar to and if anything may be slightly lower than in past cases.

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

Q. HOW DID DR. MORIN APPLY THE DCF MODEL?

A. He applies the standard "yield plus growth" DCF formula to two groups of electric companies. The first is a group of 22 combination electric/gas companies, and the second is a group that consists of 27 companies in the S&P electric utility index. Dr. Morin states that companies included in these two groups must (a) have investment grade credit ratings (i.e., no lower than BBB-); (b) be included in the Value Line data base; (c) have utility revenues at least 50 percent of total revenues; and (d) market capitalization exceeding $500 million.

For DCF calculation purposes, he uses dividend yields as of June 2009 and five-year earnings growth rates published by Value Line and Zacks as a proxy for long-run dividend growth. Using these companies and data inputs he calculates group average cost of equity results of about 12 to 13 percent – well above his 11.0 percent recommendation.

It should be noted that Dr. Morin includes in his stated cost of equity results two adjustments. The first is the forward adjustment to the dividend yield of 0.3 to 0.4 percent that I discussed earlier in connection with my study. The second is the 0.3 percentage point adder for flotation expense – a total of 0.6 to 0.7 percent. While I support in this case both a dividend yield adjustment and an issuance cost adder, the 0.6 to 0.7 percentage point adders are excessive.

Q. OTHER THAN THESE ADDERS, WHAT ARE YOUR CONCERNS WITH HIS DCF STUDIES?

A. The 12.0 to 13.0 percent DCF results clearly are outlandishly high and unrealistic. For example, Mr. Morin estimates a risk premium for the overall U. S. stock market of 6.5 percent, which with his long-term Treasury rate of 4.5 percent translates into a cost of equity *for the overall stock market* of 11.0 percent. Dr. Morin's DCF results imply that the cost of equity for his proxy utility companies exceeds significantly his estimate for overall the U. S. stock market (i.e., the S&P 500).

There are two rather serious problems with his DCF studies. The first is that his two selected proxy groups are not very closely related in business risk to RECO's electric distribution operations. With only a few exceptions, the companies are either vertically-integrated electrics, major players in the unregulated merchant power business or both. Prominent merchant power companies in his proxy groups include Duke Energy, Entergy Corporation, Exelon Corporation, FirstEnergy, Allegheny Energy, PPL Corp., Dominion Resources and Public Service Enterprises Group.

The DCF study results therefore reflect these risks. Unlike RECO, these companies are exposed to substantial commodity risks.

The risk profile of these groups, and particularly the large merchant generation companies, has little in common with the monopoly regulated electric distribution operations of RECO. Vertically-integrated electrics and merchant power should not be used as a risk proxy for RECO to set the fair return in this case.

Q. WHAT IS THE SECOND PROBLEM?

A. As discussed in Section IV of my testimony, the published five-year earnings growth rates may tend to overstate the long-term sustainable growth rate in dividends that the standard DCF model requires. As a general matter, analysts expect very rapid near-term growth in earnings as the U. S. economy recovers, but it then slows down after a few years to a more sustainable pace. Dr. Morin records five-year growth for his proxy groups of about 6 percent per year. Such growth may be reasonable for a short period of time, but it overstates the long–term sustained growth rate that investors reasonably would expect.

C. <u>CAPM Analysis</u>

Q. ONE OF DR. MORIN'S PRINCIPAL METHODS IS CAPM. DO HIS CAPM STUDIES CONFLICT WITH YOUR RETURN ON EQUITY RECOMMENDATION IN THIS CASE?

A. Both Dr. Morin and I obtain CAPM cost of equity results near or below 10 percent which supports the reasonableness of my 10.1 percent recommendation. For that reason, I discuss his CAPM analyses only briefly.

Q. DR. MORIN PREPARED HIS CAPM ANALYSES IN JUNE 2009. WHAT RESULTS DOES HE OBTAIN?

A. Dr. Morin uses CAPM inputs very similar to what I have used: a risk-free rate (i.e., yield on long-term Treasury bonds) of 4.5 percent, beta of 0.74 and an equity risk premium of 6.5 percent:

$$\mathbf{K_e = 4.5\% + 0.74\ (6.5) = 9.3\%}$$

He adds 0.3 percent for flotation expense obtaining a final CAPM cost of equity of 9.6 percent.

In addition to my difference with Dr. Morin on flotation expense, my only other disagreement is his use of a 0.74 beta obtained from his two proxy groups, as discussed earlier.

Q. DO YOU HAVE ANY METHODOLOGICAL DISAGREEMENT WITH DR. MORIN'S CAPM?

A. In addition to using the standard or conventional CAPM, Dr. Morin also employs the Empirical CAPM (ECAPM). This calculation is a weighted average of the standard CAPM (given a 75 percent weight) and an alternative CAPM which assumes a beta equal to 1.0 (given a 25 percent weight). Using his testimony parameters, the ECAPM produces a return of 9.7 percent (10.0 percent with flotation adder). Again, this is below my recommendation in this case. It is notable that the ECAPM will almost always produce a cost of equity result for utilities higher than the conventional CAPM. This is because utilities are low in risk compared to the overall stock market and therefore have betas below 1.0.

Q. HAS THE ECAPM RECEIVED REGULATORY SUPPORT?

A. Not to my knowledge. While Dr. Morin has been using this model for many years in utility rate cases, it has not received significant regulatory acceptance.

Q. IS THERE EVIDENCE SUPPORTING THE NEED FOR THE ECAPM CORRECTION?

A. I do not believe there is for utilities. In response to RCR-ROR-22, Dr. Morin cites research literature that he believes supports the use of the ECAPM, but that research is not specifically focused on utilities. This is important because utilities have risk attributes that make them qualitatively different from unregulated firms, and this is well understood by investors. Hence studies based on data mostly from unregulated companies would not necessarily be applicable to utilities.

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

Q. HOW DID MR. MORIN CONDUCT HIS RISK PREMIUM STUDY?

A. As explained in his testimony, he calculated the long-term average annual market return on the S&P Utility Index minus the long-term average annual return on utility bonds for the same time period. Using this approach, he calculates a utility equity risk premium of 5.0 percent. He adds this premium to the then current long-term utility yield of 6.0 percent, obtaining 11.0 percent to which he adds 0.3 percent for flotation expense, obtaining a final Risk Premium cost of equity estimate of 11.3 percent.

Q. IS THIS STUDY A RELIABLE ESTIMATES OF RECO'S COST OF EQUITY?

A. No, there are several weaknesses. First, the specific results he obtains tend to be sensitive to the time period selected. Dr. Morin claims that the average annual risk premium for 1932 to 2007 (about 75 years) for the S&P Utility Index relative to bond returns is 5.0 percentage points. However, using the data from the most recent quarter century (i.e., 1983 to 2007), the equity risk premium is cut in half to a mere 2.7 percent, on average. Using this methodology, this would strongly suggest that in recent decades the equity risk premium for utility stocks has declined significantly as compared to the much earlier 1932-1982 time period. Risk premia calculations from the past 25 years simply cannot support a 2009 cost of equity calculation anywhere close to his 11.0 percent result, i.e., closer to about 9 percent.

A second and perhaps more serious problem is that this risk premium study has little to do with RECO. The stock index that Dr. Morin uses consists almost entirely of integrated and/or merchant electric companies, with almost no companies that are primarily distribution utilities. In addition, the S&P utility index that he used includes some of the largest names in unregulated merchant generation: AES Corp., Allegheny Energy, Constellation, Entergy Corp., Exelon, FirstEnergy, Public Service Enterprise Group, PPL Corp. and others. The business operations and risk profiles of such companies are vastly different from stable, low-risk distribution utility like RECO. Hence, the 11.0 percent cost of equity estimate for this group – even if deemed reliable – is not applicable in this case to RECO.

A third problem is that Dr. Morin intentionally truncates his historical risk premium series in 2007, ignoring the large negative equity premium in 2008. Dr. Morin was asked to update his analysis to include 2008 data (RCR-ROR-21). The update should significantly *reduce* his Risk Premium cost of equity. In response to this request, Dr. Morin provided an update that appears to be based on Treasury bonds rather than utility bonds, indicating a risk premium of 5.6 percent. When added to his Treasury bond yield of 4.5 percent, this implies a 10.1 percent cost of equity (5.6% + 4.5% = 10.1%) before consideration of RECO's lower business risk as compared to the S&P utility index.

Q. WHAT DO YOU CONCLUDE CONCERNING THE UTILITY RISK PREMIUM EVIDENCE?

A. Setting aside the flotation adder, Dr. Morin obtains 11.0 percent. However, he obtains this result only by refusing to update and using data extending back to 1932.

After accounting for updating, RECO's lower risk relative to the S&P utility index, and giving some consideration to shorter time periods (e.g., the past 25 years), the Risk Premium would tend to support a cost of equity for RECO in the 9 to 10 percent range. However, this methodology has shortcomings, and I do not recommend reliance on the historical Risk Premium method for setting RECO's authorized return in this case.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

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STATE OF NEW JERSEY
OFFICE OF ADMINISTRATIVE LAW
BEFORE ADMINISTRATIVE LAW

I/M/O THE VERIFIED PETITION OF	)	
ROCKLAND ELECTRIC COMPANY	)	
FOR APPROVAL OF CHANGES IN	)	**BPU DOCKET No. ER09080668**
ELECTRIC RATES, ITS TARIFF FOR	)	**OAL DOCKET No. PUC-11407-09**
ELECTRIC SERVICE, ITS	)	
DEPRECIATION RATES, AND FOR	)	
OTHER RELIEF	)	

SCHEDULES
ACCOMPANYING THE
TESTIMONY OF MATTHEW I. KAHAL
ON BEHALF OF THE
NEW JERSEY DEPARTMENT OF THE PUBLIC ADVOCATE
DIVISION OF RATE COUNSEL

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FILED: MARCH 5, 2010

ROCKLAND ELECTRIC COMPANY

Overall Rate of Return Summary
(at December 31, 2009)

Capital Type	($000) Balance[1]	% of Total	Cost Rate	Weighted Cost
Long-Term Debt	$ 521,503	49.76%	6.16%	3.07%
Preferred Stock	0	0.00	0.00	0.00
Short-Term Debt	4,044[2]	0.39	1.5	0.01
Common Equity	522,465	49.85	10.10[3]	5.04
Total	**$1,048,012**	**100.00%**	**--**	**8.12%**

[1] Exhibit P-4, Schedule 1, 12 + 0 Update.

[2] See page 2 of this schedule.

[3] See testimony and Schedules MIK-4, 5 and 6.

ROCKLAND ELECTRIC COMPANY

O&R Consolidated Short-Term Debt Balances, Cost Rates and CWIP
(January – December 2009)
(Millions $)

	Balance	Cost Rate	CWIP AFUDC Eligible
January 2009	$ 71.8	0.60%	$ 37.5
February	82.4	0.55	35.7
March	87.8	0.56	33.9
April	44.7	0.35	36.6
May	35.7	0.30	37.0
June	23.2	0.40	37.9
July	14.5	0.40	37.9
August	7.9	--	43.6
September	34.8	0.29	44.5
October	81.3	0.25	51.5
November	62.8	0.28	57.3
December	12.8	--	57.8
Average	**$ 46.7**	**0.40%**	**$ 42.6**

Source: Responses to RCR-ROR-32 and 33.

Note: Rockland Electric 12-month average CWIP is $0.8 million.

ROCKLAND 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
2009	(0.4)	3.2	0.2	6.0

ROCKLAND 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

ROCKLAND 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

ROCKLAND 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	(1.5)	3.6	0.2	5.7
September	(1.3)	3.4	0.1	5.5
October	(0.2)	3.4	0.1	5.6
November	1.8	3.4	0.1	5.7
December	2.5	3.6	0.1	5.7(p)

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

ROCKLAND 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 excludes short-term debt (and current maturities of long-term debt).

Source: *Value Line Investment Survey*, December 11, 2009

ROCKLAND 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*, November 17, 2009

ROCKLAND ELECTRIC COMPANY

DCF Summary for
Gas Distribution Proxy Group

1.	Dividend yield (July – December 2009)	4.35%[(1)]
2.	Adjusted yield ((1) x 1.0275)	4.5%
3.	Long-term Growth Rate	5.0 - 5.5[(2)]
4.	Total Return ((2) + (3))	9.5 - 10.0%
5.	Flotation Adjustment	0.1%
6.	Cost of equity ((4) + (5))	9.6 - 10.1%
7.	Midpoint	9.85%
Recommendation		**10.1%**

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

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

ROCKLAND ELECTRIC COMPANY

Dividend Yields for Gas Distribution Proxy Group
(July – December 2009)

	Company	July	August	September	October	November	December	Average
1.	AGL Resources	5.1%	5.1%	4.9%	4.8%	5.0%	4.7%	4.93%
2.	Atmos	4.9	4.8	4.7	4.6	4.9	4.6	4.75
3.	LaClede	4.6	4.7	4.8	4.9	5.0	4.7	4.78
4.	NICOR	5.1	5.1	5.1	5.0	4.7	4.4	4.90
5.	Northwest Nat.	3.5	3.8	3.8	3.9	3.9	3.7	3.77
6.	Piedmont	4.4	4.5	4.5	4.6	4.6	4.0	4.43
7.	South Jersey	3.2	3.4	3.4	3.4	3.7	3.5	3.43
8.	Southwest Gas	3.9	3.9	3.7	3.8	3.6	3.3	3.70
9.	WGL	4.4	4.5	4.4	4.4	4.7	4.4	4.46
	Average	**4.34%**	**4.42%**	**4.37%**	**4.38%**	**4.46%**	**4.14%**	**4.35%**

Source: S&P *Stock Guide*, August 2009 – January 2010 editions.

ROCKLAND 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%	4.0%	4.5%	7.0%	4.75%
2.	Atmos	4.0	5.0	5.0	5.0	4.75
3.	LaClede	3.5	3.5	3.0	3.0	3.25
4.	NICOR	1.5	4.4	4.2	4.0	3.53
5.	Northwest	5.0	6.0	5.8	5.0	5.45
6.	Piedmont	8.0	6.6	7.0	4.0	6.40
7.	South Jersey	5.5	9.8	11.1	9.0	8.85
8.	Southwest	6.0	6.0	7.0	6.0	6.25
9.	WGL	4.0	5.0	5.0	5.0	4.75
	Average	**4.56%**	**5.59%**	**5.84%**	**5.33%**	**5.33%**

Sources: *Value Line Investment Survey*, December 11, 2009. First Call is from Yahoo Finance website (December 2009) and Zacks is from MSN Money website (December 2009). In addition, the CNN figures are from the CNNfn web site (December 2009).

ROCKLAND 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%	2.5%	5.5%
2.	Atmos	1.5	4.0	4.0
3.	LaClede	2.5	5.5	5.0
4.	NICOR	0.0	4.5	4.5
5.	Northwest	6.5	5.0	4.5
6.	Piedmont	3.5	4.0	6.0
7.	South Jersey	8.0	5.0	7.0
8.	Southwest	5.0	4.0	4.5
9.	WGL	3.0	4.5	4.5
	Average	**3.61%**	**4.33%**	**5.06%**

Source: *Value Line Investment Survey*, December 11, 2009. The earnings retention figures are projections for 2012-2014.

ROCKLAND ELECTRIC COMPANY

DCF Summary for
Electric Distribution Utility Proxy Group

1. Dividend Yield (July – December 2009)	5.39%[1]
2. Adjusted Yield ((1) x 1.022)	5.5%
3. Long-Term Growth Rate	4.0 – 5.0[2]
4. Total Return ((2) + (3))	9.5 - 10.5%
5. Flotation Adjustment	0.1%
6. Cost of Equity ((4) + (5))	9.6 - 10.6%
7. Midpoint	10.1%
Recommendation	**10.1%**

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

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

ROCKLAND ELECTRIC COMPANY

Dividend Yields for Electric Distribution Utility Proxy Group
(July –December 2009)

	Company	July	August	September	October	November	December	Average
1.	CH Energy	4.4%	4.7%	4.9%	5.2%	5.3%	5.1%	4.93%
2.	Central Vt.	5.0	5.0	4.8	4.7	4.8	4.4	4.78
3.	Consolidated Ed.	6.0	5.9	5.8	5.8	5.5	5.2	5.70
4.	Northeast Utilities	4.1	4.0	4.0	4.1	3.9	3.7	3.97
5.	NSTAR	4.7	4.7	4.7	4.8	4.8	4.3	4.67
6.	Pepco Holdings, Inc.	7.5	7.5	7.3	7.2	6.7	6.4	7.10
7.	UIL Holdings	7.1	6.7	6.5	6.7	6.4	6.2	6.60
	Average	**5.54%**	**5.50%**	**5.43%**	**5.50%**	**5.34%**	**5.04%**	**5.39%**

Source: Standard & Poors, Stock Guide, August 2009-January 2010 editions.

ROCKLAND 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	3.5%	NA	NA	NA	3.50%
2.	Central Vt.	3.0	8.9%	NA	NA	5.95
3.	Consolidated Ed.	3.0	3.4	3.6%	4.0%	3.50
4.	Northeast Utilities	8.0	8.6	8.9	7.0	8.13
5.	NSTAR	8.0	5.7	6.0	6.0	6.43
6.	Pepco Holdings, Inc.	0.0	5.5	5.5	5.0	4.00
7.	UIL Holdings	3.5	4.5	4.0	4.0	4.00
	Average	**4.14%**	**6.10%**	**5.60%**	**5.20%**	**5.07%**

Sources: *Value Line Investment Survey*, November 27, 2009. First Call is from Yahoo Finance website (January 2010) and Zacks is from MSN Money website (January 2010). In addition, the CNN figures are from the CNNfn web site (January 2010).

ROCKLAND 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%	2.0%	2.5%
2.	Central Vt.	1.0	6.5	3.5
3.	Consolidated Ed.	1.0	3.5	3.5
4.	Northeast Utilities	7.0	4.5	4.0
5.	NSTAR	5.5	5.5	6.0
6.	Pepco Holdings, Inc.	0.0	1.0	2.5
7.	UIL Holdings	0.0	2.5	2.5
	Average	**2.07%**	**3.64%**	**3.50%**

Source: *Value Line Investment Survey*, November 27, 2009. The earnings retention figures are projections for 2012-2014.

ROCKLAND 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 = 4.5% (Treasury long-term bond yields for the most recent six months, see page 2 of 3)

Rm = 9.5 – 12.5% (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 = 4.5% + 0.7 (5.0) = 8.00%
Midpoint:	K_e = 4.5% + 0.7 (6.5) = 9.05%
Upper End:	K_e = 4.5% + 0.7 (8.0) = 10.1%

ROCKLAND ELECTRIC COMPANY

Long-Term Treasury Yields
(August 2009 – January 2010)

	10-Year	20-Year	30-Year
August 2009	3.6%	4.3%	4.4%
September	3.4	4.1	4.2
October	3.4	4.2	4.2
November	3.4	4.2	4.3
December	3.6	4.4	4.4
January 2010	3.7	4.5	4.7
Average	**3.5%**	**4.3%**	**4.4%**

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

ROCKLAND 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	0.44	0.54
2. Atmos	0.65	0.50	0.51	0.54
3. LaClede	0.60	0.02	-0.10	0.19
4. NICOR	0.75	0.34	0.34	0.48
5. Northwest Natural	0.60	0.25	0.22	0.36
6. Piedmont	0.65	0.18	0.14	0.32
7. South Jersey	0.65	0.21	0.20	0.36
8. Southwest Gas	0.75	0.70	0.72	0.71
9. WGL	0.65	0.21	0.15	0.34
Average	**0.67**	**0.31**	**0.29**	**0.42**

Electric Distribution Utilities

Company	Value Line	Yahoo Finance	MSN Money	Average
1. CH Energy	0.65	0.37	0.39	0.47
2. Central Vt.	0.80	0.55	0.68	0.68
3. Consolidated Ed.	0.65	0.26	0.27	0.39
4. Northeast Utilities	0.70	0.48	0.49	0.56
5. NSTAR	0.65	0.20	0.25	0.37
6. Pepco Holdings, Inc.	0.80	0.53	0.57	0.63
7. UIL Holdings	0.70	0.73	0.73	0.72
Average	**0.71**	**0.45**	**0.48**	**0.55**

Sources: *Value Line Investment Survey*, December 11, 2009.
MSN Money and Yahoo Finance, September 2009.

APPENDIX A

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.

Publications and Consulting Reports:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Conference and Workshop Presentations:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Louisiana State Bar Association, Public Utility Section, 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)

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

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

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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

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

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351.	U-31196 (ITA Phase) February 2010	Entergy Louisiana	Louisiana	Staff	Purchase Power Contract
352.	ER09080668 March 2010	Rockland Electric	New Jersey	Rate Counsel	Rate of Return