BEFORE THE CORPORATION COMMISSION

OF THE STATE OF KANSAS

IN THE MATTER OF THE APPLICATION	]	
OF AQUILA, INC. d/b/a AQUILA	]	KCC Docket No. 07-AQLG-431-RTS
NETWORKS-KGO, FOR APPROVAL	]	
OF THE COMMISSION TO MAKE	]	
CERTAIN CHANGES IN ITS RATES FOR	]	
NATURAL GAS SERVICE	]	

DIRECT TESTIMONY OF

ANDREA C. CRANE

RE: REVENUE REQUIREMENTS

ON BEHALF OF

THE CITIZENS' UTILITY RATEPAYER BOARD

March 19, 2007

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I. STATEMENT OF QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Andrea C. Crane and my business address is PO Box 810, One North Main Street, Georgetown, Connecticut 06829.

Q. By whom are you employed and in what capacity?

A. I am Vice President of The Columbia Group, Inc., a financial consulting firm that specializes in utility regulation. In this capacity, I analyze rate filings, prepare expert testimony, and undertake various studies relating to utility rates and regulatory policy. I have held several positions of increasing responsibility since I joined The Columbia Group, Inc. in January 1989.

Q. Please summarize your professional experience in the utility industry.

A. Prior to my association with The Columbia Group, Inc., I held the position of Economic Policy and Analysis Staff Manager for GTE Service Corporation, from December 1987 to January 1989. From June 1982 to September 1987, I was employed by various Bell Atlantic (now Verizon) subsidiaries. While at Bell Atlantic, I held assignments in the Product Management, Treasury, and Regulatory Departments.

Q. Have you previously testified in regulatory proceedings?

A. Yes, since joining The Columbia Group, Inc., I have testified in approximately 250 regulatory proceedings in the states of Arizona, Arkansas, Connecticut, Delaware, Hawaii, Kansas, Kentucky, Maryland, New Jersey, New Mexico, New York, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Vermont, West Virginia and the District of Columbia. These proceedings involved gas, electric, water, wastewater, telephone, solid waste, cable television, and navigation utilities. A list of dockets in which I have filed testimony is included in Appendix A.

Q. What is your educational background?

A. I received a Masters degree in Business Administration, with a concentration in Finance, from Temple University in Philadelphia, Pennsylvania. My undergraduate degree is a B.A. in Chemistry from Temple University.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. On or about November 1, 2006, Aquila, Inc. d/b/a Aquila Networks-KGO ("KGO" or "Company")[1] filed an Application with the State of Kansas Corporation Commission ("KCC" or "Commission") seeking a rate increase of $7.24 million. The requested increase would result in an overall revenue increase of approximately 5.1% and in an increase of approximately 19.2% on non-gas revenues. The Columbia Group, Inc. was engaged by the State of Kansas, Citizens' Utility Ratepayer Board ("CURB") to review the Company's

1 The corporate entity, Aquila, Inc., will be referred to in this testimony as "Aquila".

Application and to provide recommendations to the KCC regarding the Company's revenue requirement claim. Our analysis of the Company's revenue requirement included an analysis of its required cost of capital. Brian Kalcic is also filing testimony on behalf of CURB addressing certain rate design proposals made by KGO.

Q. What are the most significant issues in this rate proceeding?

A. The most significant accounting issues are 1) the impact on KGO of Aquila's sale of certain gas and electric properties; 2) increased payroll costs including incentive and other salary-related adjustments; 3) increased costs for employee benefits; and 4) increases to utility plant-in-service. The Company is also proposing to implement demand side management programs, the costs of which would be recovered from ratepayers through a rate rider.

Q. What impact has Aquila's recent utility sales had on the costs being claimed in this case?

A. In March 2005, Aquila announced a "repositioning strategy" that included the potential sale of certain gas, electric, and non-utility properties. In September 2005, Aquila announced that it had reached agreement to sell its natural gas properties in Michigan, Minnesota, and Missouri as well as its Kansas electric properties. The sale of the gas properties took place in April through June, 2006. Aquila received approval for the sale of its Kansas electric properties in February 2007 and that sale is expected to close shortly.

While Aquila has taken steps to reduce its central support function costs and corporate services costs as a result of these sales, the Company has not been able to eliminate the impact of these sales completely. According to the testimony of Mr. Loomis, approximately $42.3 million of costs for corporate support functions and corporate services was previously allocated to the utilities being sold. Aquila has reduced its central support and corporate services costs by approximately $37.5 million of this amount. However, approximately $4.8 million of costs that were previously allocated to utilities that have been sold will be reallocated to the remaining Aquila customers, including the customers of KGO. The costs allocated to KGO relating to central services functions and corporate support would be expected to increase by approximately 10% as a result of these utility sales.

Q. Do these costs constitute negative merger savings?

A. Yes, they do. In the recently conducted proceeding regarding the proposed sale of the WPK properties to Mid-Kansas Electric Company, LLC ("MKEC"), the KCC was primarily examining the impact of the transaction on the customers of WPK and MKEC. However, as discussed in that case, the sale also resulted in increased costs for the remaining Aquila customers. Moreover, Aquila's remaining customers faced increased costs not only from the fact that certain corporate overhead costs will be now be spread over a smaller customer base, but also due to the fact that electric and gas service will no longer be provided by a common entity. For example, in the current filing, KGO has included adjustments relating to incremental postage and meter reading costs. These are examples of costs that previously benefited from being shared between gas and electric operations. With the sale of certain utilities, these benefits are gone and the remaining ratepayers will be penalized as a result of the sale.

Q. Did you make any disallowances in your testimony to mitigate the impact of these cost increases on KGO customers?

A. No, I did not make any specific adjustments relating to the additional costs that result from the sale of certain utility properties. However, the KCC should be mindful of these additional costs, and their impact on ratepayers, as it evaluates the Company's proposed rate request.

Q. Will the KCC soon be asked to examine another transaction involving the sale of Aquila properties?

A. Yes, it will. On February 7, 2007, Aquila announced that Great Plains Energy, the parent company of Kansas City Power and Light Company, will acquire all of the outstanding shares of Aquila, along with its Missouri-based electric assets. Immediately prior to that acquisition, Black Hills Corporation will acquire from Aquila its gas utilities in Colorado, Kansas, Nebraska, and Iowa along with its electric utility in Colorado. The Company has not yet filed for approval of these proposed transactions with the KCC, and the impact of these transactions is not reflected in the Company's filing or in my testimony. However, this transaction will once again change the level of overhead costs allocated to KGO. In addition, it will result in a new operational structure and organizational environment. At the present time, I cannot estimate the impact of this future transaction on KGO's cost of service, assuming that the sale is approved. However, this issue should be examined by the KCC, and other parties, as part of the review of the proposed KGO sale to Black Hills Corporation. The goal of the KCC should be to use every effort to hold KGO customers harmless from cost increases resulting from restructuring activities.

III. SUMMARY OF CONCLUSIONS

Q. What are your conclusions concerning the Company's revenue requirement and its need for rate relief?

A. Based on my analysis of the Company's filing and other documentation in this case, my conclusions are as follows:

1. The twelve months ending June 30, 2006, as adjusted herein, is an acceptable test year to use in this case to evaluate the reasonableness of the Company's claim.
2. I recommend that the Commission adopt a pro forma capital structure for KGO that consists of 50.7% common equity and 49.3% long-term debt.[2] This is the capital structure proposed by KGO (see Schedule ACC-2).
3. The Company has pro forma debt costs of 7.13% for long-term debt, which is the cost of debt claimed by KGO in its filing (see Schedule ACC-2).

2 Schedules ACC-1, ACC-32, and ACC-33 are summary schedules, ACC-2 to ACC-7 are cost of capital schedules, ACC-8 to ACC-12 are rate base schedules, and ACC-13 to ACC-31 are operating income schedules.

4. The Company has a pro forma cost of common equity of 9.35% (see Schedule ACC-3).

5. Based on my recommended capital structure and capital cost rates, I recommend that the Commission adopt an overall cost of capital of 8.26% for KGO (see Schedule ACC-2).

6. If the KCC approves a rate design that significantly reduces the Company's risk, then a reduction to return on equity would be appropriate. If all revenue risk is eliminated, then return on equity should be reduced by 50% of the difference between my recommended cost of equity of 9.35% and the Company's cost of debt of 7.13%.

7. KGO has test year pro forma rate base of $81,777,155 (see Schedule ACC-8).

8. The Company has pro forma operating income at present rates of $4,669,948 (see Schedule ACC-13).

9. KGO has a test year, pro forma, revenue requirement deficiency of $3,455,996 (see Schedule ACC-1). This is in contrast to the Company's claimed deficiency of $7,240,218.

10. The CURB Board is not opposed to the Company's request to implement a Demand Side Management ("DSM") Rider to recover the costs of certain energy efficiency programs, provided that the costs are reasonable and the overall programs are appropriate. CURB supports the proposed initial DSM rate, which should be shown as a separate line item on customers' bills. CURB supports the Company's plans to offer space and water heating equipment rebates, but has concerns about the proposed

funding for the low-income weatherization program. CURB recommends that the parties work together to determine if there are other DSM programs that may be preferable and provide greater net benefits to the overall customer base.

IV. COST OF CAPITAL AND CAPITAL STRUCTURE

Q. What is the cost of capital and capital structure that the Company is requesting in this case?

A. The Company has utilized the following capital structure and cost of capital:

	Percentage	Cost Rate	Weighted Cost
Long-Term Debt	49.27%	7.13%	3.51%
Common Equity	50.73%	12.00%	6.09%
Total			9.60%

A. Capital Structure

Q. How did the Company determine its capital structure?

A. KGO's claimed capital structure is based on an assignment of capital from Aquila, Inc., the corporate entity that actually issues all debt and equity. According to the testimony of Mr. Murry at page 13, he "only included components of capital in the capital structure that are part of the permanent capital that supports physical utility assets providing utility services currently and during the period that the rates set in this proceeding will be in effect."

Q. Does KGO issue its own debt or equity?

A. No. KGO is not a distinct corporate entity and no common equity is issued at the KGO level. Nor does KGO issue its own debt. The capital structure that ultimately supports the operations of KGO is the overall capital structure for Aquila, Inc.

In Aquila's last litigated proceeding for its former Kansas electric properties, Docket No. 04-AQLE-1065-RTS, CURB and the KCC Staff both recommended that the KCC use Aquila's consolidated capital structure to develop the pro forma overall cost of capital for the utility. The KCC subsequently agreed that the use of the consolidated capital structure was appropriate. CURB and KCC Staff made similar recommendations in the last KGO case, which was settled by the parties.

Q. Are you recommending any adjustment to Aquila's pro forma capital structure in this case?

A. No, I am not. While I continue to disagree with the methodology used by Aquila to develop its pro forma capital structure, the end result appears reasonable. In response to CURB-78, KGO stated that its consolidated debt ratio had declined from 58.3% at June 30, 2006 to 52.3% at September 30, 2006. In addition, in CURB-93, the Company was asked to provide "the Company's projected capital structure for Aquila, total company, once the WPK properties are sold". The Company responded that it was projecting a capital structure consisting of between 42.9% and 46.9% debt, although the actual capital structure "is dependent on the final execution of the debt reduction and credit improvement strategies...".

The KCC has now approved the sale of the WPK properties and the transaction is expected to close shortly. Given the actual improvement in the capital structure that has occurred since the end of the test year, and the further improvement anticipated in 2007, I believe that the pro forma capital structure claimed by KGO represents a reasonable proxy for the expected consolidated Aquila capital structure.[3]

B. Cost of Debt

Q. Are you recommending any adjustments to the Company's cost of debt claim?

A. No, I have accepted KGO's claimed cost of debt of 7.13%. This cost of debt is included in my recommended overall cost of capital, shown in Schedule ACC-2.

C. Cost of Equity

Q. What is the cost of equity that the Company is requesting in this case?

A. KGO is requesting a cost of equity of 12.0%.

Q. Are you recommending any adjustment to the Company's proposed cost of equity?

A. Yes, I am recommending an adjustment to the Company's proposed cost of equity. Specifically, I am recommending that the Commission adopt a cost of equity of 9.35% for KGO.

3 My recommendation does not include the impact of the potential sale of KGO to Black Hills Corporation, announced February 7, 2007. The Company has not yet filed for approval of this transaction and I have not included the implications of this sale in my testimony.

Q. How did you develop your cost of equity recommendation?

A. To develop a recommended cost of equity in this case, I utilized both the Discounted Cash Flow ("DCF") methodology as well as the Capital Asset Pricing Model ("CAPM"). It is my understanding that the Commission has traditionally relied upon the DCF methodology for determining cost of equity for a regulated utility and therefore I have given greater weight to my DCF result.

Q. Please describe the DCF methodology.

A. The DCF methodology is the most frequently used method to determine an appropriate return on equity for a regulated utility. The DCF methodology equates a utility's return on equity to the expected dividend yield plus expected future growth for comparable investments. Specifically, this methodology is based on the following formula:

$$\text{Return on Equity} = \frac{D_1}{P_0} + g$$

where "D_1" is the expected dividend, "P_0" is the current stock price, and "g" is the expected growth in dividends.

In order to ensure that the return on equity determined for a particular utility is representative of returns for comparable investments of similar risk, the DCF methodology examines returns for similar companies through the use of a "comparable" or "proxy" group. To minimize further controversy, I utilized the same companies in my comparable group as those used by Company Witness Donald Murry in his testimony.

To determine an appropriate dividend yield for comparable companies, i.e., the expected dividend divided by the current price, I calculated the dividend yield of each of the comparable companies under two scenarios. First, I calculated the dividend yield using the average of the stock prices for each company over the past twelve months. The use of a dividend yield using a twelve-month average price mitigates the effect of stock price volatility for any given day. Based on the average stock prices over the past twelve months, and the current dividend for each company, I determined an average dividend yield for the comparable group of 3.63%, as shown in Schedule ACC-5. I also calculated the current dividend yield at February 26, 2007, which showed an average dividend yield for the comparable group of 3.44%, also shown in Schedule ACC-5. Finally, I examined the average dividend yields as reported in the March 2007 AUS Utility Reports, which showed an average dividend yield for gas companies of 2.9%. Based on all of this data, I recommend that a dividend yield of 3.63% be used in the DCF calculation. This dividend yield will be increased by one-half of my recommended growth rate, as determined below, to reflect the fact that the DCF model is prospective and dividend yields may grow over the next year. Increasing the dividend yield by one-half of the prospective growth rate is commonly referred to as the "half-year convention."

Q. How did you determine an appropriate growth rate?

A. The actual growth rate used in the DCF analysis is the dividend growth rate. In spite of the fact that the model is based on dividend growth, it is not uncommon for analysts to examine several growth factors, including growth in earnings, dividends, and book value.

Following are historic five-year and ten-year growth rates for the companies in Dr. Murry's comparable group, as reported by Value Line Investment Survey:

	Past Five Years Earnings	**Past Five Years Dividends**	**Past Five Years Book Value**	**Past Ten Years Earnings**	**Past Ten Years Dividends**	**Past Ten Years Book Value**
LG	4.50%	0.50%	2.50%	2.50%	1.00%	3.00%
NJR	8.00%	3.50%	8.50%	7.50%	3.00%	6.50%
GAS	(3.50%)	3.50%	1.50%	1.00%	4.00%	3.00%
NWN	5.00%	1.00%	3.50%	1.50%	1.00%	4.00%
PNY	5.00%	5.00%	6.50%	5.50%	5.50%	6.50%
SJI	11.50%	2.50%	13.00%	8.00%	1.50%	5.50%
SWX	(0.50%)	-	3.00%	7.50%	0.50%	2.00%
WGL	6.00%	1.50%	3.00%	4.50%	1.50%	4.00%
Average	4.50%	2.50%	5.19%	4.75%	2.25%	4.31%

Over the past five years, growth rates have ranged from 2.50% for dividends to 5.19% for book value. Ten-year growth rates for earnings and dividends have been very close to the five-year growth rates, although the growth rate in book value over the past five years has exceeded the ten-year growth rate, due to the acceleration of investment by the utilities.

The Value Line projected growth rates are also generally above the actual historic growth rates, although in this case the disparity between historic and projected growth rates is not as significant as it is in some proceedings:

	Projected Five Years Earnings	Projected Five Years Dividends	Projected Five Years Book Value
LG	5.00%	2.50%	7.50%
NJR	4.50%	4.50%	8.50%
GAS	4.00%	1.00%	4.50%
NWN	7.00%	4.00%	3.50%
PNY	6.0%	5.50%	3.00%
SJI	7.00%	6.00%	6.00%
SWX	9.00%	-	4.50%
WGL	1.50%	2.00%	3.50%
Average	5.50%	3.64%	5.13%

Based on my review of both historic and projected growth rates, I recommend that a growth rate of 5.5% be utilized. This growth rate is higher than the actual growth rates over the past five or ten years in earnings, dividends or book value. It is also higher than the projected growth rates for dividends or book value, and is equal to the Value Line projected growth rate for earnings.

Q. What are the results of your analysis?

A. My analysis indicates a cost of equity using the DCF methodology of 9.23%, as shown below:

Dividend Yield	3.63%
Growth in Dividend Yield (1/2 X 5.5% X 3.63%)	0.10%
Expected Growth	5.50%
Total	9.23%

Q. Did you also calculate a cost of equity based on the CAPM methodology?

A. Yes, I did.

Q. Please provide a brief description of the CAPM methodology.

A. The CAPM methodology is based on the following formula:

Cost of Equity = Risk Free Rate + Beta (Risk Premium)

or

Cost of Equity = $R_f + B(R_m - R_f)$

The CAPM methodology assumes that the cost of equity is equal to a risk-free rate plus some market-adjusted risk premium. The risk premium is adjusted by Beta, which is a measure of the extent to which an investor can diversify his market risk. The ability to diversify market risk is a measure of the extent to which a particular stock's price changes relative to changes in the overall stock market. Thus, a Beta of 1.00 means that changes in the price of a particular stock can be fully explained by changes in the overall market. A stock with a Beta of 0.60 will exhibit price changes that are only 60% as great as the price changes experienced by the overall market. Utility stocks have traditionally been less volatile than the overall market, i.e., their stock prices do not fluctuate as significantly as the market as a whole, and therefore their Betas have generally been less than 1.0.

Q. How did you calculate the cost of equity using the CAPM?

A. My CAPM analysis is shown in Schedule ACC-7. First, I used a risk-free rate of 4.68% for the yield on long-term U.S. Government bonds, which was the rate at February 28, 2007, per the Statistical Release by the Federal Reserve Board. Over the past year, this rate has ranged from 4.51% to 5.25%. In addition, I used the average Beta for my proxy group, based on the Beta for each company as shown on Dr. Murry's Schedule DAM-23. This resulted in an average Beta of 0.84. Finally, since I am using a long-term U.S. Government bond rate as the risk-free rate, the risk premium that should be used is the historic risk premium of stocks over the rates for long-term government bonds. According to the 2006 Ibbotson Associates' publication, *2006 Yearbook: Stocks, Bonds, Bills, and Inflation*, the risk premium of stocks relative to long-term risk-free rates using geometric mean returns is 6.0%.

Q. What is the difference between a geometric and an arithmetic mean return?

A. An arithmetic mean is a simple average of each year's percentage return. A geometric mean takes compounding into effect. As a result, the arithmetic mean overstates the historic return to investors. For example, suppose an investor starts with $100. In year 1, he makes 100% or $100. He now has $200. In year 2, he loses 50%, or $100. He is now back to $100.

The arithmetic mean of these transactions is 100% - 50% or 50%/ 2 = 25% per year. The geometric mean of these transactions is 0%. In this simple example, it is clear that the geometric mean more appropriately reflects the real return to the investor, who started with $100 and who still has $100 two years later. The use of the arithmetic mean would suggest that the investor should have $156.25 after two years ($100 X 1.25 X 1.25), when in fact the investor actually has considerably less. Therefore, a geometric mean return is a more appropriate measure of the real return to an investor, if it is used as I am using it here, i.e., to develop an historic relationship between long-term risk free rates and market risk premiums. The Company has criticized me in the past for using a geometric, rather than an arithmetic mean return, arguing that the arithmetic mean should be used when estimating future returns. However, in my case, I am not using the mean to develop an expected outcome, I am simply using the mean returns to develop an historic relationship. Therefore, the geometric mean is the appropriate measure, as illustrated in the above example.

Q. What is your recommended cost of equity using a CAPM approach?

A. Given a long-term risk-free rate of 4.68%, a Beta of 0.84, and a risk premium of 6.0%, the CAPM methodology produces a cost of equity of 9.72%, as shown on Schedule ACC-7.

Risk Free Rate + Beta (Risk Premium) = Cost of Equity

4.68% + (0.84 X 6.0%) = 9.72%

Q. Based on your analysis of the DCF and CAPM results, what cost of equity are you recommending in this case?

A. The DCF methodology and the CAPM methodology suggest that a return on equity of 9.23 % to 9.72% would be appropriate. Since I recognize that the Commission has generally relied primarily upon the DCF, I have weighted my results with a 75% weighting for the DCF methodology and a 25% weighting for the CAPM methodology. This results in a cost of equity of 9.35%, as shown below:

DCF Result	9.23% X 75% =	6.92%
CAPM	9.72% X 25% =	2.43%
Total		9.35%

Q. Why is your recommendation substantially lower than the cost of equity recommended by Dr. Murry?

A. My recommendation is substantially lower than Dr. Murry's recommendation because Dr. Murry has largely ignored his own DCF result. Dr. Murry conducted several different DCF analyses. As shown in Schedule DAM-25, the results of his Current Discounted Cash Flow Analyses ranged from 7.49% to 9.99%, for an average of 8.74%. Schedule DAM-25 shows that the average of his 52-Week Discounted Cash Flow Analyses ranged from 7.32% to 10.57%, for an average of 8.95%. Both of these averages are well below my DCF result of 9.23%. Thus, Dr. Murry's recommendation places no reliance upon the DCF, which Dr. Murry himself acknowledges is the most commonly used method for determining cost of equity for a regulated utility.

With regard to his CAPM analysis, Dr. Murry's result is similarly flawed, due to his use of an excessive risk premium of 7.0% and a small company premium of 1.61%.

Q. Has there been recent legislation in Kansas that should be considered by the KCC as it evaluates KGO's cost of equity?

A. Yes, there is. In 2006, legislation was passed that permits natural gas utilities to file for a Gas System Reliability Surcharge ("GSRS") in order to recover the costs of certain plant additions between base rate cases (K.S.A. 2006 Supp. 66-2201 et seq.). While the legislation emphasizes gas safety and reliability projects, the types of capital expenditures that can be recovered through this surcharge mechanism are relatively broad. The cost of capital established in this case will be used to determine the amount of any GSRS approved for KGO until the Company's next base rate case. Therefore, the cost of equity established in this case will not only determine the magnitude of the Company's base rate increase, but will also determine the magnitude of future GSRS imposed on ratepayers.

In addition, the GSRS provides a mechanism that significantly reduces the Company's risk between base rate case filings. Therefore, the GSRS legislation has the effect of lowering the Company's required cost of equity. While I have not made a specific adjustment to cost of equity to account for this reduction in risk, the impact of the GSRS legislation should be considered by the KCC as it determines an appropriate return for KGO.

D. <u>Overall Cost of Capital</u>

Q. What is the overall cost of capital that you are recommending for KGO?

A. I am recommending an overall cost of capital for KGO of 8.26%, based on the following capital structure and cost rates:

	Percentage	Cost Rate	Weighted Cost
Long-Term Debt	49.27%	7.13%	3.51%
Common Equity	50.73%	9.35%	4.74%
Total			8.26%[4]

Q. Does your cost of capital recommendation take into account the change in risk resulting from the Company's proposed rate designs?

A. No, it does not. In this case, the Company is proposing to recover a larger share of its revenue requirement through fixed charges. It is my understanding that KGO is requesting approval of a rate structure that would introduce a demand component for all customer classes. The result of such a rate design would be that the Company's rates would be designed to recover virtually all of its non-gas costs through a combination of the fixed monthly customer charge and the new demand charge. In the alternative, if the KCC does not accept the Company's proposal to implement a demand charge, then KGO has also prepared a proposed rate design that recovers all of its non-gas costs for residential and small commercial customers through a flat rate charge.

Brian Kalcic is providing testimony on behalf of CURB addressing the Company's proposed rate structures. While the examination of the Company's rate structure proposals is outside of the scope of my testimony, either of these proposals will significantly reduce the Company's risk. Since the Company is awarded a return on equity premium, i.e., its return

4 Column doesn't add due to rounding. See Schedule ACC-2.

on equity reflects the fact that equity capital is more risky to the investor than debt capital, this equity risk premium must be adjusted to reflect any action by the KCC that reduces the risk to the Company, and therefore to investors.

Q. If the KCC accepts a rate structure proposal that reduces the Company's risk, what would be the impact on the Company's cost of equity?

A. If a rate structure is adopted that includes either a demand charge or a flat rate charge, then the impact on cost of equity would be significant. These rate structures would greatly reduce or eliminate the Company's single largest risk, i.e., revenue risk. Accordingly, there should be a commensurate reduction to cost of equity.

The amount of any return on equity adjustment related to risk reduction should be commensurate with the amount of risk being eliminated. In the most extreme case, if the KCC adopts a rate structure that removes 100% of the Company's revenue risk, then I recommend that the KCC reduce the equity over debt premium that would otherwise be reflected in rates, by 50%. For example, my revenue requirement recommendation is based on a pro forma cost of debt of 7.13% and on a pro forma cost of equity of 9.35%. If a rate structure is adopted that removes all revenue risk, then I recommend that this differential be reduced by 50%, and that the KCC adopt a cost of equity for KGO of no greater than 8.24%. If a rate structure is adopted that removes some portion, but not all, of the Company's revenue risk, then a proportionate reduction in the equity premium would be appropriate.

V. RATE BASE ISSUES

Q. What test year did the Company utilize to develop its rate base claim in this proceeding?

A. The Company selected the test year ending June 30, 2006.

A. Accumulated Depreciation

Q. Did the Company make any adjustment to its reserve for depreciation at June 30, 2006?

A. Yes, it did. The Company made two adjustments to the reserve for depreciation, totaling $607,699. First, the Company made an adjustment to reflect the difference between the Company's annualized depreciation expense and the test period book expense. Second, the Company made a reserve adjustment to reflect annual depreciation expense resulting from the amortization of deferred depreciation expense associated with corporate assets.

Q. Are you recommending any adjustment to the Company's depreciation reserve claim?

A. Yes, I am recommending one adjustment. I am recommending that the amortization of the deferred depreciation expense be denied. Therefore, it is necessary to eliminate the associated reserve addition from rate base. My adjustment is shown in Schedule ACC-9.

Q. Why are you recommending disallowance of the deferral amortization?

A. I am recommending disallowance because, to my knowledge, the Company has not requested or received approval from the KCC to defer these costs. On page 22 of Mr. Petersen's testimony, he states that a depreciation study relating to corporate assets was conducted in 2003 by Foster and Associates. The study recommended higher depreciation rates for certain assets. According to Mr. Petersen, "...the impact of the higher rates was deferred until Aquila obtained approval of the depreciation rates in each state." Aquila states that its depreciation rates have now been approved and therefore it is proposing to amortize the deferred depreciation expense over a three-year period.

It is inappropriate for the Company to unilaterally defer these costs and now request an amortization without KCC authorization to do so. To now request recovery of these past costs from ratepayers would clearly constitute retroactive ratemaking and should be rejected by the KCC. If KGO intended to implement these depreciation rates prior to their inclusion in utility rates, then it should have requested KCC authorization to defer the costs for future recovery. It did not do so and the Company should not now be permitted to claim recovery of these costs from ratepayers.

Accordingly, I am recommending an adjustment to the Company's reserve for depreciation to eliminate this reserve addition. The effect of my adjustment is to decrease the Company's reserve for depreciation and therefore to increase its rate base claim. My adjustment is shown in Schedule ACC-9. The associated annual depreciation expense adjustment is shown in Schedule ACC-29.

B. Gas in Storage

Q. How did the Company develop its pro forma claim in this case for gas in storage?

A. KGO used a thirteen-month average balance, from June 2005 to June 2006.

Q. Are you recommending any adjustment to the Company's claim?

A. Yes, I am. A review of historic storage levels demonstrates that KGO has significantly increased its storage volumes over the past few years and continues to increase those volumes. It is ironic that the Company is increasing its storage volumes at a time when it also claims that there is little or no growth in customers and that consumption per customer is declining.

Q. How does the Company's claim for gas in storage volumes compare with historic levels?

A. Following are the average monthly storage volumes for each of the past five years:

	Gas in Storage Volumes
Calendar Year 2002	633,541
Calendar Year 2003	673,169
Calendar Year 2004	914,309
Calendar Year 2005	920,647
Test Year	999,383

As shown above, over the past few years, the Company's storage volumes have grown considerably. In the Company's last base rate case, which was based on a test year ending June 30, 2004, I expressed concerns about the significant increase in gas storage volumes. This increase is continuing. The volumes claimed in rate base in this case are 18% higher than the volumes claimed by KGO in the 2004 case.

Q. What do you recommend?

A. KGO has once again failed to justify the significant increase in gas in storage volumes being requested in this case. Therefore, I recommend that the KCC utilize, for this case, gas in storage volumes based on the actual twenty-five month average volumes from June 2004 through June 2006. My adjustment is shown in Schedule ACC-10. It reflects pro forma volumes of gas in storage of 963,775, which is still significantly greater than the volumes in storage over the past few years but more reasonable than the Company's inflated claim. In calculating my adjustment, I have priced these volumes at the average gas cost for the test year of $7.05. My adjustment results in an average of gas in storage of $6,794,614 instead of the $7,050,188 proposed by KGO.

C. Prepayments

Q. How did the Company determine its claim for prepayments?

A. KGO included a thirteen-month average in its filing. The prepayments included by the Company in its rate base claim include prepaid insurance, prepaid pensions, and prepaid gas.

The Company's total rate base claim associated with prepayments is $1,312,321.

Q. Are you recommending any adjustment to the Company's claim?

A. Yes, I am recommending that only prepaid insurance be included in rate base. Only about 28% of the Company's total claim for prepayments relates to prepaid insurance. I am recommending that the KCC deny the Company's claims for inclusion in rate base of the pension asset and prepaid gas.

Q. What is meant by the prepaid pension asset that the Company has included in rate base?

A. A prepaid pension asset is created when annual increases in pension plan assets exceed annual costs associated with pension obligations. Approximately 65% of the Company's claim for prepayments relates to prepaid pension costs.

Q. Do you agree that the pension asset is an appropriate rate base component?

A. No, I do not. In determining the appropriate revenue requirement for a utility, regulatory commissions can quantify a company's pension expense in one of two ways. First, a regulatory commission can base a utility's pension expense on the accrual methodology that is required for financial reporting purposes based on Statement of Financial Accounting Standard ("SFAS") 87. Second, a regulatory commission can base a utility's pension expense on the actual cash contributions made each year to the pension fund. The minimum contributions are determined by a formula developed pursuant to the Employee Retirement Income Security Act ("ERISA"). The maximum contributions are governed by Internal Revenue Service ("IRS") regulations. While I am familiar with regulatory commissions that use each of these approaches (SFAS 87 and the cash funding approach), most commissions, including the KCC, utilize the SFAS 87 methodology to establish a utility's pension expense for the purpose of setting utility rates.

Under SFAS 87, a pension expense can be either positive or negative. If it is positive, then the pension plan in under-funded from an actuarial perspective and ratepayers are required to provide additional funding for the plan. If the pension expense is negative under SFAS 87, then the plan is over-funded and ratepayers receive a credit in cost of service due to the fact that the plan recovered more from ratepayers than was necessary in prior years.

Q. How is the SFAS 87 expense determined?

A. The expense is determined based on numerous assumptions designed to reflect the very long-term nature of pension obligation and the present value of those obligations. The long-term view also includes an assumption regarding the performance of the assets set aside in the pension trust, as the earnings on those assets will be available to meet the obligations of the pension plan. SFAS 87 was designed to smooth the volatility associated with the changes in the market value of the assets as measured at a particular point in time and to recognize such changes systematically and gradually over subsequent periods.

Q. Do you believe the SFAS 87 expense is superior to the cash method for determining pension expense in rates?

A. I am indifferent as to whether a regulatory commission uses SFAS 87 or the cash methodology, although I recognize that a utility has significant control over the actual cash contributions and could therefore manipulate its funding in years when rate cases are filed. However, I do believe that it is important for regulatory commissions to be consistent in their choice of methodology. In neither case should a pension asset be included in rate base.

It is clear that SFAS 87 was adopted for ratemaking purposes and has been utilized for many years. There will be years pursuant to SFAS 87 reporting when such ratemaking expense exceeds the Company's actual cash contribution and there will be years when the expense is less than the Company's contribution. Over time, the discrepancies between contributions and expenses even out. Given the annual fluctuations due to changes in assumptions, market value, and other factors, it is important for regulatory commissions to consistently use either the SFAS 87 method or the cash funding approach.

Q. Do you agree that a prepaid pension asset belongs in rate base?

A. No, I do not. The Company has based its ratemaking claim in this case on its SFAS 87 expense, not on cash contributions made to the fund. The pension asset is an actuarially-determined amount but it has no application to utility ratemaking. The pension asset is impacted not only by contributions that a company makes but also by earnings on the pension fund. The pension asset grew from 1991 to 2001 because the SFAS 87 expense was negative, not because the Company made cash contributions. The pension asset is now declining, as the SFAS 87 expense becomes positive.

Moreover, it is the Company that largely controls the amount and timing of its contributions to the plan and could manipulate contributions in rate case years. KGO has not shown that the contributions made during the past few years were required under ERISA. It must be noted that the pension asset does not reflect the difference between the amount of funding provided by ratepayers and the amount of pension expense incurred by KGO. Thus, there is no ratemaking nexus between the prepaid pension asset and utility rates.

Q. Do you believe the actual cash funding of the pension fund should affect the ratemaking treatment of pension expense?

A. No. As previously stated, regulatory commissions can determine pension expense for ratemaking purposes in one of two ways. If the regulatory commission uses the cash methodology to set rates, then obviously the ratemaking allowance should be based on actual cash contributions made to the plan. However, if the regulatory commission sets rates using the SFAS 87 methodology, then utility rates should be unaffected by the actual amount of pension funding. The funding decision at a given point in time is almost entirely within a company's control as long as it falls between the minimum funding level specified under ERISA and the maximum tax-deductible contribution.

It is the consistency of using the SFAS 87 expense for ratemaking that assures, over the life of the plan, that the expense recognition and the contributions to the plan will be equal.

Q. Does the current prepaid asset represent funding provided by the Company in excess of expenses it has recovered in rates?

A. No. The pension asset is impacted by the Company's ratemaking treatment and the amount collected in rates has no bearing on the quantification of the pension asset. Therefore, the pension asset does not represent amounts funded by investors over and above those amounts recovered from ratepayers. Once again, there is no direct link between the prepaid pension asset and amounts collected from ratepayers.

Q. When did Aquila first request inclusion of a pension asset in rate base?

A. Although Aquila adopted SFAS 87 in 1987, it appears that Aquila did not request inclusion of a pension asset in rate base until its last electric case, KCC Docket No. 04-AQLE-1065-RTS. While I understand that the rates established in that case included a pension asset in rate base, it appears that the KCC did not explicitly address the issue of the pension asset in its Order in that case. The Company also requested a pension asset in its last gas base rate case, KCC Docket No. 05-AQLE-367-RTS. That case was settled pursuant to a "black box" settlement that did not address the specific ratemaking treatment for the Company's claimed pension asset.

Q. Has the KCC addressed other pension-related issues in the interim?

A. Yes, it has. On October 17, 2006, a Joint Petition was filed by Atmos Energy Corporation, Aquila, Inc. d/b/a Aquila Networks-KGO, the Empire District Electric Company, Kansas City Power and Light Company, and Westar Energy, Inc. (collectively "Joint Petitioners"), requesting certain Accounting Authority Orders ("AAO") relating to implementation of SFAS 158. The Joint Petitioners requested that the KCC approve one or more mechanisms to facilitate the implementation of SFAS 158 and to provide other rate relief relating to pension and other post-employment benefit ("OPEB") costs. Specifically, the Joint Petitioners requested that they be permitted to implement, at their option, one or more of the following:

(1) an AAO to establish regulatory assets or regulatory liabilities to track the difference between pension, post-retirement, and post-employment expenses actually incurred and recovered in rates, between rate cases;

(2) an AAO to recognize, for ratemaking purposes, any charges recorded against equity in compliance with SFAS 158, either through the establishment of a regulatory asset or through an adjustment to the equity percentage in their utility's capital structure; and

(3) an AAO to recognize for ratemaking purposes contributions to their pension, post-retirement, and post-employment plans that are in excess of plan expenses.

On January 24, 2007, the KCC issued an order authorizing the Petitioners to recognize, for ratemaking purposes, any charges recorded against equity in compliance with SFAS 158, either through the establishment of a regulatory asset or through an adjustment to the equity percentage in the utility's capital structure. The KCC denied the Petitioners' other two requests, and instead stated that a generic docket would be opened to address the other two proposals. It should be noted that the action taken by the KCC with regard to the equity issue raised in item 2, above, does not result in the inclusion of a pension asset in rate base. The other two issues, which could have impacted a pension asset, were specifically not approved by the KCC and instead were deferred to a future generic docket.

The fact is that the KCC never directly addressed KGO's proposal to include the pension asset in rate base. A review of the KCC's order in the earlier electric case indicates that the there was no discussion of the pension asset issue in that decision. Moreover, the KCC has expressed its intent to open a generic docket to discuss the appropriate ratemaking treatment for various pension costs. Accordingly, for all these reasons, I continue to recommend that the pension asset be excluded from rate base. Therefore, I have not included the pension asset in the prepayments that I included in my rate base recommendation.

Q. Are you also recommending that the Company's prepaid gas be excluded from the prepayments included in rate base by KGO?

A. Yes, I am. The Company has included in prepayments one month of a prepaid gas balance in the amount of $1,237,628. Thus, not only is Aquila's gas in storage balance excessive, due to a significant increase in gas volumes, but in addition to the volumes included in its gas in storage claim, additional volumes are implicitly included in rate base through the Company's claim for prepayments.

Q. In addition to your concerns expressed above with regard to the volume of gas in storage, is there another reason why this gas prepayment should be excluded from rate base?

A. Yes, there is. KGO has consistently taken the position that it is holding ratepayers harmless from the effects of its low credit rating, including the requirement that it prepay for certain gas. In fact, on page 7 of Mr. Loomis's testimony, he states that "Aquila has also excluded the cost, if any, associated with prepay arrangements in gas procurement. These include any costs associated with any premium paid for gas purchases and any working capital impact." However, the Company is now proposing to include in rate base prepayments relating to a gas contract, in addition to a significant increase in actual volumes of gas in storage.

I have already discussed my recommendation to utilize a twenty-four month average of storage volumes to develop the pro forma gas in storage balance that should be included in rate base. I am recommending that amounts over this average be eliminated from rate base, whether such amounts are shown by KGO as gas-in-storage or as prepayments. Thus, in Schedule ACC-11, I have included prepayments that only reflect the Company's prepaid insurance balances. The prepaid pension asset and prepaid gas amounts have been excluded in my recommendation.

D. Cash Working Capital

Q. What is cash working capital?

A. Cash working capital is the amount of cash that is required by a utility in order to cover cash outflows between the time that revenues are received from customers and the time that expenses must be paid. For example, assume that a utility bills its customers monthly and that it receives monthly revenues approximately 30 days after the midpoint of the date that service is provided. If the Company pays its employees weekly, it will have a need for cash prior to receiving the monthly revenue stream. If, on the other hand, the Company pays its interest expense quarterly, it will receive these revenues well in advance of needing the funds to pay interest expense.

Q. Do companies always have a positive cash working capital requirement?

A. No, they do not. The actual amount and timing of cash flows dictate whether or not a utility requires a cash working capital allowance. Therefore, one should examine actual cash flows through a lead/lag study in order to accurately measure a utility's need for cash working capital.

Q. Did the Company prepare a lead/lag study in this case?

A. No, it did not. In this case, KGO used the "one-eighth" formula method, resulting in a cash working capital claim of $3.0 million. The Company then made some additional adjustments to reflect the working capital provided by accrued taxes and interest, resulting in a net cash working capital claim of $700,517.

Q. Are you recommending any adjustments to the Company's cash working capital claim?

A. Yes, I am recommending that the Company's cash working capital requirement be set at $0.

Q. What is the basis for you recommendation?

A. Aquila has repeatedly indicated that it intends to shield ratepayers from any negative effects of its credit problems. In the absence of a requirement to pre-pay for its gas purchases, the evidence suggests that Aquila's cash working capital requirement would be negative. The last lead/lag study undertaken for KGO's operations was provided in Docket No. 00-UTCG-336-RTS. In that case, the Company claimed a negative cash working capital requirement of ($822,626). Moreover, in the Company's last electric base rate case, Docket No. 04-AQLE-1065-RTS, Aquila also filed a lead/lag study that resulted in a negative cash working capital requirement. KGO did not provide a lead/lag study in its last gas base rate case.

Given the fact that the Company filed a negative cash working capital claim in the last gas base rate case for which a lead/lag study was provided, and given the negative cash working capital requirement filed in the last electric case, there is ample evidence to suggest that a lead/lag study performed for the gas utility, when adjusted to eliminate the negative impact of Aquila's financial difficulties, would also result in a negative cash working capital requirement. However, as previously stated, the 1/8th formula method used by KGO in its filing will never yield a negative result because it does not address specific cash flows. While I understand that some regulatory commissions have accepted the use of the formula method in certain cases, that method should be rejected here, given substantial evidence that the Company's cash working capital requirement is negative. Accordingly, at Schedule ACC- 12, I have made an adjustment to reflect a $0 cash working capital requirement.

E. Summary of Rate Base Issues

Q. What is the impact of all of your rate base adjustments?

A. My recommended adjustments reduce the Company's rate base claim from $83,610,994, as reflected in its filing, to $81,777,155, as summarized on Schedule ACC-8.

VI. OPERATING INCOME ISSUES

A. Pro Forma Revenues

Q. Are you recommending any adjustments to the Company's pro forma revenue claim?

A. Yes, I am recommending one adjustment to the Company's pro forma revenue claim. Specifically, I am recommending an adjustment to annualize residential customers.

Q. Why didn't the Company propose a revenue annualization adjustment in this case?

A. According to the response to CURB-15, the Company considered it "unnecessary". In that response, Aquila stated that "[a]n adjustment to annualize numbers of customers is usually problematic because numbers of customers normally fluctuate from month to month." The Company also stated that it did not annualize customers because "[i]n order to reflect annualized customers at the end of the test year period, the Company's rate base and expenses would need to be in sync with such an adjustment."

Q. Do you agree with the Company that a customer annualization adjustment is "problematic"?

A. No, I do not. A review of the customer counts provided in Schedule 8 of the Company's filing shows that end of year residential customers have increased consistently over the past five years, as shown below:

Dec. 31, 2003	91,515
Dec. 31, 2004	92,528
June 30, 2005	93,170
December 31, 2005	93,577
June 30, 2006	94,010

Thus, for residential customers, the trend has clearly been up, although there could be variations from month-to-month. During the twelve months ending June 30, 2006, residential customers grew by 840 customers. However, only one-half of this growth is reflected in the Company's filing, which is based on actual average customers during the test year. Since the historic data clearly shows a trend toward positive customer growth in the residential sector, KGO should have included a pro forma adjustment to annualize customers at the end of the test year.

Q. Please comment on the Company's claim that rate base and expenses would also have to be synchronized if customers were annualized at year-end levels.

A. The Company has already reflected a year-end plant-in-service balance in its rate base claim, providing further support for my recommendation that customers also be annualized at year-end levels. In fact, the Company has used year-end, rather than average test year, balances for the majority of its rate base components. The Company correctly notes that it did not use year-end balances for a few rate base components, such as materials and supplies and gas in storage. But the rationale for using average balances for these components is that they fluctuate significantly throughout the year. An average for materials and supplies and prepayments is used in order to mitigate the impact of these fluctuations, not because these averages represent the investment needed to serve customers at the midpoint of the test year. In addition, KGO has made numerous expense adjustments to reflect pro forma prospective costs. Therefore, the Company's rationale that an annualization adjustment would not be synchronized with its rate base and expense claims is without merit. I therefore recommend that the KCC adopt an annualization adjustment for residential customers.

Q. How did you calculate your proposed annualization adjustment?

A. My proposed adjustment was calculated in a very straightforward, and conservative manner. First, I calculated the growth in customers from June 30, 2005 to June 30, 2006, which was 840 residential customers. Since only one-half of these customers are, on average, included in the Company's claim, I adjusted the Company's margin to reflect an additional 420 customers. To determine the total incremental sales and margins, I relied upon the weather normalization consumption and margin per therm developed in Ms. Winslow's testimony.

Q. Did you also include customer charge revenue in your adjustment?

A. Yes, I did. However, in calculating my pro forma revenue adjustment, I included only $10.00 per month of customer charge revenue, instead of the entire $12.00 current customer charge rate. My decision to reflect only $10 of monthly customer charge revenue reflects the fact that the Company will incur some incremental fixed costs to serve new customers, such as billing and postage costs. My adjustment assumes that these incremental costs will be no greater than $2.00 per customer per month. Therefore, I included only $10.00 per month of incremental customer charge revenue in my adjustment. My adjustment is shown in Schedule ACC-14.

B. <u>Salaries and Wages</u>

Q. How did the Company develop its salary and wage claim in this case?

A. KGO made several adjustments to its salary and wage claim. Out of total operating expense adjustments of $1.32 million, the vast majority of the dollars involved relate to payroll or other personnel-related costs. For example, the Company's claim includes the following personnel-related adjustments:

Payroll Annualization	$1,164,766
Merit and Contract Increment	$410,685
Variable Compensation Plan	$221,611
Range Penetration	$145,862
Total	$1,942,924

Thus, all other operating expense adjustments made by KGO actually net out to a reduction in operating expense.

In Adjustment No. 6, KGO made an adjustment to annualize salaries and wages at August 15, 2006. This annualization includes costs, at August 2006 salary and wage levels, for a full complement of projected employees, including costs for positions that were vacant as of that date. In addition, Adjustment No. 6 includes associated "Other Payroll" costs, such as costs for overtime, standby, double time, and call out costs. Adjustment No. 6 also includes the annualized incentive payroll costs associated with the August 2006 annualized payroll, and an adjustment to Other Benefits Expense, which will be addressed later in this testimony.

In Adjustment No. 12, KGO made another payroll adjustment to reflect union and non-union contractual and merit increases taking place subsequent to August 15. This adjustment includes a 3% non-union increase effective March 2007, and union increases ranging from 3.0% to 3.21% effective from October 28, 2006 to April 1, 2007. Adjustment No. 12 also includes an associated adjustment to Other Benefits Expense.

Adjustment No. 14 includes increases relating to the Company's Variable Compensation Plan. Finally, Adjustment No. 22 reflects "range penetration" adjustments for specific Aquila employees.

Q. Are you recommending any adjustment to the Company's payroll expense claim?

A. Yes, I am recommending several adjustments. First, I am recommending that costs associated with vacant positions be eliminated. Second, I am recommending that the range penetration increases be disallowed. Finally, I am recommending that the increases to the variable incentive plan benefits be rejected.

Q. Please discuss your recommended adjustments with regard to vacant employee positions.

A. The Company included KGO payroll costs of $199,096 for vacant positions in its claim. This claim includes vacant positions at KGO as well as vacant positions in other departments that are allocated, in part, to KGO.

It is normal and customary for companies to have unfilled positions at any given time as a result of terminations, transfers, and retirements. If utility rates are set based on a full complement of employees, and if these employee positions remain vacant, then ratepayers will have paid rates that are higher than necessary, to the benefit of shareholders. Therefore, when setting rates, I recommend that the Commission consider the fact that, at any given time, positions are likely to be vacant.

Q. How did you quantify your adjustment?

A. As shown in the Company's workpapers, there was a total of $951,655 in vacant positions at August 15, 2006. For each vacant position, I determined the percentage of costs allocated to the Kansas gas jurisdiction. The total salaries and wages for vacant positions allocated to the Kansas jurisdiction was $199,096. I then reduced this amount by the percentage of salaries and wages capitalized. My resulting adjustment, which is shown in Schedule ACC-15, reduces the Company's salary and wage claim by $154,578.

Q. Did you make a corresponding adjustment to the Company's incentive cost claim?

A. Yes, I did. The Company's claim shown in Adjustment No. 6 includes incentive costs of approximately 4.1% of payroll. Therefore, I increased my recommended disallowance by 4.1% of my recommended salary and wage adjustment, less capitalized costs, to eliminate the incentive costs associated with vacancies. This incentive expense adjustment is also shown in Schedule ACC-15.

Q. Does your recommended revenue requirement include <u>any</u> positions that were vacant in August 2006?

A. Yes, it does. In addition to its salary and wage adjustments, KGO also included payroll costs and related loadings for certain new meter reading positions in Adjustment No. 19. These positions were formerly shared between gas and electric operations. Once the Kansas electric sale is complete, these positions will need to be filled in order to meet the needs of the Kansas natural gas customers. I have included costs for these vacant positions in my revenue requirement recommendation.

Q. What adjustment are you recommending to the Company's contract and merit payroll adjustment (Adjustment No. 12)?

A. The only merit payroll adjustment that I am recommending to the Company's claim is to eliminate the merit increases associated with my vacancy adjustment, discussed above. All of the vacancies discussed above are non-union positions and the Company included a 3.0% merit increase for non-union employees in its filing. Therefore, at Schedule ACC-16, I have made an adjustment to eliminate $4,637 of merit increases, which is 3.0% of my recommended salary and wage expense adjustment related to vacancies.

Q. Please describe the Company's proposed range penetration adjustment.

A. Aquila included an adjustment of $110,083 that it claims is related to a "range penetration" adjustment. The Company claims that this adjustment was necessary because certain employees "were being paid below the relevant market rate for their job."[5] The Company also included an associated Other Benefits Expense adjustment in its range penetration adjustment.

Q. Do you believe that the Company's claim is reasonable?

A. No, I do not. According to the response to CURB-26, Aquila's non-union employees have received salary and wage increases totaling 9.7% since 2004. The Company did not provide any documentation to suggest that these increases were insufficient to attract employees. The Company's adjustment was apparently not based on any Aquila-specific experience, but rather was based on various (confidential) salary studies performed by industry and trade associations. Aquila's range penetration adjustment was apparently an attempt to reach the median of these salary benchmarks. But these benchmark surveys were not exclusive to the workforce market for Aquila. Nor is there any evidence to suggest that achieving the median on any of these benchmarks was either necessary or desirable, except to the individual employees that received salary treatment. Aquila has failed to demonstrate why these additional adjustments were necessary for the provision of safe and adequate utility service and I recommend that such adjustments be disallowed in this case. My adjustment is shown in Schedule ACC-17.

5 Testimony of Terry R. Thomas, page 5.

Q. What adjustment did the Company propose to its variable compensation plan costs?

A. Aquila has increased these costs by 50% over the actual test year costs. This is based on the Company's decision to double the compensation targets under the variable plan.

Q. Did Aquila discuss why it believed that this increase was necessary?

A. No, there is no discussion in the Company's testimony as to why this 50% increase was necessary. In documentation provided in discovery, the Company indicated that the increase was provided "[i]n an effort to better recognize employee dedication to the business and to bring target opportunities closer to market...."[6] However, there is no evidence that these expanded incentives were needed to attract employees, to retain employees, or to compete in any particular market. Moreover, there is no assurance that the 50% increase in plan benefits will be retained in the future. In fact, the parameters of the plan that were provided in discovery addressed only the 2006 plan year, which is paid out in early 2007, and these parameters are subject to change in the future. I am not recommending any adjustment to the test year costs for the incentive plan awards, but clearly the Company has not demonstrated why it needed to double the benefits under the plan subsequent to the test year.

Q. Didn't you recommend an adjustment to Aquila's incentive cost claim in the Company's last electric base rate case?

A. Yes, I did. In that case, I recommended disallowance of 25% of Aquila's incentive costs, on

6 Response to CURB-33.

the basis that 25% of the incentive costs related to the fulfillment of financial goals that provided no direct benefit to ratepayers. The KCC did not address my specific recommendation in its Order, finding only that "[t]he Commission can see value, under the right circumstances, in using incentive pay as a means for utility management to promote the achievement of certain operational goals."[7] While I was disappointed that the KCC did not address my specific recommendation, I did not propose a similar adjustment in the Company's last gas base rate case, given the decision in the electric proceeding. However, now the Company is pushing the KCC's decision even further, doubling the proposed variable compensation plan benefits. Therefore, while I am not proposing any adjustment to the Company's test year variable compensation plan costs, I find that the Company has not justified the 50% increase in benefits being proposed in this case. Accordingly, I have made an adjustment at Schedule ACC-18 to eliminate the Company's proposed cost increase associated with the change in plan benefits.

Q. What adjustment have you made to the Company's payroll tax expense claim?

A. Since I am recommending a reduction to the Company's payroll costs and its incentive plan costs, it is necessary to make a corresponding adjustment to eliminate certain payroll taxes. At Schedule ACC-19, I have made an adjustment to eliminate payroll taxes associated with my recommended payroll and incentive award adjustments, using the statutory payroll tax rate of 7.65%.

7 Order on Application, January 16, 2004, Docket No. 04-AQLE-1065-RTS, paragraph 36.

C. Other Benefits Expense

Q. Are you also recommending elimination of certain Other Benefit Expenses that the Company included in Adjustment Nos. 6, 12, and 22?

A. Yes, I am. The Company included adjustments relating to Other Benefits Expense in its adjustments relating to payroll annualization (Adjustment No. 6), contract and merit increases (Adjustment No. 12), and range penetration (Adjustment No. 22). Thus, the Company has assumed that its proposed payroll increases will have a direct impact on Other Benefits Expense, increasing these costs by a corresponding amount.

Q. Do you agree with the Company's adjustment?

A. No, I do not. A review of the costs included in the Other Benefits Expense adjustments indicates that many of these costs are the subject of separate adjustments made by the Company while others do not necessarily fluctuate in direct proportion to changes in payroll expense. For example, I understand that health and dental insurance costs, pension costs, and other-post retirement benefits costs, all of which are the subject of separate and distinct adjustments also made by KGO, are included in the Other Benefits Expense adjustments. Therefore, including these adjustments as part of the payroll and incentive award adjustments, as well as in stand-alone adjustments elsewhere in the filing, results in a double counting of costs.

Another flaw with the Company's methodology is that certain remaining costs included in Other Benefits Expense do not necessarily fluctuate directly with payroll costs. For example, relocation costs, educational reimbursement costs, employee gifts and awards, and adoption assistance are all examples of costs that do not necessarily fluctuate in direct proportion to payroll. Since the Company has included costs in Other Benefits Expense that do not fluctuate with payroll increases, as well as costs that are the subject of separate, stand-alone adjustments, I recommend that the Company's Other Benefits Expense adjustments included in its payroll and incentive award adjustments be rejected.

Q. How did you quantify your recommendation?

A. I have eliminated the Company's claimed Other Benefits Expense adjustments included in KGO Adjustment Nos. 6, 12, and 22. My adjustment is shown in Schedule ACC-20.

Q. Is it possible that there are certain cost increases included in Other Benefits Expense that should be accepted by the KCC?

A. Yes, it is possible that a portion of the adjustments claimed by KGO do vary in direct proportion to payroll costs. If so, then I have no objection to the KCC reflecting these incremental costs in utility rates. However, at this time, KGO has not provided any support to demonstrate a direct relationship between payroll costs and any of these Other Benefits Expenses. If the Company provides specific evidence to demonstrate that certain costs included in its Other Benefits Expense adjustments vary in direct proportion to payroll costs, then I would recommend that those legitimate costs that are adequately supported by the Company be included in KGO's revenue requirement. However, at this time, I am unable to recommend inclusion in the Company's revenue requirement of any of the costs shown in the Other Benefits Expense adjustments.

D. <u>Health Care Costs</u>

Q. How did the Company develop its health care cost claim in this case?

A. There appears to be conflicting information on that issue. In her testimony, Ms. Gustin states at page 3, lines 20-21, "Aquila's medical plan rate increase for active employees in 2007 will be 14.8%." However, the workpapers provided for Adjustment No. 9, show that the Company's test year medical costs were inflated by 29.9% to develop the pro forma costs claimed in this case. To add to the contradictions, the Company states that over the past five years, medical costs have increased by 10% annually. The Company does not explain why it believes that a projected increase of 14.8% is reasonable, or why its actual increase is almost 30% over the test year costs.

Q. Is the Company self-insured for its health care costs?

A. I understand that the Company is self-insured for the most significant component of its health care costs, i.e., its medical insurance. Its dental plan is also self-insured. The Company does have small vision and HMO plans that are insured by third party insurers, but these are minor components of its costs.

Q. Has Aquila justified its requested increase in health care costs?

A. No, it has not. Not only has the Company provided conflicting information about its health care cost claim, but in addition it is requesting an increase that is significantly higher than its actual experience over the past five years.

Q. What do you recommend?

A. Based on the provision of conflicting documentation, and on the historic level of cost increases incurred for health care costs, I believe that the Company's request in this case is excessive. Therefore, I recommend that the KCC approve a pro forma health care cost that represents an increase of 10.0% over the actual test year costs allocated to KGO. My recommendation is shown in Schedule ACC-21.

E. Other Post-Employment Benefits ("OPEBs")

Q. How did the Company develop its claim for OPEB costs in this case?

A. The Company's claim was based on the projected 2006 annual expenditure, increased to reflect an additional adjustment of 14.8%, which was the percentage increase assumed for employee medical expenses.

Q. Did the Company subsequently revise its claim for OPEB costs?

A. Yes, it did. In response to CURB-94, the Company stated that its actuary has now finalized its 2007 OBEP liability. The final 2007 OPEB cost reflects a reduction of $86,377 from the amount included in KGO's filing. Therefore, at Schedule ACC-22, I have made an adjustment to update the Company's claimed OPEB costs to reflect the more recent information available from its actuaries.

Q. In developing its revised claim, did Aquila take into account the requirement that it provide additional funding to the Voluntary Employee Beneficiary Association ("VEBA") Trust established for its OPEB liability, as required in Docket No. 06-MKEE-524-ACQ?

A. It is unclear from the documentation provided by Aquila whether this funding requirement was reflected in the revised actuarial report for the Company's OPEB liability, or even if this funding requirement will impact the determination of the liability pursuant to SFAS 106. In the Stipulation in Docket No. 06-MKEE-524-ACQ, Aquila agreed to provide additional funding for the KGO VEBA Trust in an amount equal to the current estimate of its unfunded accumulated OPEB obligation. In addition, it agreed to make an additional contribution to its pension fund. The Company's testimony does not state if these contributions have any impact on its actuarially-determined liabilities, or if any such impacts were reflected in KGO's claim for OPEB and pension costs. I recommend that Aquila provide additional information in its Rebuttal Testimony, stating whether these contributions have been made and if so, what, if any, impact they have on the Company's OPEB and pension cost claims.

F. **Customer Conversion Costs**

Q. Please discuss the Company's claim for customer conversion costs.

A. As described by Mr. Thomas on page 2 of his testimony, "...Aquila was granted an Accounting Authority Order (AAO) to defer and seek recovery of its actual costs incurred to respond to an emergency situation due to hydrogen sulfide levels in natural gas being supplied to a number of customers in southwestern Kansas." According to its workpapers for this adjustment (Adjustment No. 5), the Company incurred these costs from March 2005 through July 2006.

On July 18, 2005, the KCC approved the Company's request and issued an AAO. In its Order approving the Company's request to defer these costs, the KCC found that "[t]he authority granted herein is only for the recording and accumulation of the described costs. No determination is made as to the recoverability of any such cost in any future proceeding. All such issues will be determined at such time as KGO requests recovery of such costs in the context of a rate proceeding." The KCC stated in its Order that "KGO may include carrying charges on the unamortized balance of the H_2S related deferred asset. The carrying charge shall be the authorized rate of return from KGO's last rate case."

Q. How did the Company develop its claim for customer conversion costs in this case?

A. KGO included only incremental, third-party costs in its claim. The Company is not requesting recovery of internal costs relating to customer conversions, since these costs should have already been recovered through base rates. KGO is proposing that it recover carrying costs of 9.60%, which is the overall rate of return that it is requesting in this case. The Company has applied this carrying cost to the unamortized deferral through July 2007. In addition, it has assumed a three-year amortization period, subsequent to July 2007. During the amortization period, it has also applied a carrying cost of 9.60%.

Q. Are you recommending any adjustment to the Company's claim for recovery of these costs?

A. I am not recommending any adjustment to the Company's proposal to recover these deferred costs over a three-year amortization period. In addition, since the KCC specifically permitted the Company to include carrying costs, I have accepted the inclusion of such carrying costs in the Company's claim. However, I recommend that the carrying costs be based on the 8.26% overall cost of capital that I am recommending in this case, rather than on the Company's proposed 9.60%.

Q. What is the basis for your recommendation?

A. The AAO stated that the carrying costs should be applied at the rate approved in the Company's last base rate case. However, that case was settled, and no overall cost of capital is identified in the Stipulation. The Company has therefore proposed that the overall cost of capital that it is recommending in this case be used to determine the appropriate carrying costs. Since I am recommending a different overall cost of capital, then it is necessary to adjust the customer conversion carrying costs accordingly. At Schedule ACC-23, I have recalculated the Company's claim using my overall recommended cost of capital of 8.26%. If the KCC finds that some other cost of capital should be adopted in this case, then that overall cost of capital should be used to determine carrying costs associated with the customer conversion adjustment.

G. **Outside Services Expense**

Q. Please describe your recommended adjustment to the Company's claim for outside services expense.

A. Outside services costs are impacted by the level of activity each year requiring outside services assistance, which can fluctuate greatly from year-to-year. A review of the Company's test year costs indicates that actual outside services costs were significantly higher in the test year than in any of the preceding four years, as shown below:

Calendar Year 2003	$657,490
Calendar Year 2004	$808,938
June 30, 2005	$797,455
Calendar Year 2005	$840,774
Test Year	$985,408

While KGO has stated that certain outside services costs have not been included in its filing, such as costs associated with its strategic repositioning activities and the sale of certain assets, the fact is that KGO was not operating in a "business as usual" mode during test year. Therefore, it is reasonable to examine the actual test year costs to determine if these costs represent a period of normal operating conditions and operating results. Given the fluctuation in outside services costs, and the significant strategic issues facing the Company during the test year, I believe that it is reasonable to recommend a normalization adjustment related to outside services costs.

Q. How did you quantify your adjustment?

A. I am recommending that a two-year average of outside services costs be used to set rates in this proceeding. I have quantified my adjustment at Schedule ACC-24. My adjustment results in pro forma outside services costs of $891,432.

H. Injuries and Damages Expense

Q. Are you recommending a similar normalization adjustment to the Company's claim for injuries and damages expense?

A. Yes, I am. Injuries and damages expense is another area where costs can fluctuate from year-to-year. Following are the actual costs incurred by KGO over the past several years:

Calendar Year 2003	$774,942
Calendar Year 2004	$605,195
June 30, 2005	$799,657
Calendar Year 2005	$1,007,848
Test Year	$983,032

Similar to my recommendation with regard to legal costs, I am recommending that the KCC utilize a two-year average for the Company's injuries and damages expenses. My adjustment is shown in Schedule ACC-25.

I. <u>Vehicle Loading Expense</u>

Q. Please explain your recommended adjustment to the Company's claim for vehicle loading expense.

A. This adjustment relates specifically to Company Adjustment No. 19, Kansas Electric Asset Sale Impact. In this adjustment, the Company included costs for incremental meter reading positions, associated benefits, and vehicle loadings that will be required once the sale of the Kansas electric properties is complete. This adjustment also reflected anticipated savings from the termination of a lease for certain office space.

In response to KCC-87, the Company indicated that vehicle loading costs of $32,000 included in this adjustment were overstated. Instead, KGO indicated that it should have included only $19,800 in vehicle loading expense. Accordingly, at Schedule ACC-26, I have made an adjustment to reduce the Company's claimed vehicle loading expense, consistent with this data request response.

J. Unspecified Reimbursements

Q. Has the Company included any perquisites given to executives in its revenue requirement claim?

A. Yes, it has. As shown in KCC-51, in this case KGO has included $13,748 of "lump sum perquisites." I understand that these lump sum payments are provided to certain executives to be used for business expenses not covered under general business reimbursement policies. These payments are, by definition, for unspecified purposes. Accordingly, the Company has not demonstrated that lump sum perquisites are necessary for the provision of safe and adequate utility service.

Q. What do you recommend?

A. I recommend that the lump sum perquisites be eliminated from KGO's cost of service. If these benefits are offered to executives, they should be paid for by shareholders, not regulated ratepayers. My adjustment is shown in Schedule ACC-27.

K. Legal Costs

Q. In addition to the Outside Services cost adjustment discussed above, are you recommending any other adjustments to the Company's claim with regard to legal costs?

A. Yes, I am. In a series of confidential discovery responses, specifically KCC-163, 164, 165, 166, and 181, the Company stated that it had included in its claim certain legal costs that should not have been included in its revenue requirement request. These costs generally relate to other regulatory proceedings, legal services provided prior to the test year, and costs that were incorrectly allocated, in whole or in part, to KGO. These legal costs total $23,348. At Schedule ACC-28, I have made an adjustment to eliminate these costs from the Company's claim. Since the data requests supporting this adjustment were deemed confidential by the Company, I have not shown the individual cost components on my supporting schedule, nor have I attached copies of these responses in Appendix C.

L. Depreciation Expense

Q Are you recommending any adjustment to the Company's depreciation expense claim?

A. Yes, I am recommending one adjustment. As discussed in the Rate Base section of this testimony, KGO included certain adjustments to depreciation expense and to the reserve for depreciation relating to deferred depreciation costs. This deferral was never authorized by the KCC. Therefore, recovery of these amounts in prospective rates would constitute retroactive ratemaking and should not be allowed. At Schedule ACC-29, I have made an adjustment to eliminate the amortization of these deferred costs from the Company's claim. My associated rate base adjustment was shown in Schedule ACC-9.

M. Interest Synchronization and Taxes

Q. Have you adjusted the pro forma interest expense for income tax purposes?

A. Yes, I have made this adjustment at Schedule ACC-30. It is consistent (synchronized) with my recommended rate base, capital structure, and cost of capital recommendations. I am recommending a lower rate base than the rate base included in the Company's filing. My recommendation results in a lower pro forma interest expense for the Company. This lower interest expense, which is an income tax deduction for state and federal tax purposes, will result in an increase to the Company's income tax liability under my recommendations. Therefore, my recommendations result in an interest synchronization adjustment that reflects a higher income tax burden for the Company, and a decrease to pro forma income at present rates.

Q. What income tax factors have you used to quantify your adjustments?

A. As shown on Schedule ACC-31, I have used a composite income tax factor of 39.78%, which includes a state income tax rate of 7.35% and a federal income tax rate of 35%. These are the state and federal income tax rates contained in the Company's filing.

VII. REVENUE REQUIREMENT SUMMARY

Q. What is the result of the recommendations contained in this testimony?

A. My adjustments result in a revenue requirement deficiency at present rates of $3,455,996, as summarized on Schedule ACC-1. This recommendation reflects revenue requirement adjustments of $3,784,222 to the Company's requested revenue requirement increase of $7,240,218.

Q. Have you quantified the revenue requirement impact of each of your recommendations?

A. Yes, at Schedule ACC-32, I have quantified the revenue requirement impact of the rate of return, rate base, revenue and expense recommendations contained in this testimony.

Q. Have you developed a pro forma income statement?

A. Yes, Schedule ACC-33 contains a pro forma income statement, showing utility operating income under several scenarios, including the Company's claimed operating income at present rates, my recommended operating income at present rates, and operating income under my proposed rate increase. My recommendations will result in an overall return on rate base of 8.26%.

VIII. DEMAND SIDE MANAGEMENT ("DSM") TARIFF RIDER

Q. Is the Company proposing any demand side management programs in its filing?

A. Yes, it is. The Company's proposed demand side management programs and cost recovery mechanism are described in the testimony of Mathew E. Daunis. KGO is proposing to provide certain space and water heating equipment rebates and to provide funding for low-income weatherization programs. KGO proposes to use primarily a Total Resources Cost ("TRC") approach to measure the effectiveness of its DSM program spending. In response to CURB-80, the Company stated that it expects to file a report on an annual basis with the KCC discussing its DSM programs and expenditures. In this response, KGO provided a sample report showing the types of information that KGO expects to include in its annual report to the KCC.

Q. Please describe the proposed programs in more detail.

A. As discussed in Exhibit MED-2, the Company is proposing a space and water heating equipment replacement rebate program. This program would provide rebates of up to $375 to customers for energy efficient furnaces and water heaters. KGO expects to offer rebates to 1,000 customers in 2007, increasing to 2,000 customers annually by 2009. The projected budget for the first year of the program is $265,250, increasing to $496,500 by 2009.

The second program being proposed by KGO is the low-income weatherization program. According to Exhibit MED-2, page 6, "[t]he Kansas Housing Resources Corporation (KHRC) operates the federal weatherization program in cooperation with nine local agencies (sub-grantees). With a total budget of $3.4 million in 2006 from the Department of Energy, Low-Income Heating Assistance Program and other sources, KHRC plans to weatherize over 1,200 homes with average spending of $2,780. Aquila proposes to provide funding to supplement the KHRC budget. Thus funding will allow the local agencies to serve additional households and to provide additional services within the households currently served."

KGO is proposing to serve 40 homes in 2007, increasing to 60 homes by 2009 and beyond. The expected cost of the program is $111,200 in 2007, increasing to an annual cost of $201,600 by 2011.

Q. How does KGO propose to recover the costs of these two programs?

A. KGO is proposing to implement a DSM tariff rider. KGO proposes that the initial rider be set to recover approximately $500,000 annually. By setting the surcharge somewhat higher than the budgeted costs for the first year, the Company hopes to avoid an increase in the second year, when the programs will have expanded to a larger customer base. According to Mr. Daunis, the initial surcharge will result in a cost of $0.44 per month or approximately $5.25 per year to the average residential customer.

Q. Is CURB supporting the Company's proposal in this case for a DSM tariff rider?

A. Yes, I have been informed that the governing board of CURB supports the Company's proposal for a DSM tariff rider. CURB believes that the tariff rider should be separately identified on customers' bills so that customers have a clear understanding of the nature and magnitude of the surcharge. In addition, the governing board of CURB supports the initial level of the DSM rider that is being requested by KGO. However, CURB believes that it is critical that the KCC, and other parties, carefully review the proposed programs for reasonableness.

Q. Do you believe that the specific programs being recommended by the Company are reasonable?

A. I am not opposed to the Company's space and water heating equipment rebate programs. However, I do have some concerns about the low-income weatherization program. While the Company contends that this program has a TRC of 1.25, other tests such as the Utility Cost Test ("UTC") and the Ratepayer Impact Test ("RIM") are much less favorable, as shown on page 8 of Exhibit MED-2. In addition, the initial cost of $2,780 per customer is very high and the projected cost per customer increases to $3,360 in five years. While I generally support governmental programs or programs sponsored by other entities that provide support to low-income customers, I believe that the level of support provided in this case may place an unreasonable burden on the Company's other customers. As shown in Exhibit MED-2, page 7, the cumulative annual program impact by 2011 is 8,235 Mcfs. Assuming a cost of $8.00 per Mcf, this would result in a total savings of approximately $66,000 in 2011. However, the Company projects that ratepayers will have spent approximately $832,800 over the initial five year period to achieve those savings. I am not sure that this is a reasonable burden to place on regulated ratepayers.

Q. What do you recommend?

A. Based on input from the governing board of CURB, I recommend that the KCC approve the Company's request to implement a DSM tariff rider, and establish an initial surcharge of $0.0071/therm. This is the rate that the Company estimates will be required in order to recover approximately $500,000 annually. I also recommend that the DSM tariff rider be clearly and separately identified on customers' bills.

I also recommend that the Company implement its space and water heating equipment replacement rebate program. However, at this time, I am not recommending that the Company participate in the low-income weatherization program, at least not to the extent outlined in Mr. Daunis's testimony. Instead, I recommend that the Company be directed to work with the KCC Staff, CURB, and other parties to review alternative programs that may provide a greater net benefit to the overall customer base. While CURB is not opposed to the total initial DSM funding level requested by KGO, there may be other more effective means of addressing low-income weatherization than proposed in the Company's filing. CURB would like to explore those possibilities.

Finally, I understand that the KCC has opened a generic docket to investigate energy efficiency programs, funding levels, recovery mechanisms, and evaluation methodologies (Docket No. 07-GIMX-247-GIV). The DSM tariff rider, and the associated DSM programs funded through the rider, may need to be revisited based on the results of that generic investigation.

Q. Does this conclude your testimony?

A. Yes, it does.

<u>VERIFICATION</u>

STATE OF CONNECTICUT)

COUNTY OF FAIRFIELD) ss:

Andrea C. Crane, being duly sworn upon her oath, deposes and states that she is a consultant for the Citizens' Utility Ratepayer Board, that she has read and is familiar with the foregoing testimony, and that the statements made herein are true to the best of her knowledge, information and belief.

Andrea C. Crane
Andrea C. Crane

Subscribed and sworn before me this 14th day of March, 2007.

Notary Public Marjorie McKeon

My Commission Expires: DECEMBER 31, 2008

APPENDIX A

List of Prior Testimonies

The Columbia Group, Inc., Testimonies of Andrea C. Crane

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Chesapeake Utilities Corporation	G	Delaware	06-287F	3/07	Gas Service Rates	Division of the Public Advocate
Delmarva Power and Light Company	G	Delaware	06-284	1/07	Revenue Requirements Cost of Capital	Division of the Public Advocate
El Paso Electric Company	E	New Mexico	06-00258 UT	11/06	Revenue Requirements	New Mexico Office of Attorney General
Aquila, Inc. / Mid-Kansas Electric Co.	E	Kansas	06-MKEE-524-ACQ	11/06	Proposed Acquisition	Citizens' Utility Ratepayer Board
Public Service Company of New Mexico	G	New Mexico	06-00210-UT	11/06	Revenue Requirements	New Mexico Office of Attorney General
Atlantic City Electric Company	E	New Jersey	EM06090638	11/06	Sale of B.L. England	Division of Rate Counsel
United Water Delaware, Inc.	W	Delaware	06-174	10/06	Revenue Requirements Cost of Capital	Division of the Public Advocate
Public Service Electric and Gas Company	G	New Jersey	GR05080686	10/06	Societal Benefits Charge	Division of Rate Counsel
Comcast (Avalon, Maple Shade, Gloucester)	C	New Jersey	CR06030136-139	10/06	Form 1205 and 1240 Cable Rates	Division of Rate Counsel
Kansas Gas Service	G	Kansas	06-KGSG-1209-RTS	9/06	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
New Jersey American Water Co. Elizabethtown Water Company Mount Holly Water Company	W	New Jersey	WR06030257	9/06	Regulatory Policy Taxes Cash Working Capital	Division of Rate Counsel
Tidewater Utilities, Inc.	W	Delaware	06-145	9/06	Revenue Requirements Cost of Capital	Division of the Public Advocate
Artesian Water Company	W	Delaware	06-158	9/06	Revenue Requirements Cost of Capital	Division of the Public Advocate
Kansas City Power & Light Company	E	Kansas	06-KCPE-828-RTS	8/06	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Midwest Energy, Inc.	G	Kansas	06-MDWG-1027-RTS	7/06	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Cablevision Systems Corporation	C	New Jersey	CR05110924, et al.	5/06	Cable Rates - Forms 1205 and 1240	Division of the Ratepayer Advocate
Montague Sewer Company	WW	New Jersey	WR05121056	5/06	Revenue Requirements	Division of the Ratepayer Advocate
Comcast of South Jersey	C	New Jersey	CR05119035, et al.	5/06	Cable Rates - Form 1240	Division of the Ratepayer Advocate
Comcast of New Jersey	C	New Jersey	CR05090826-827	4/06	Cable Rates - Form 1240	Division of the Ratepayer Advocate
Parkway Water Company	W	New Jersey	WR05070634	3/06	Revenue Requirements Cost of Capital	Division of the Ratepayer Advocate
Aqua Pennsylvania, Inc.	W	Pennsylvania	R-00051030	2/06	Revenue Requirements	Office of Consumer Advocate
Delmarva Power and Light Company	G	Delaware	05-312F	2/06	Gas Cost Rates	Division of the Public Advocate
Delmarva Power and Light Company	E	Delaware	05-304	12/05	Revenue Requirements Cost of Capital	Division of the Public Advocate

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Artesian Water Company	W	Delaware	04-42	10/05	Revenue Requirements Cost of Capital (Remand)	Division of the Public Advocate
Utility Systems, Inc.	WW	Delaware	335-05	9/05	Regulatory Policy	Division of the Ratepayer Advocate
Westar Energy, Inc.	E	Kansas	05-WSEE-981-RTS	9/05	Revenue Requirements	Citizens' Utility Ratepayer Board
Empire Electric District Company	E	Kansas	05-EPDE-980-RTS	8/05	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Comcast Cable	C	New Jersey	CR05030186	8/05	Form 1205	Division of the Ratepayer Advocate
Pawtucket Water Supply Board	W	Rhode Island	3674	7/05	Revenue Requirements	Division of Public Utilities and Carriers
Delmarva Power and Light Company	E	Delaware	04-391	7/05	Standard Offer Service	Division of the Public Advocate
Patriot Media & Communications CNJ, LLC	C	New Jersey	CR04111453-455	6/05	Cable Rates	Division of the Ratepayer Advocate
Cablevision	C	New Jersey	CR04111379, et al.	6/05	Cable Rates	Division of the Ratepayer Advocate
Comcast of Mercer County, LLC	C	New Jersey	CR04111458	6/05	Cable Rates	Division of the Ratepayer Advocate
Comcast of South Jersey, LLC, et al.	C	New Jersey	CR04101356, et al.	5/05	Cable Rates	Division of the Ratepayer Advocate
Comcast of Central New Jersey LLC, et al.	C	New Jersey	CR04101077, et al.	4/05	Cable Rates	Division of the Ratepayer Advocate
Kent County Water Authority	W	Rhode Island	3660	4/05	Revenue Requirements	Division of Public Utilities and Carriers
Aquila, Inc.	G	Kansas	05-AQLG-367-RTS	3/05	Revenue Requirements Cost of Capital Tariff Issues	Citizens' Utility Ratepayer Board
Chesapeake Utilities Corporation	G	Delaware	04-334F	3/05	Gas Service Rates	Division of the Public Advocate
Delmarva Power and Light Company	G	Delaware	04-301F	3/05	Gas Cost Rates	Division of the Public Advocate
Delaware Electric Cooperative, Inc.	E	Delaware	04-288	12/04	Revenue Requirements Cost of Capital	Division of the Public Advocate
Public Service Company of New Mexico	E	New Mexico	04-00311-UT	11/04	Renewable Energy Plans	Office of the New Mexico Attorney General
Woonsocket Water Division	W	Rhode Island	3626	10/04	Revenue Requirements	Division of Public Utilities and Carriers
Aquila, Inc.	E	Kansas	04-AQLE-1065-RTS	10/04	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
United Water Delaware, Inc.	W	Delaware	04-121	8/04	Conservation Rates (Affidavit)	Division of the Public Advocate
Atlantic City Electric Company	E	New Jersey	ER03020110 PUC 06061-2003S	8/04	Deferred Balance Phase II	Division of the Ratepayer Advocate

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Kentucky American Water Company	W	Kentucky	2004-00103	8/04	Revenue Requirements	Office of Rate Intervention of the Attorney General
Shorelands Water Company	W	New Jersey	WR04040295	8/04	Revenue Requirements Cost of Capital	Division of the Ratepayer Advocate
Artesian Water Company	W	Delaware	04-42	8/04	Revenue Requirements Cost of Capital	Division of the Public Advocate
Long Neck Water Company	W	Delaware	04-31	7/04	Cost of Equity	Division of the Public Advocate
Tidewater Utilities, Inc.	W	Delaware	04-152	7/04	Cost of Capital	Division of the Public Advocate
Cablevision	C	New Jersey	CR03100850, et al.	6/04	Cable Rates	Division of the Ratepayer Advocate
Montague Water and Sewer Companies	W/WW	New Jersey	WR03121034 (W) WR03121035 (S)	5/04	Revenue Requirements	Division of the Ratepayer Advocate
Comcast of South Jersey, Inc.	C	New Jersey	CR03100876,77,79,80	5/04	Form 1240 Cable Rates	Division of the Ratepayer Advocate
Comcast of Central New Jersey, et al.	C	New Jersey	CR03100749-750 CR03100759-762	4/04	Cable Rates	Division of the Ratepayer Advocate
Time Warner	C	New Jersey	CR03100763-764	4/04	Cable Rates	Division of the Ratepayer Advocate
Interstate Navigation Company	N	Rhode Island	3573	3/04	Revenue Requirements	Division of Public Utilities and Carriers
Aqua Pennsylvania, Inc.	W	Pennsylvania	R-00038805	2/04	Revenue Requirements	Pennsylvania Office of Consumer Advocate
Comcast of Jersey City, et al.	C	New Jersey	CR03080598-601	2/04	Cable Rates	Division of the Ratepayer Advocate
Delmarva Power and Light Company	G	Delaware	03-378F	2/04	Fuel Clause	Division of the Public Advocate
Atmos Energy Corp.	G	Kansas	03-ATMG-1036-RTS	11/03	Revenue Requirements	Citizens' Utility Ratepayer Board
Aquila, Inc. (UCU)	G	Kansas	02-UTCG-701-GIG	10/03	Using utility assets as collateral	Citizens' Utility Ratepayer Board
CenturyTel of Northwest Arkansas, LLC	T	Arkansas	03-041-U	10/03	Affiliated Interests	The Arkansas Public Service Commission General Staff
Borough of Butler Electric Utility	E	New Jersey	CR03010049/63	9/03	Revenue Requirements	Division of the Ratepayer Advocate
Comcast Cablevision of Avalon Comcast Cable Communications	C	New Jersey	CR03020131-132	9/03	Cable Rates	Division of the Ratepayer Advocate
Delmarva Power and Light Company d/b/a Conectiv Power Delivery	E	Delaware	03-127	8/03	Revenue Requirements	Division of the Public Advocate
Kansas Gas Service	G	Kansas	03-KGSG-602-RTS	7/03	Revenue Requirements	Citizens' Utility Ratepayer Board
Washington Gas Light Company	G	Maryland	8959	6/03	Cost of Capital Incentive Rate Plan	U.S. DOD/FEA

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Pawtucket Water Supply Board	W	Rhode Island	3497	6/03	Revenue Requirements	Division of Public Utilities and Carriers
Atlantic City Electric Company	E	New Jersey	EO03020091	5/03	Stranded Costs	Division of the Ratepayer Advocate
Public Service Company of New Mexico	G	New Mexico	03-000-17 UT	5/03	Cost of Capital Cost Allocations	Office of the New Mexico Attorney General
Comcast - Hopewell, et al.	C	New Jersey	CR02110818 CR02110823-825	5/03	Cable Rates	Division of the Ratepayer Advocate
Cablevision Systems Corporation	C	New Jersey	CR02110838, 43-50	4/03	Cable Rates	Division of the Ratepayer Advocate
Comcast-Garden State / Northwest	C	New Jersey	CR02100715 CR02100719	4/03	Cable Rates	Division of the Ratepayer Advocate
Midwest Energy, Inc. and Westar Energy, Inc.	E	Kansas	03-MDWE-421-ACQ	4/03	Acquisition	Citizens' Utility Ratepayer Board
Time Warner Cable	C	New Jersey	CR02100722 CR02100723	4/03	Cable Rates	Division of the Ratepayer Advocate
Westar Energy, Inc.	E	Kansas	01-WSRE-949-GIE	3/03	Restructuring Plan	Citizens' Utility Ratepayer Board
Public Service Electric and Gas Company	E	New Jersey	ER02080604 PUC 7983-02	1/03	Deferred Balance	Division of the Ratepayer Advocate
Atlantic City Electric Company d/b/a Conectiv Power Delivery	E	New Jersey	ER02080510 PUC 6917-02S	1/03	Deferred Balance	Division of the Ratepayer Advocate
Wallkill Sewer Company	WW	New Jersey	WR02030193 WR02030194	12/02	Revenue Requirements Purchased Sewage Treatment Adj. (PSTAC)	Division of the Ratepayer Advocate
Midwest Energy, Inc.	E	Kansas	03-MDWE-001-RTS	12/02	Revenue Requirements	Citizens' Utility Ratepayer Board
Comcast-LBI Crestwood	C	New Jersey	CR02050272 CR02050270	11/02	Cable Rates	Division of the Ratepayer Advocate
Reliant Energy Arkla	G	Oklahoma	PUD200200166	10/02	Affiliated Interest Transactions	Oklahoma Corporation Commission, Public Utility Division Staff
Midwest Energy, Inc.	G	Kansas	02-MDWG-922-RTS	10/02	Gas Rates	Citizens' Utility Ratepayer Board
Comcast Cablevision of Avalon	C	New Jersey	CR02030134 CR02030137	7/02	Cable Rates	Division of the Ratepayer Advocate
RCN Telecom Services, Inc., and Home Link Communications	C	New Jersey	CR02010044, CR02010047	7/02	Cable Rates	Division of the Ratepayer Advocate
Washington Gas Light Company	G	Maryland	8920	7/02	Rate of Return Rate Design (Rebuttal)	General Services Administration (GSA)
Chesapeake Utilities Corporation	G	Delaware	01-307, Phase II	7/02	Rate Design Tariff Issues	Division of the Public Advocate
Washington Gas Light Company	G	Maryland	8920	6/02	Rate of Return Rate Design	General Services Administration (GSA)
Tidewater Utilities, Inc.	W	Delaware	02-28	6/02	Revenue Requirements	Division of the Public Advocate

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Western Resources, Inc.	E	Kansas	01-WSRE-949-GIE	5/02	Financial Plan	Citizens' Utility Ratepayer Board
Empire District Electric Company	E	Kansas	02-EPDE-488-RTS	5/02	Revenue Requirements	Citizens' Utility Ratepayer Board
Southwestern Public Service Company	E	New Mexico	3709	4/02	Fuel Costs	Office of the New Mexico Attorney General
Cablevision Systems	C	New Jersey	CR01110706, et al	4/02	Cable Rates	Division of the Ratepayer Advocate
Potomac Electric Power Company	E	District of Columbia	945, Phase II	4/02	Divestiture Procedures	General Services Administration (GSA)
Vermont Yankee Nuclear Power Corp.	E	Vermont	6545	3/02	Sale of VY to Entergy Corp. (Supplemental)	Department of Public Service
Delmarva Power and Light Company	G	Delaware	01-348F	1/02	Gas Cost Adjustment	Division of the Public Advocate
Vermont Yankee Nuclear Power Corp.	E	Vermont	6545	1/02	Sale of VY to Entergy Corp.	Department of Public Service
Pawtucket Water Supply Company	W	Rhode Island	3378	12/01	Revenue Requirements	Division of Public Utilities and Carriers
Chesapeake Utilities Corporation	G	Delaware	01-307, Phase I	12/01	Revenue Requirements	Division of the Public Advocate
Potomac Electric Power Company	E	Maryland	8796	12/01	Divestiture Procedures	General Services Administration (GSA)
Kansas Electric Power Cooperative	E	Kansas	01-KEPE-1106-RTS	11/01	Depreciation Methodology (Cross Answering)	Citizens' Utility Ratepayer Board
Wellsboro Electric Company	E	Pennsylvania	R-00016356	11/01	Revenue Requirements	Office of Consumer Advocate
Kent County Water Authority	W	Rhode Island	3311	10/01	Revenue Requirements (Surrebuttal)	Division of Public Utilities and Carriers
Pepco and New RC, Inc.	E	District of Columbia	1002	10/01	Merger Issues and Performance Standards	General Services Administration (GSA)
Potomac Electric Power Co. & Delmarva Power	E	Delaware	01-194	10/01	Merger Issues and Performance Standards	Division of the Public Advocate
Yankee Gas Company	G	Connecticut	01-05-19PH01	9/01	Affiliated Transactions	Office of Consumer Counsel
Hope Gas, Inc., d/b/a Dominion Hope	G	West Virginia	01-0330-G-42T 01-0331-G-30C 01-1842-GT-T 01-0685-G-PC	9/01	Revenue Requirements (Rebuttal)	The Consumer Advocate Division of the PSC
Pennsylvania-American Water Company	W	Pennsylvania	R-00016339	9/01	Revenue Requirements (Surrebuttal)	Office of Consumer Advocate
Potomac Electric Power Co. & Delmarva Power	E	Maryland	8890	9/01	Merger Issues and Performance Standards	General Services Administration (GSA)
Comcast Cablevision of Long Beach Island, et al	C	New Jersey	CR01030149-50 CR01050285	9/01	Cable Rates	Division of the Ratepayer Advocate
Kent County Water Authority	W	Rhode Island	3311	8/01	Revenue Requirements	Division of Public Utilities and Carriers

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Pennsylvania-American Water Company	W	Pennsylvania	R-00016339	8/01	Revenue Requirements	Office of Consumer Advocate
Roxiticus Water Company	W	New Jersey	WR01030194	8/01	Revenue Requirements Cost of Capital Rate Design	Division of the Ratepayer Advocate
Hope Gas, Inc., d/b/a Dominion Hope	G	West Virginia	01-0330-G-42T 01-0331-G-30C 01-1842-GT-T 01-0685-G-PC	8/01	Revenue Requirements	Consumer Advocate Division of the PSC
Western Resources, Inc.	E	Kansas	01-WSRE-949-GIE	6/01	Restructuring Financial Integrity (Rebuttal)	Citizens' Utility Ratepayer Board
Western Resources, Inc.	E	Kansas	01-WSRE-949-GIE	6/01	Restructuring Financial Integrity	Citizens' Utility Ratepayer Board
Cablevision of Allamuchy, et al	C	New Jersey	CR00100824, etc.	4/01	Cable Rates	Division of the Ratepayer Advocate
Public Service Company of New Mexico	E	New Mexico	3137, Holding Co.	4/01	Holding Company	Office of the Attorney General
Keauhou Community Services, Inc.	W	Hawaii	00-0094	4/01	Rate Design	Division of Consumer Advocacy
Western Resources, Inc.	E	Kansas	01-WSRE-436-RTS	4/01	Revenue Requirements Affiliated Interests (Motion for Suppl. Changes)	Citizens' Utility Ratepayer Board
Western Resources, Inc.	E	Kansas	01-WSRE-436-RTS	4/01	Revenue Requirements Affiliated Interests	Citizens' Utility Ratepayer Board
Public Service Company of New Mexico	E	New Mexico	3137, Part III	4/01	Standard Offer Service (Additional Direct)	Office of the Attorney General
Chem-Nuclear Systems, LLC	SW	South Carolina	2000-366-A	3/01	Allowable Costs	Department of Consumer Affairs
Southern Connecticut Gas Company	G	Connecticut	00-12-08	3/01	Affiliated Interest Transactions	Office of Consumer Counsel
Atlantic City Sewerage Corporation	WW	New Jersey	WR00080575	3/01	Revenue Requirements Cost of Capital Rate Design	Division of the Ratepayer Advocate
Delmarva Power and Light Company d/b/a Conectiv Power Delivery	G	Delaware	00-314	3/01	Margin Sharing	Division of the Public Advocate
Senate Bill 190 Re: Performance Based Ratemaking	G	Kansas	Senate Bill 190	2/01	Performance-Based Ratemaking Mechanisms	Citizens' Utility Ratepayer Board
Delmarva Power and Light Company	G	Delaware	00-463-F	2/01	Gas Cost Rates	Division of the Public Advocate
Waitsfield Fayston Telephone Company	T	Vermont	6417	12/00	Revenue Requirements	Department of Public Service
Delaware Electric Cooperative	E	Delaware	00-365	11/00	Code of Conduct Cost Allocation Manual	Division of the Public Advocate
Commission Inquiry into Performance-Based Ratemaking	G	Kansas	00-GIMG-425-GIG	10/00	Performance-Based Ratemaking Mechanisms	Citizens' Utility Ratepayer Board
Pawtucket Water Supply Board	W	Rhode Island	3164 Separation Plan	10/00	Revenue Requirements	Division of Public Utilities and Carriers

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Comcast Cablevision of Philadelphia, L.P.	C	Pennsylvania	3756	10/00	Late Payment Fees (Affidavit)	Kaufman, Lankelis, et al.
Public Service Company of New Mexico	E	New Mexico	3137, Part III	9/00	Standard Offer Service	Office of the Attorney General
Laie Water Company	W	Hawaii	00-0017 Separation Plan	8/00	Rate Design	Division of Consumer Advocacy
El Paso Electric Company	E	New Mexico	3170, Part II, Ph. 1	7/00	Electric Restructuring	Office of the Attorney General
Public Service Company of New Mexico	E	New Mexico	3137 - Part II Separation Plan	7/00	Electric Restructuring	Office of the Attorney General
PG Energy	G	Pennsylvania	R-00005119	6/00	Revenue Requirements	Office of Consumer Advocate
Consolidated Edison, Inc. and Northeast Utilities	E/G	Connecticut	00-01-11	4/00	Merger Issues (Additional Supplemental)	Office of Consumer Counsel
Sussex Shores Water Company	W	Delaware	99-576	4/00	Revenue Requirements	Division of the Public Advocate
Utilicorp United, Inc.	G	Kansas	00-UTCG-336-RTS	4/00	Revenue Requirements	Citizens' Utility Ratepayer Board
TCI Cablevision	C	Missouri	9972-9146	4/00	Late Fees (Affidavit)	Honora Eppert, et al
Oklahoma Natural Gas Company	G	Oklahoma	PUD 990000166 PUD 980000683 PUD 990000570	3/00	Pro Forma Revenue Affiliated Transactions (Rebuttal)	Oklahoma Corporation Commission, Public Utility Division Staff
Tidewater Utilities, Inc. Public Water Supply Co.	W	Delaware	99-466	3/00	Revenue Requirements	Division of the Public Advocate
Delmarva Power and Light Company	G/E	Delaware	99-582	3/00	Cost Accounting Manual Code of Conduct	Division of the Public Advocate
Philadelphia Suburban Water Company	W	Pennsylvania	R-00994868 R-00994877 R-00994878 R-00994879	3/00	Revenue Requirements (Surrebuttal)	Office of Consumer Advocate
Philadelphia Suburban Water Company	W	Pennsylvania	R-00994868 R-00994877 R-00994878 R-00994879	2/00	Revenue Requirements	Office of Consumer Advocate
Consolidated Edison, Inc. and Northeast Utilities	E/G	Connecticut	00-01-11	2/00	Merger Issues	Office of Consumer Counsel
Oklahoma Natural Gas Company	G	Oklahoma	PUD 990000166 PUD 980000683 PUD 990000570	1/00	Pro Forma Revenue Affiliated Transactions	Oklahoma Corporation Commission, Public Utility Division Staff
Connecticut Natural Gas Company	G	Connecticut	99-09-03	1/00	Affiliated Transactions	Office of Consumer Counsel
Time Warner Entertainment Company, L.P.	C	Indiana	48D06-9803-CP-423	1999	Late Fees (Affidavit)	Kelly J. Whiteman, et al
TCI Communications, Inc., et al	C	Indiana	55D01-9709-CP-00415	1999	Late Fees (Affidavit)	Franklin E. Littell, et al
Southwestern Public Service Company	E	New Mexico	3116	12/99	Merger Approval	Office of the Attorney General

Company	Utility	State	Docket	Date	Topic	On Behalf Of
New England Electric System Eastern Utility Associates	E	Rhode Island	2930	11/99	Merger Policy	Department of Attorney General
Delaware Electric Cooperative	E	Delaware	99-457	11/99	Electric Restructuring	Division of the Public Advocate
Jones Intercable, Inc.	C	Maryland	CAL98-00283	10/99	Cable Rates (Affidavit)	Cynthia Maisonette and Ola Renee Chatman, et al
Texas-New Mexico Power Company	E	New Mexico	3103	10/99	Acquisition Issues	Office of Attorney General
Southern Connecticut Gas Company	G	Connecticut	99-04-18	9/99	Affiliated Interest	Office of Consumer Counsel
TCI Cable Company	C	New Jersey	CR99020079 et al	9/99	Cable Rates Forms 1240/1205	Division of the Ratepayer Advocate
All Regulated Companies	E/G/W	Delaware	Reg. No. 4	8/99	Filing Requirements (Position Statement)	Division of the Public Advocate
Mile High Cable Partners	C	Colorado	95-CV-5195	7/99	Cable Rates (Affidavit)	Brett Marshall, an individual, et al
Electric Restructuring Comments	E	Delaware	Reg. 49	7/99	Regulatory Policy (Supplemental)	Division of the Public Advocate
Long Neck Water Company	W	Delaware	99-31	6/99	Revenue Requirements	Division of the Public Advocate
Delmarva Power and Light Company	E	Delaware	99-163	6/99	Electric Restructuring	Division of the Public Advocate
Potomac Electric Power Company	E	District of Columbia	945	6/99	Divestiture of Generation Assets	U.S. GSA - Public Utilities
Comcast	C	Indiana	49C01-9802-CP-000386	6/99	Late Fees (Affidavit)	Ken Hecht, et al
Petitions of BA-NJ and NJPA re: Payphone Ops	T	New Jersey	TO97100792 PUCOT 11269-97N	6/99	Economic Subsidy Issues (Surrebuttal)	Division of the Ratepayer Advocate
Montague Water and Sewer Companies	W/WW	New Jersey	WR98101161 WR98101162 PUCRS 11514-98N	5/99	Revenue Requirements Rate Design (Supplemental)	Division of the Ratepayer Advocate
Cablevision of Bergen, Bayonne, Newark	C	New Jersey	CR98111197-199 CR98111190	5/99	Cable Rates Forms 1240/1205	Division of the Ratepayer Advocate
Cablevision of Bergen, Hudson, Monmouth	C	New Jersey	CR97090624-626 CTV 1697-98N	5/99	Cable Rates - Form 1235 (Rebuttal)	Division of the Ratepayer Advocate
Kent County Water Authority	W	Rhode Island	2860	4/99	Revenue Requirements	Division of Public Utilities & Carriers
Montague Water and Sewer Companies	W/WW	New Jersey	WR98101161 WR98101162	4/99	Revenue Requirements Rate Design	Division of the Ratepayer Advocate
PEPCO	E	District of Columbia	945	4/99	Divestiture of Assets	U.S. GSA - Public Utilities
Western Resources, Inc. and Kansas City Power & Light	E	Kansas	97-WSRE-676-MER	4/99	Merger Approval (Surrebuttal)	Citizens' Utility Ratepayer Board
Delmarva Power and Light Company	E	Delaware	98-479F	3/99	Fuel Costs	Division of the Public Advocate

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Lenfest Atlantic d/b/a Suburban Cable	C	New Jersey	CR97070479 et al	3/99	Cable Rates	Division of the Ratepayer Advocate
Electric Restructuring Comments	E	District of Columbia	945	3/99	Regulatory Policy	U.S. GSA - Public Utilities
Petitions of BA-NJ and NJPA re: Payphone Ops	T	New Jersey	TO97100792 PUCOT 11269-97N	3/99	Tariff Revision Payphone Subsidies FCC Services Test (Rebuttal)	Division of the Ratepayer Advocate
Western Resources, Inc. and Kansas City Power & Light	E	Kansas	97-WSRE-676-MER	3/99	Merger Approval (Answering)	Citizens' Utility Ratepayer Board
Western Resources, Inc. and Kansas City Power & Light	E	Kansas	97-WSRE-676-MER	2/99	Merger Approval	Citizens' Utility Ratepayer Board
Adelphia Cable Communications	C	Vermont	6117-6119	1/99	Late Fees (Additional Direct Supplemental)	Department of Public Service
Adelphia Cable Communications	C	Vermont	6117-6119	12/98	Cable Rates (Forms 1240, 1205, 1235) and Late Fees (Direct Supplemental)	Department of Public Service
Adelphia Cable Communications	C	Vermont	6117-6119	12/98	Cable Rates (Forms 1240, 1205, 1235) and Late Fees	Department of Public Service
Orange and Rockland/ Consolidated Edison	E	New Jersey	EM98070433	11/98	Merger Approval	Division of the Ratepayer Advocate
Cablevision	C	New Jersey	CR97090624 CR97090625 CR97090626	11/98	Cable Rates - Form 1235	Division of the Ratepayer Advocate
Petitions of BA-NJ and NJPA re: Payphone Ops.	T	New Jersey	TO97100792 PUCOT 11269-97N	10/98	Payphone Subsidies FCC New Services Test	Division of the Ratepayer Advocate
United Water Delaware	W	Delaware	98-98	8/98	Revenue Requirements	Division of the Public Advocate
Cablevision	C	New Jersey	CR97100719, 726 730, 732	8/98	Cable Rates (Oral Testimony)	Division of the Ratepayer Advocate
Potomac Electric Power Company	E	Maryland	Case No. 8791	8/98	Revenue Requirements Rate Design	U.S. GSA - Public Utilities
Investigation of BA-NJ IntraLATA Calling Plans	T	New Jersey	TO97100808 PUCOT 11326-97N	8/98	Anti-Competitive Practices (Rebuttal)	Division of the Ratepayer Advocate
Investigation of BA-NJ IntraLATA Calling Plans	T	New Jersey	TO97100808 PUCOT 11326-97N	7/98	Anti-Competitive Practices	Division of the Ratepayer Advocate
TCI Cable Company/ Cablevision	C	New Jersey	CTV 03264-03268 and CTV 05061	7/98	Cable Rates	Division of the Ratepayer Advocate
Mount Holly Water Company	W	New Jersey	WR98020058 PUC 03131-98N	7/98	Revenue Requirements	Division of the Ratepayer Advocate
Pawtucket Water Supply Board	W	Rhode Island	2674	5/98	Revenue Requirements (Surrebuttal)	Division of Public Utilities & Carriers
Pawtucket Water Supply Board	W	Rhode Island	2674	4/98	Revenue Requirements	Division of Public Utilities and Carriers

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Energy Master Plan Phase II Proceeding - Restructuring	E	New Jersey	EX94120585U, EO97070457,60,63,66	4/98	Electric Restructuring Issues (Supplemental Surrebuttal)	Division of the Ratepayer Advocate
Energy Master Plan Phase I Proceeding - Restructuring	E	New Jersey	EX94120585U, EO97070457,60,63,66	3/98	Electric Restructuring Issues	Division of the Ratepayer Advocate
Shorelands Water Company	W	New Jersey	WR97110835 PUC 11324-97	2/98	Revenue Requirements	Division of the Ratepayer Advocate
TCI Communications, Inc.	C	New Jersey	CR97030141 and others	11/97	Cable Rates (Oral Testimony)	Division of the Ratepayer Advocate
Citizens Telephone Co. of Kecksburg	T	Pennsylvania	R-00971229	11/97	Alternative Regulation Network Modernization	Office of Consumer Advocate
Consumers Pennsylvania Water Co. - Shenango Valley Division	W	Pennsylvania	R-00973972	10/97	Revenue Requirements (Surrebuttal)	Office of Consumer Advocate
Universal Service Funding	T	New Jersey	TX95120631	10/97	Schools and Libraries Funding (Rebuttal)	Division of the Ratepayer Advocate
Universal Service Funding	T	New Jersey	TX95120631	9/97	Low Income Fund High Cost Fund	Division of the Ratepayer Advocate
Consumers Pennsylvania Water Co. - Shenango Valley Division	W	Pennsylvania	R-00973972	9/97	Revenue Requirements	Office of Consumer Advocate
Delmarva Power and Light Company	G/E	Delaware	97-65	9/97	Cost Accounting Manual Code of Conduct	Office of the Public Advocate
Western Resources, Oneok, and WAI	G	Kansas	WSRG-486-MER	9/97	Transfer of Gas Assets	Citizens' Utility Ratepayer Board
Universal Service Funding	T	New Jersey	TX95120631	9/97	Schools and Libraries Funding (Rebuttal)	Division of the Ratepayer Advocate
Universal Service Funding	T	New Jersey	TX95120631	8/97	Schools and Libraries Funding	Division of the Ratepayer Advocate
Kent County Water Authority	W	Rhode Island	2555	8/97	Revenue Requirements (Surrebuttal)	Division of Public Utilities and Carriers
Ironton Telephone Company	T	Pennsylvania	R-00971182	8/97	Alternative Regulation Network Modernization (Surrebuttal)	Office of Consumer Advocate
Ironton Telephone Company	T	Pennsylvania	R-00971182	7/97	Alternative Regulation Network Modernization	Office of Consumer Advocate
Comcast Cablevision	C	New Jersey	Various	7/97	Cable Rates (Oral Testimony)	Division of the Ratepayer Advocate
Maxim Sewerage Corporation	WW	New Jersey	WR97010052 PUCRA 3154-97N	7/97	Revenue Requirements	Division of the Ratepayer Advocate
Kent County Water Authority	W	Rhode Island	2555	6/97	Revenue Requirements	Division of Public Utilities and Carriers
Consumers Pennsylvania Water Co. - Roaring Creek	W	Pennsylvania	R-00973869	6/97	Revenue Requirements (Surrebuttal)	Office of Consumer Advocate
Consumers Pennsylvania Water Co. - Roaring Creek	W	Pennsylvania	R-00973869	5/97	Revenue Requirements	Office of Consumer Advocate

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Delmarva Power and Light Company	E	Delaware	97-58	5/97	Merger Policy	Office of the Public Advocate
Middlesex Water Company	W	New Jersey	WR96110818 PUCRL 11663-96N	4/97	Revenue Requirements	Division of the Ratepayer Advocate
Maxim Sewerage Corporation	WW	New Jersey	WR96080628 PUCRA 09374-96N	3/97	Purchased Sewerage Adjustment	Division of the Ratepayer Advocate
Interstate Navigation Company	N	Rhode Island	2484	3/97	Revenue Requirements Cost of Capital (Surrebuttal)	Division of Public Utilities & Carriers
Interstate Navigation Company	N	Rhode Island	2484	2/97	Revenue Requirements Cost of Capital	Division of Public Utilities & Carriers
Electric Restructuring Comments	E	District of Columbia	945	1/97	Regulatory Policy	U.S. GSA - Public Utilities
United Water Delaware	W	Delaware	96-194	1/97	Revenue Requirements	Office of the Public Advocate
PEPCO/ BGE/ Merger Application	E/G	District of Columbia	951	10/96	Regulatory Policy Cost of Capital (Rebuttal)	GSA
Western Resources, Inc.	E	Kansas	193,306-U 193,307-U	10/96	Revenue Requirements Cost of Capital (Supplemental)	Citizens' Utility Ratepayer Board
PEPCO and BGE Merger Application	E/G	District of Columbia	951	9/96	Regulatory Policy, Cost of Capital	U.S. GSA - Public Utilities
Utilicorp United, Inc.	G	Kansas	193,787-U	8/96	Revenue Requirements	Citizens' Utility Ratepayer Board
TKR Cable Company of Gloucester	C	New Jersey	CTV07030-95N	7/96	Cable Rates (Oral Testimony)	Division of the Ratepayer Advocate
TKR Cable Company of Warwick	C	New Jersey	CTV057537-95N	7/96	Cable Rates (Oral Testimony)	Division of the Ratepayer Advocate
Delmarva Power and Light Company	E	Delaware	95-196F	5/96	Fuel Cost Recovery	Office of the Public Advocate
Western Resources, Inc.	E	Kansas	193,306-U 193,307-U	5/96	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Princeville Utilities Company, Inc.	W/WW	Hawaii	95-0172 95-0168	1/96	Revenue Requirements Rate Design	Princeville at Hanalei Community Association
Western Resources, Inc.	G	Kansas	193,305-U	1/96	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Environmental Disposal Corporation	WW	New Jersey	WR94070319 (Remand Hearing)	11/95	Revenue Requirements Rate Design (Supplemental)	Division of the Ratepayer Advocate
Environmental Disposal Corporation	WW	New Jersey	WR94070319 (Remand Hearing)	11/95	Revenue Requirements	Division of the Ratepayer Advocate
Lanai Water Company	W	Hawaii	94-0366	10/95	Revenue Requirements Rate Design	Division of Consumer Advocacy
Cablevision of New Jersey, Inc.	C	New Jersey	CTV01382-95N	8/95	Basic Service Rates (Oral Testimony)	Division of the Ratepayer Advocate

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Cablevision of New Jersey, Inc.	C	New Jersey	CTV01381-95N	8/95	Basic Service Rates (Oral Testimony)	Division of the Ratepayer Advocate
Chesapeake Utilities Corporation	G	Delaware	95-73	7/95	Revenue Requirements	Office of the Public Advocate
East Honolulu Community Services, Inc.	WW	Hawaii	7718	6/95	Revenue Requirements	Division of Consumer Advocacy
Wilmington Suburban Water Corporation	W	Delaware	94-149	3/95	Revenue Requirements	Office of the Public Advocate
Environmental Disposal Corporation	WW	New Jersey	WR94070319	1/95	Revenue Requirements (Supplemental)	Division of the Ratepayer Advocate
Roaring Creek Water Company	W	Pennsylvania	R-00943177	1/95	Revenue Requirements (Surrebuttal)	Office of Consumer Advocate
Roaring Creek Water Company	W	Pennsylvania	R-00943177	12/94	Revenue Requirements	Office of Consumer Advocate
Environmental Disposal Corporation	WW	New Jersey	WR94070319	12/94	Revenue Requirements	Division of the Ratepayer Advocate
Delmarva Power and Light Company	E	Delaware	94-84	11/94	Revenue Requirements	Office of the Public Advocate
Delmarva Power and Light Company	G	Delaware	94-22	8/94	Revenue Requirements	Office of the Public Advocate
Empire District Electric Company	E	Kansas	190,360-U	8/94	Revenue Requirements	Citizens' Utility Ratepayer Board
Morris County Municipal Utility Authority	SW	New Jersey	MM10930027 ESW 1426-94	6/94	Revenue Requirements	Rate Counsel
US West Communications	T	Arizona	E-1051-93-183	5/94	Revenue Requirements (Surrebuttal)	Residential Utility Consumer Office
Pawtucket Water Supply Board	W	Rhode Island	2158	5/94	Revenue Requirements (Surrebuttal)	Division of Public Utilities & Carriers
US West Communications	T	Arizona	E-1051-93-183	3/94	Revenue Requirements	Residential Utility Consumer Office
Pawtucket Water Supply Board	W	Rhode Island	2158	3/94	Revenue Requirements	Division of Public Utilities & Carriers
Pollution Control Financing Authority of Camden County	SW	New Jersey	SR91111718J	2/94	Revenue Requirements (Supplemental)	Rate Counsel
Roaring Creek Water Company	W	Pennsylvania	R-00932665	9/93	Revenue Requirements (Supplemental)	Office of Consumer Advocate
Roaring Creek Water Company	W	Pennsylvania	R-00932665	9/93	Revenue Requirements	Office of Consumer Advocate
Kent County Water Authority	W	Rhode Island	2098	8/93	Revenue Requirements (Surrebuttal)	Division of Public Utilities and Carriers
Wilmington Suburban Water Company	W	Delaware	93-28	7/93	Revenue Requirements	Office of Public Advocate
Kent County Water Authority	W	Rhode Island	2098	7/93	Revenue Requirements	Division of Public Utilities & Carriers
Camden County Energy Recovery Associates, Inc.	SW	New Jersey	SR91111718J ESW1263-92	4/93	Revenue Requirements	Rate Counsel

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Pollution Control Financing Authority of Camden County	SW	New Jersey	SR91111718J ESW 1263-92	4/93	Revenue Requirements	Rate Counsel
Jamaica Water Supply Company	W	New York	92-W-0583	3/93	Revenue Requirements	County of Nassau Town of Hempstead
New Jersey-American Water Company	W/WW	New Jersey	WR92090908J PUC 7266-92S	2/93	Revenue Requirements	Rate Counsel
Passaic County Utilities Authority	SW	New Jersey	SR91121816J ESW0671-92N	9/92	Revenue Requirements	Rate Counsel
East Honolulu Community Services, Inc.	WW	Hawaii	7064	8/92	Revenue Requirements	Division of Consumer Advocacy
The Jersey Central Power and Light Company	E	New Jersey	PUC00661-92 ER91121820J	7/92	Revenue Requirements	Rate Counsel
Mercer County Improvement Authority	SW	New Jersey	EWS11261-91S SR91111682J	5/92	Revenue Requirements	Rate Counsel
Garden State Water Company	W	New Jersey	WR9109-1483 PUC 09118-91S	2/92	Revenue Requirements	Rate Counsel
Elizabethtown Water Company	W	New Jersey	WR9108-1293J PUC 08057-91N	1/92	Revenue Requirements	Rate Counsel
New-Jersey American Water Company	W/WW	New Jersey	WR9108-1399J PUC 8246-91	12/91	Revenue Requirements	Rate Counsel
Pennsylvania-American Water Company	W	Pennsylvania	R-911909	10/91	Revenue Requirements	Office of Consumer Advocate
Mercer County Improvement Authority	SW	New Jersey	SR9004-0264J PUC 3389-90	10/90	Revenue Requirements	Rate Counsel
Kent County Water Authority	W	Rhode Island	1952	8/90	Revenue Requirements Regulatory Policy (Surrebuttal)	Division of Public Utilities & Carriers
New York Telephone	T	New York	90-C-0191	7/90	Revenue Requirements Affiliated Interests (Supplemental)	NY State Consumer Protection Board
New York Telephone	T	New York	90-C-0191	7/90	Revenue Requirements Affiliated Interests	NY State Consumer Protection Board
Kent County Water Authority	W	Rhode Island	1952	6/90	Revenue Requirements Regulatory Policy	Division of Public Utilities & Carriers
Ellesor Transfer Station	SW	New Jersey	SO8712-1407 PUC 1768-88	11/89	Regulatory Policy	Rate Counsel
Interstate Navigation Co.	N	Rhode Island	D-89-7	8/89	Revenue Requirements Regulatory Policy	Division of Public Utilities & Carriers
Automated Modular Systems, Inc.	SW	New Jersey	PUC1769-88	5/89	Revenue Requirements Schedules	Rate Counsel
SNET Cellular, Inc.	T	Connecticut	-	2/89	Regulatory Policy	First Selectman Town of Redding