

Commonwealth of Pennsylvania
Pennsylvania Public Utility Commission
Pike County Light & Power Company

Docket No. _____

GAS

TESTIMONY AND EXHIBITS

Pike County Light & Power Co.
Gas Case

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July 17, 2008

VIA EXPRESS MAIL

Honorable James J. McNulty
Secretary
Commonwealth of Pennsylvania
Pennsylvania Public Utility Commission
400 North Street
Harrisburg, Pennsylvania 17105-3265

Re: Pike County Light & Power Company
Supplement No. 82 to Tariff
Gas - Pa. P.U.C. No. 6

Dear Secretary McNulty:

I enclose for filing on behalf of Pike County Light & Power Company ("Pike" or the "Company") an original and eight copies of Supplement No. 82 to its tariff for gas service, Gas - Pa. P.U.C. No. 6, issued July 18, 2008 to be effective September 16, 2008. Pursuant to the Commission's normal procedures, the Company expects that any rate increase will not become effective until April 2009.

Supplement No. 82 consists of the following tariff leaves:

Supplement No. 82 – Notice	2nd	Revised Leaf No.	40
73rd Revised Leaf No. 2	2nd	Revised Leaf No.	40A
73rd Revised Leaf No. 3	22nd	Revised Leaf No.	44C
14th Revised Leaf No. 4	38th	Revised Leaf No.	45
67th Revised Leaf No. 4A	2nd	Revised Leaf No.	45A
2nd Revised Leaf No. 14	37th	Revised Leaf No.	46
4th Revised Leaf No. 14A	2nd	Revised Leaf No.	46A
3rd Revised Leaf No. 14B			

I also enclose the written pre-filed testimony of the Company's Accounting Panel, Rate Panel and Messrs. Diloreto, Hutcheson and Dr. Morin and supporting schedules, including data required by the Commission's regulations.

Pike is engaged in the retail distribution and sale of natural gas for residential, commercial and industrial purposes within the State of Pennsylvania. Pike serves approximately 1,200 residential and commercial gas customers in Pike County, Pennsylvania.

The increased rates and charges reflected in Supplement No. 82 are designed to produce additional revenues of \$424,900 per year, or approximately 21.4% based on the twelve months ending March 31, 2009. In addition, the Company is proposing an alternative three-year rate plan for its gas operations, which, if adopted, would establish rates for the three-year period ending March 31, 2012. Under the three-year levelized rate proposal advanced by the Company, the levelized annual increase would amount to \$223,900 per year. While the percentage and dollar impacts for the Company's three-year proposal currently are not available, the monthly bill impacts for customers would certainly be much lower under a three-year rate plan than a one year rate plan. The Company expects that the percentage and dollar impacts associated with the Company's three-year proposal will be fully developed through the Commission's rate case process.

Pike requests that Supplement No. 82 become effective on September 16, 2008. Pike's gas base rates were last increased in June 2005. Pike's current gas rates do not produce an adequate return on the Company's invested capital that is dedicated to the service of the Company's gas customers. The proposed rates for gas service are necessary to provide sufficient operating revenues to meet operating expenses (including depreciation), taxes and fixed charges, and provide a reasonable rate of return on the Company's investment in gas property. The proposed rates should be approved to enable Pike to maintain its creditworthiness at a level sufficient to raise capital necessary to perform properly its obligations to provide safe, adequate and proper service to its gas customers.

As set forth in the testimony of the Gas Rate Panel, the bills of all Pike's gas customers will be affected by this rate increase. Appendix A attached hereto sets forth, by service classification, the revenue increases associated with this filing.

As set forth in the testimony of Mr. Hutcheson, Pike also is requesting the Commission's approval to adjust its depreciation rates.

Pike hereby advises the Commission that it has elected to use the method of customer notification set forth in Section 53.45 (b)(2) of the Commission's regulations, 52 Pa. Code § 53.45 (b)(2). I enclose a copy of the Notice of Proposed Rate Changes sent to all Pike gas customers by first class mail on July 17, 2008. Also included is an affidavit stating that the required notice provisions have and will be complied with.

As indicated in the attached Certificate of Service, Pike has served copies of this filing and all supporting data on the Office of Consumer Advocate, as required by Section 53.51(d) of the Commission's regulations, 52 Pa. Code § 53.51 (d), on the Office of Small Business Advocate, and on the Commission's Office of Trial Staff.

While the Commission's regulations do not require the submission of testimony with this filing, in order to explain more fully the details and basis of the rate relief requested, Pike is submitting certain basic testimony. Specifically, as noted above, the Company is presenting the direct testimony of five witnesses. The Accounting Panel will discuss the Company's various financial exhibits, the gas sales forecast, rate case costs, and its proposed three-year rate plan. Richard DiLoreto will discuss the Company's capital expenditures and additions to plant. Charles Hutcheson will discuss his recommendations regarding the Company's depreciation rates. Dr. Roger Morin will testify as to the fair and reasonable rate of return on the common equity capital invested by the Company in its gas delivery operations. The Gas Rate Panel will discuss the Company's Gas Embedded Cost of Service study, the Company's gas revenue forecasts, the Company's proposal for revenue allocation and rate design, the impact of the proposed rate changes on customers' bills, and other tariff changes. Pike specifically reserves the right to submit additional direct testimony in support of this filing.

Pike's legal counsel for this filing are as follows:

John J. Gallagher, Esq.
Saul Ewing, LLP
2 North Second Street, 7th Floor
Harrisburg, PA 17101
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Honorable James J. McNulty

July 17, 2008

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Please date and time-stamp the enclosed extra copy of this letter and return it to me in the envelope provided. If you have any questions regarding the enclosed filing or supporting data, please contact me at (212) 460-3308 or at the address listed above.

Very truly yours,

A handwritten signature in blue ink, appearing to read "Will @ Atzl".

William A. Atzl, Jr.
Director – O&R Rates

Enclosures

c: Certificate of Service

PIKE COUNTY LIGHT AND POWER COMPANY**Impact of Proposed Rate Change on Total Billed Revenue
For the 12 Months Ending March 31, 2009**

<u>Service Class</u>	<u>Type of Service</u>	<u>Annual Bills</u>	<u>Total Sales (CCF)</u>	<u>Total Revenue at:</u>		<u>Increase:</u>	
				<u>Present Rates (\$000)</u>	<u>Proposed Rates (\$000)</u>	<u>Rev Change (\$000)</u>	<u>Percent Change</u>
1	Residential	13,008	1,146,000	1,651.1	2,036.5	385.4	23.3%
2	Commercial	<u>912</u>	<u>238,000</u>	<u>333.5</u>	<u>373.3</u>	<u>39.9</u>	12.0%
Total		<u>13,920</u>	<u>1,384,000</u>	<u>1,984.6</u>	<u>2,409.9</u>	<u>425.3</u>	21.4%

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing document has been served upon the following persons, in the manner indicated, in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant).

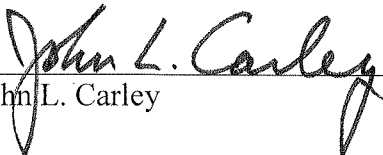
VIA FIRST CLASS MAIL

Irwin A. Popowsky
Consumer Advocate
Office of Consumer Advocate
555 Walnut Street
Forum Place, 5th Floor
Harrisburg, PA 17101-1923

William R. Lloyd, Jr.
Small Business Advocate
Office of Small Business Advocate
Commerce Building Suite 1102
300 North Second Street
Harrisburg, PA 17101

Robert V. Eckenrod, Esquire
Office of Trial Staff
PA Public Utility Commission
Commonwealth Keystone Building
400 North Street, 2nd Floor West
PO Box 3265
Harrisburg, PA 17105-3265

Date: July 18, 2008



John L. Carley

July 17, 2008

NOTICE OF PROPOSED RATE CHANGES

To Our Customers:

Pike County Light & Power Company ("Company") is filing a request with the Pennsylvania Public Utility Commission (PUC) to increase your gas rates as of September 16, 2008. However, the Company anticipates the PUC will follow its normal procedure and suspend rates for nine months, therefore new rates will not become effective until April 2009. This notice describes the Company's rate request, the PUC's role, and what actions you can take.

THE LEVEL OF THE PROPOSED RATE INCREASE

The Company has requested an overall rate increase of \$425,000 per year. If the Company's entire request is approved, the total bill for a residential heating customer using 100 Ccf would increase from \$143.23 to \$176.31 per month or by 23.1%.

The total bill for a commercial customer using 250 Ccf would increase from \$374.99 to \$424.23 per month or by 13.1%.

In addition, the Company is proposing an alternative three-year rate plan for its gas operations, which, if adopted, would establish rates for the three-year period ending March 2012. Under the three-year levelized rate proposal advanced by the Company, the levelized annual increase would amount to \$223,900 per year. While the percentage and dollar impacts for the Company's three-year proposal currently are not available, the monthly bill impacts for customers would certainly be much lower under a three-year rate plan than a one year rate plan.

To find out your customer class or how the requested increase may affect your gas bill, please contact the Company at 1-877-434-4100. The rates requested by the Company may be found in Supplement No. 82 to the Company's gas tariff, Gas – Pa. P.U.C. No. 6. You may examine the material filed with the PUC which explains the requested increase and the reasons for it. A copy of this material is kept at the Company's office located at 311 Broad Street, Milford, Pennsylvania.

THE PROCESS FOR APPROVING THE REQUESTED RATE INCREASE

The state agency which approves rates for public utilities is the PUC. The PUC will examine the requested rate increase and can prevent existing rates from changing until it investigates and/or holds hearings on the request. The Company must prove that the requested rates are reasonable. After examining the evidence, the PUC may grant all, some, or none of the request or may reduce existing rates.

The PUC may change the amount of the rate increase or decrease requested by the Company for each customer class. As a result, the rate charged to you may be different than the rate requested by the Company and shown above.

HOW TO CHALLENGE THE RATE INCREASE

There are three ways to challenge the Company's request to change its rates:

1. You can file a formal complaint. If you want a hearing before a judge, you must file a formal complaint. By filing a formal complaint, you assure yourself the opportunity to take part in hearings about the rate increase request. All complaints should be filed with the PUC before September 16, 2008. If no formal complaints are filed, the Commission may grant all, some or none of the request without holding a hearing before a judge.
2. You can send the PUC a letter telling why you object to the requested rate increase. Sometimes there is information in these letters that makes the PUC aware of problems with the Company's service or management. This information can be helpful when the PUC investigates the rate request.

Send your letter or request for a formal complaint form to the Pennsylvania Public Utility Commission, Post Office Box 3265, Harrisburg, PA 17105-3265.

3. You can be a witness at a public input hearing. Public input hearings are held if the PUC opens an investigation of the Company's rate increase request and if there are a large number of customers interested in the case. At these hearings you have the opportunity to present your views in person to the PUC judge hearing the case and the Company's representatives. All testimony given "under oath" becomes part of the official rate case record. These hearings are held in the service area of the Company.

Pike County Light & Power Company

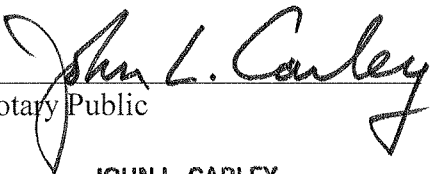
AFFIDAVIT

In accordance with 52 Pa. Code § 53.45 (h), William A. Atzl, Jr., being duly sworn according to law, deposes and says that he is Director, O&R Rates for Pike County Light & Power Company ("Pike"); and that, regarding the gas base rate filing that Pike has requested be effective September 16, 2008, the notice requirements pursuant to 52 Pa. Code § 53.45 et seq. have been met to the best of his knowledge, information and belief.



William A. Atzl, Jr.
Director, O&R Rates

Sworn and subscribed before me
The 17th day of July 2008.


Notary Public

JOHN L. CARLEY
Notary Public, State of New York
No. 4906281
Qualified in Rockland County
Commission Expires August 31, 2009

PIKE COUNTY LIGHT & POWER COMPANY

**RATES AND RULES
GOVERNING THE
FURNISHING OF
GAS SERVICE
IN
THE BOROUGHS OF MATAMORAS AND MILFORD
AND VICINITY,
PIKE COUNTY, PENNSYLVANIA
(See Leaf No. 5)**

ISSUED: July 18, 2008

EFFECTIVE: September 16, 2008

ISSUED BY: John D. McMahon
President
Milford, Pennsylvania

NOTICE

This Supplement increases existing rates. (See Leaf No. 2).

2. CHANGES MADE BY THIS SUPPLEMENT

Supplement No. 82 has been filed to reflect:

- (1) increased Service Charges and Commodity Charges for Service Classifications Nos. 1 and 2;
- (2) a roll in of State Tax Adjustment Surcharge into base rates;
- (3) a revised reconnection charge; and
- (4) the implementation of a late payment charge.

ISSUED: July 18, 2008

EFFECTIVE: September 16, 2008

ISSUED BY: John D. McMahon
President
Milford, Pennsylvania

PIKE COUNTY LIGHT & POWER COMPANY

SUPPLEMENT NO. 82 TO
GAS - PA. P.U.C. NO. 6

73rd REVISED LEAF NO. 3
SUPERSEDING 72nd REVISED LEAF NO. 3

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(Continued)

ISSUED: July 18, 2008

EFFECTIVE: September 16, 2008

ISSUED BY: John D. McMahon
President
Milford, Pennsylvania

PIKE COUNTY LIGHT & POWER COMPANY

14th REVISED LEAF NO. 4
SUPERSEDING 13th REVISED LEAF NO. 4

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(Continued)

ISSUED: July 18, 2008

EFFECTIVE: September 16, 2008

ISSUED BY: John D. McMahon
President
Milford, Pennsylvania

PIKE COUNTY LIGHT & POWER COMPANY

67th REVISED LEAF NO. 4A
SUPERSEDING 66th REVISED LEAF NO. 4A

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ISSUED:	July 18, 2008	EFFECTIVE:	September 16, 2008
ISSUED BY:	John D. McMahon President Milford, Pennsylvania		

PIKE COUNTY LIGHT & POWER COMPANY

2nd REVISED LEAF NO. 14
SUPERSEDING 1st REVISED LEAF NO. 14

RULES AND REGULATIONS

9. METERING AND BILLING (Continued)

9.5 RENDERING OF BILLS

Rates and Charges are stated on a monthly basis as set forth in the Service Classifications. For billing purposes, a monthly period will be considered as 26 - 35 days. In determining the charges for billing periods other than a monthly period, the monthly rates, as stated in the Service Classification, are prorated on the basis of thirtieths of a month.

Bills for service will be rendered monthly. Bills for residential service for any month in which no meter reading is taken are rendered on an estimated basis. When the Company is unable to obtain meter readings on regular reading dates, bills are rendered (1) on readings by Customers if said readings are received on or before the date shown on the meter indexing card, or (2) on estimated readings. Amounts billed on the basis of such estimates are subject to adjustment in accordance with the next meter readings obtained by the Company.

In case any meter for any reason fails to register the full use of service by the Customer for any period of time, the usage of service by the Customer for the period may be estimated by the Company on the basis of available data, and the Customer billed accordingly.

9.6 LATE PAYMENT CHARGE (C)

The Company may impose late payment charges on any bill not paid within five days of the due date at the rate of one and one-half percent (1.5%) per month on the overdue balance of the bill. The interest rate, when annualized, will not exceed 18% simple interest per annum.

9.7 CHANGE OF RATE (C)

Service Classifications and Rules and Regulations under which Customers are served are subject to such changes as may be lawfully made. Customers taking service under a rate schedule so revised shall thereafter take and pay for service in accordance with the provisions of the revised or superseding schedules so established.

(C) Indicates Change

(Continued)

ISSUED:	July 18, 2008	EFFECTIVE:	September 16, 2008
ISSUED BY:	John D. McMahon President Milford, Pennsylvania		

PIKE COUNTY LIGHT & POWER COMPANY

4th REVISED LEAF NO. 14A
SUPERSEDING 3rd REVISED LEAF NO. 14A

RULES AND REGULATIONS

9. METERING AND BILLING (Continued)

9.8 BUDGET BILLING

(C)

- (1) All residential and non-residential customers, unless otherwise prohibited, may elect to pay for service taken in accordance with the following provisions:
 - a. The customer will make equal monthly payments during the Budget
 - b. If at the end of the Budget Year, the amount paid by the customer is less than the amount due for actual service rendered:
 - (i) the balance due for residential customers, customers who are a condominium association, cooperative housing corporation, and master metered gas heated multifamily dwelling units during the time that such units are either owned by the Federal Department of Housing and Urban Development or subject to a first mortgage held or guaranteed by that agency shall be billed to and payable by the customer during the next six monthly billing periods; or
 - (ii) the balance due for all other customers will be billed in the month ending the budget year and shall be payable by the customer in full at that time.
 - c. If at the end of the Budget Year, the amount paid by the customer is greater than the amount due for actual service rendered, the Company shall apply a credit to the customer's account equal to the amount overpaid or, at the customer's request, shall refund an amount equal to the overpayment.
- (2) The Budget Year will be the twelve-month period beginning with the billing month the customer initially enrolls in budget billing.

(C) Indicates Change

(Continued)

ISSUED: July 18, 2008

EFFECTIVE: September 16, 2008

ISSUED BY: John D. McMahon
President
Milford, Pennsylvania

PIKE COUNTY LIGHT & POWER COMPANY

3rd REVISED LEAF NO. 14B
SUPERSEDING 2nd REVISED LEAF NO. 14B

RULES AND REGULATIONS

9. METERING AND BILLING (Continued)

9.8 BUDGET BILLING (Continued) (C)

- (3) The monthly budget payment will normally be adjusted at the end of the Budget Year to reflect any changes in the Company's charges or the customer's usage during the Budget Year. The Company may also adjust the monthly budget payment during the Budget Year should conditions warrant a change.
- (4) When a customer elects budget billing for both gas and electric service, the monthly budget payment will be based on the combined cost of providing gas and electric service.
- (5) Should a customer fail to make a monthly budget payment when due, the Company shall have the right to cancel the budget billing plan. Upon cancellation any overpayment will be credited to the customer's account and any deficiency shall be due and payable.

(C) Indicates Change

ISSUED:	July 18, 2008	EFFECTIVE:	September 16, 2008
ISSUED BY:	John D. McMahon President Milford, Pennsylvania		

PIKE COUNTY LIGHT & POWER COMPANY

2nd REVISED LEAF NO. 40
SUPERSEDING 1st REVISED LEAF NO. 40

RULES AND REGULATIONS

15. RESTORATION OF SERVICE

15.1 RESTORATION OF SERVICE

(C)

(A) Requirements for Residential Reconnection

When service to a dwelling has been terminated, the Company shall inform the applicant or residential customer where payment can be made to restore service and shall reconnect service after receiving:

- (1) Full payment of any outstanding charges plus a reconnection fee of \$27.00 if the residential customer or applicant has a household income exceeding 300 percent of the Federal Poverty Level or has defaulted on 2 or more payment agreements. If an applicant or residential customer with household income exceeding 300 percent of the Federal Poverty Level experiences a life event the residential customer or applicant shall be permitted a period of not more than 3 months to pay the outstanding balance required for reconnection. For purposes of this paragraph, a life event is a job loss that extended beyond 9 months, a serious illness that extended beyond nine months, or death of the primary wage earner; or
- (2) Full payment over 12 months of any outstanding charges plus a reconnection fee of \$27.00 if the residential customer or applicant has a household income exceeding 150 percent of the Federal Poverty Level but not greater than 300 percent of the Federal Poverty Level; or
- (3) Full payment over 24 months of any outstanding charges plus a reconnection fee of \$27.00 if the residential customer or applicant has a household income not exceeding 150 percent of the Federal Poverty Level; or
- (4) Payment of any outstanding balance or payment of a portion of the outstanding balance if the applicant resided at the premises for which service is being requested during the time that the outstanding balance accrued. The Company may establish that the applicant resided at the premises for which service is requested through the use of mortgage, deed, or lease information or a commercially available credit reporting service or by other methods approved by the Commission.

(B) Requirements for Non-Residential Reconnection

When service to a non-residential building has been terminated, the Company shall inform the applicant where payment can be made to restore service and shall reconnect service after receiving full payment of any outstanding charges plus a reconnection fee of \$27.00.

(C) Indicates Change

(Continued)

ISSUED: July 18, 2008

EFFECTIVE: September 16, 2008

ISSUED BY: John D. McMahon
President
Milford, Pennsylvania

PIKE COUNTY LIGHT & POWER COMPANY

2nd REVISED LEAF NO. 40A
SUPERSEDING 1st REVISED LEAF NO. 40A

RULES AND REGULATIONS

15. RESTORATION OF SERVICE (Continued)

15.1 RESTORATION OF SERVICE (Continued) (C)

(C) Timing of Reconnection

The Company shall restore service provided that the applicant has met all conditions for the restoration of service, as follows:

- (1) Within 24 hours for erroneous terminations or upon receipt by the Company of a valid medical certification,
- (2) Within 24 hours for termination occurring after November 30 and before April 1,
- (3) Within three days for erroneous terminations requiring street or sidewalk digging,
- (4) Within three days from April 1 to November 30 for proper terminations,
- (5) Within seven days for proper terminations requiring street or sidewalk digging.

15.2 PERSONNEL AVAILABLE TO RESTORE SERVICE

The Company shall have adequate personnel available between 9 a.m. and 5 p.m. on each working day, or for a commensurate period of eight consecutive hours, to restore service when required under this Section.

(C) Indicates Change

ISSUED:	July 18, 2008	EFFECTIVE:	September 16, 2008
ISSUED BY:	John D. McMahon President Milford, Pennsylvania		

PIKE COUNTY LIGHT & POWER COMPANY

22nd REVISED LEAF NO. 44C
SUPERSEDING 21st REVISED LEAF NO. 44C

STATE TAX ADJUSTMENT SURCHARGE

In addition to the charges provided in this tariff, except for charges or credits applied under the Gas Cost Rate, the Take or Pay Surcharge, and/or the Income Tax Adjustment, an adjustment of 0.00% will be applied for all service rendered on and after the effective date of this leaf. (I)

The State Tax Adjustment Surcharge will be recomputed using the elements prescribed by the Commission whenever the Company experiences a material change in any of the taxes used in calculation of the surcharge. Such recalculation will be submitted to the Commission within 10 days after the occurrence of the event which occasions such recomputation. If the recomputed surcharge is less than the one in effect the utility will, or if the recomputed surcharge is more than the one in effect the utility may, submit with such recomputation a tariff or supplement to reflect such recomputed surcharge. The effective date of such tariff or supplement shall be ten days after filing. Any charges or credits in the surcharge shall be rolled into base rates in the Company's next base rate proceeding.

(I) Indicates Increase

ISSUED:	July 18, 2008	EFFECTIVE:	September 16, 2008
ISSUED BY:	John D. McMahon President Milford, Pennsylvania		

PIKE COUNTY LIGHT & POWER COMPANY

38th REVISED LEAF NO. 45
SUPERSEDING 37th REVISED LEAF NO. 45

SERVICE CLASSIFICATION NO. 1

APPLICABLE TO USE OF SERVICE FOR:

Residential Service and Residential Space Heating Service

RATE - FIVE PART - MONTHLY:

- (1) Service Charge \$ 6.29 (I)
- (2) Commodity Charge
All Ccf @ 155.26¢ per Ccf (I)
- (3) Gas Cost Rate
All sales made hereunder shall be subject to the Gas Cost Rate as explained in Rider A of this tariff.
- (4) Take-or-Pay Recovery Surcharge
All sales made hereunder shall be subject to the Take-or-Pay Recovery Surcharge as explained in Rider B of this tariff.
- (5) State Tax Adjustment Surcharge
The State Tax Adjustment Surcharge included in this Tariff is applied to charges under this rate except for charges made under the Gas Cost Rate.

MINIMUM CHARGE EACH CONTRACT EACH LOCATION:

Not less than \$6.29 net per month during which service is furnished to a Customer at each location. (I)

TERMS OF PAYMENT:

Bills are due and payable on or before twenty days from date bill is mailed to Customer. If bill is not paid within twenty days, service may be discontinued after suitable written notice as outlined in the Rules and Regulations.

(I) Indicates Increase

(Continued)

ISSUED: July 18, 2008

EFFECTIVE: September 16, 2008

ISSUED BY: John D. McMahon
President
Milford, Pennsylvania

PIKE COUNTY LIGHT & POWER COMPANY

2nd REVISED LEAF NO. 45A
SUPERSEDING 1st REVISED LEAF NO. 45A

SERVICE CLASSIFICATION NO. 1 (Continued)

TERM:

Terminable at any time unless a specified period is required under a main extension agreement.

SPECIAL PROVISIONS:

Budget Billing Plan:

(C)

Any customer taking service hereunder may, upon request, be billed monthly in accordance with the budget billing plan provided for in Section 9.8 of the Rules and Regulations.

(C) Indicates Change

ISSUED:	July 18, 2008	EFFECTIVE:	September 16, 2008
ISSUED BY:	John D. McMahon President Milford, Pennsylvania		

PIKE COUNTY LIGHT & POWER COMPANY

37th REVISED LEAF NO. 46
SUPERSEDING 36th REVISED LEAF NO. 46

SERVICE CLASSIFICATION NO. 2

APPLICABLE TO USE OF SERVICE FOR:

General Service and Non-Residential Space Heating Service

RATE - FIVE PART - MONTHLY:

(1) Service Charge \$ 9.43 (I)

(2) Commodity Charge

First 300 Ccf. @ 151.15¢ per Ccf (I)
All Over 300 Ccf. @ 135.77¢ per Ccf (I)

(3) Gas Cost Rate

All sales made hereunder shall be subject to the Gas Cost Rate as explained in Rider A of this tariff.

(4) Take-or-Pay Recovery Surcharge

All sales made hereunder shall be subject to the Take-or-Pay Recovery Surcharge as explained in Rider B of this tariff.

(5) State Tax Adjustment Surcharge

The State Tax Adjustment Surcharge included in this tariff is applied to charges under this rate except for charges made under the Gas Cost Rate.

MINIMUM CHARGE EACH CONTRACT EACH LOCATION:

Not less than \$9.43 net per month during which service is furnished to a Customer at each location. (I)

TERMS OF PAYMENT:

Bills are due and payable on or before fifteen days from date bill is mailed to Customer. If bill is not paid within fifteen days, service may be discontinued after suitable written notice as outlined in the Rules and Regulations.

(I) Indicates Increase

(Continued)

ISSUED:	July 18, 2008	EFFECTIVE:	September 16, 2008
ISSUED BY:	John D. McMahon President Milford, Pennsylvania		

PIKE COUNTY LIGHT & POWER COMPANY

2nd REVISED LEAF NO. 46A
SUPERSEDING 1st REVISED LEAF NO. 46A

SERVICE CLASSIFICATION NO. 2 (Continued)

TERM:

Terminable at any time unless a specified period is required under a main extension agreement.

SPECIAL PROVISIONS:

Budget Billing Plan:

(C)

Any customer who takes service hereunder may, upon request, be billed monthly in accordance with the budget billing plan provided for in Section 9.8 of the Rules and Regulations.

(C) Indicates Change

ISSUED:	July 18, 2008	EFFECTIVE:	September 16, 2008

ISSUED BY:	John D. McMahon President Milford, Pennsylvania

**PIKE COUNTY LIGHT & POWER COMPANY
GAS RATE CASE
DIRECT TESTIMONY OF
ACCOUNTING PANEL**

1 Q. Would the members of the Accounting Panel please state
2 your names and business addresses.

3 A. Kenneth A. Kosior, One Blue Hill Plaza, Pearl River,
4 New York 10965.

5 Richard A. Kane, 4 Irving Place, New York, New York
6 10003.

7 Stephen D. Prager, 4 Irving Place, New York, New York
8 10003.

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

10 A. **(Kosior)** I am employed by Orange and Rockland
11 Utilities, Inc. ("Orange and Rockland" or "O&R") where
12 I hold the position of Director - Financial Services.

13 **(Kane)** I am employed by Consolidated Edison Company of
14 New York, Inc. ("Con Edison"), where I hold the
15 position of Department Manager of Regulatory Filings.

16 **(Prager)** I am employed by Con Edison where I hold the
17 position of Senior Accountant in Regulatory Filings.

18 Q. Please explain your educational background, work
19 experience, and current general responsibilities.

20 A. **(Kosior)** I graduated from Pace University in 1976 with
21 a Bachelor of Business Administration degree, having
22 majored in Accounting. In June 1980, I received a
23 Masters of Business Administration degree from

ACCOUNTING PANEL

1 Fairleigh Dickinson University, having majored in
2 Accounting and Finance. After graduation from Pace, I
3 was employed by Homa Company as a staff accountant. I
4 joined Orange and Rockland in July 1979 as an Associate
5 Accountant advancing to Supervisor-Payroll, Supervisor
6 & Manager-General Accounting where I had the
7 responsibility of administering and supervising all
8 employee related payroll records and subsequently the
9 books and records of Orange and Rockland and its
10 subsidiaries, including Pike County Light & Power
11 Company ("Pike" or the "Company"). In June 1989, I was
12 promoted to Manager-Budgets and was responsible for the
13 development and management of the operating and capital
14 budgets. My additional duties included forecasting and
15 analyzing the corporate financial statements. I was
16 named Strategic Analysis Principal in October 1994 and
17 became responsible for developing, analyzing and
18 evaluating corporate direction and business
19 opportunities. In June 1995, I was promoted to
20 Director of Accounting, where I was responsible for the
21 accounting functions of Orange and Rockland and its
22 subsidiaries, including the consolidated financial
23 statements. In July 1999, as a result of the merger
24 involving Con Edison and Orange and Rockland, I was
25 appointed Director-Financial Planning and

ACCOUNTING PANEL

1 Administration, now called Financial Services,
2 responsible for providing the coordination for
3 administration, financial, budget and regulatory
4 activities between Con Edison and Orange and Rockland.
5 I have been a member of various accounting and finance
6 committees of the Edison Electric Institute and
7 Pennsylvania Electric Association. In addition, I am a
8 past Chairperson of the New Jersey Utilities
9 Association Accounting and Finance Committee.

10 **(Kane)** I received a Bachelor of Science degree in
11 Accounting from Manhattan College in May 1976. I
12 worked for Con Edison from August 1976 until January
13 1978, as a staff accountant. I then joined Orange and
14 Rockland and became Supervisor - Facility Accounting.
15 In 1980, I became Manager - Budgets. In 1989, I became
16 Manager - General Accounting, and in 1996, the Accounts
17 Payable Section was added to my responsibilities. As a
18 result of the merger involving Orange and Rockland and
19 Con Edison, Orange and Rockland's Accounting Department
20 was combined with Con Edison's and relocated to Con
21 Edison's headquarters in New York City. Since the
22 merger, I continued to be responsible for overseeing
23 Orange and Rockland's General Accounting Section and
24 Financial Reporting area until March 2003. At that
25 time, I assumed my current position as Manager of the

ACCOUNTING PANEL

1 Regulatory Filing Section within Con Edison's Corporate
2 Accounting Department where I oversee rate case revenue
3 requirement calculations and supporting documentation
4 as well as Accounting Petitions filed in New York, New
5 Jersey and Pennsylvania.

6 **(Prager)** I received a Bachelor of Science degree in
7 Accounting from Yeshiva University in 1988. I started
8 my career at Con Edison in July 1988 as a management
9 intern. From July 1989 through September 1998, I worked
10 in Accounting Research and Procedures. From October
11 1998 through March 2000, I worked in General Accounts.
12 Since April 2000, I have been working in Regulatory
13 Filings, coordinating the rate cases of Con Edison and
14 Orange and Rockland and its subsidiaries.

15 Q. Have you previously submitted testimony before the
16 Pennsylvania Public Utility Commission ("PAPUC")?

17 A. **(Kosior)** Yes. I submitted testimony in Docket No. R-
18 00049884.

19 **(Kane)** Yes. I submitted testified in Docket No. R-
20 00049884.

21 **(Prager)** No.

22 Q. What is the purpose of the Accounting Panel's testimony
23 in this proceeding?

24 A. The Accounting Panel is sponsoring Exhibits G-1 through
25 G-5, which explain and detail the following:

ACCOUNTING PANEL

- 1 • Historic financial data (Exhibit G-1);
- 2 • Actual and forecast capital structures and rate of
- 3 return (Exhibit G-2);
- 4 • Historic and forecast gas rate base (Exhibit G-3);
- 5 • Historic and forecast cost of service (Exhibit G-4);
- 6 • The Company's three-year rate proposal (Exhibit G-
- 7 5); and
- 8 • The Company's gas sales (Exhibit G-6), Schedules 1
- 9 and 2.

10 Q. Is the Accounting Panel familiar with Pike's books and
11 records, as well as the Joint Operating Agreement
12 ("JOA") between Pike and Orange and Rockland, pursuant
13 to which certain costs, including but not limited to,
14 wage, salary and payroll taxes, are allocated to Pike?

15 A. Yes.

16 Q. Are the accounts of the Company kept in accordance with
17 the Uniform System of Accounts as prescribed by the
18 PAPUC?

19 A. Yes.

20

21 **EXHIBIT G-1, HISTORICAL FINANCIAL DATA**

22 Q. Please describe Exhibit G-1.

23 A. Exhibit G-1 contains the historic financial data for
24 Pike as required by PAPUC regulations. Schedule 1
25 shows the balance sheets of Pike at March 31, 2007 and

ACCOUNTING PANEL

1 March 31, 2008. Schedule 2 provides the account
2 balances comprising the Company's net investment in
3 electric and gas utility plant in service at March 31,
4 2008. Schedule 3 is an income statement that shows the
5 derivation of net income for electric and gas
6 operations for the year ended March 31, 2008. Schedule
7 4 is a comparative income statement for Pike's gas
8 operations for the twelve months ended March 31, 2007
9 and March 31, 2008. Schedule 5 shows the intercompany
10 charges billed to Pike under the provisions of the JOA
11 for the twelve months ended March 31, 2008.

Joint Operating Agreement

13 Q. Please describe Exhibit G-1, Schedule 5 in more detail.

14 A. Exhibit G-1, Schedule 5, "Statement of Charges Made by
15 Orange and Rockland Utilities, Inc. to Pike County
16 Light & Power Company Gas Operations under the Terms of
17 the Joint Operating Agreement", is submitted in support
18 of the charges for gas operations billed by Orange and
19 Rockland to Pike in accordance with the terms of the
20 JOA. The schedule sets forth by prime account each
21 item for which a direct charge is made or which was the
22 result of an allocation.

23 Q. What types of services are billed by Orange and
24 Rockland to Pike based on direct charges?

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1 A. Pursuant to the JOA, billings are made on a direct
2 charge basis for services rendered by O&R to Pike
3 whenever it is practical, based on payroll records,
4 direct payments to vendors and contractors, and usage
5 studies supporting the distribution of clearing
6 accounts. The direct charge billings are for
7 activities and services rendered that are for the
8 exclusive benefit of Pike's customers, such as the
9 operation and maintenance ("O&M") of Pike's gas
10 distribution facilities, construction or purchase of
11 utility plant, and other services required for
12 operation.

Cost Allocation Methods

14 Q. Please describe the types of costs allocated by O&R to
15 Pike and the methods of allocation used.

16 A. The types of costs allocated and the basis for such
17 allocations are defined in Article 2 of the JOA. Costs
18 that are impractical to charge on a direct basis, such
19 as administrative and general, collection of customer
20 billings, meter reading, customer accounting and
21 customer services charges are allocated to Pike based
22 on the relationship, during the preceding calendar
23 year, of the revenues of Pike to the total revenues of
24 O&R and its utility subsidiaries. For purposes of
25 these calculations, revenue is defined as revenue from

ACCOUNTING PANEL

ultimate customers, net of fuel cost recoveries. For 2008, the ratios are as follows:

A0 Ratio

$$\frac{\text{Pike Gas Revenue}}{\text{Total Consolidated Net Revenue}} = \frac{\$441,000}{\$403,085,000} = 0.11\%$$

The A0 ratio is used to distribute costs that are common to the electric and gas operations of O&R and all its utility subsidiaries.

D0 Ratio

$$\frac{\text{Pike Gas Revenue}}{\text{Total Net Revenue of O\&R and Pike}} = \frac{\$441,000}{\$310,816,000} = 0.14\%$$

The D0 ratio is used to distribute costs that are common to the electric and gas operations of O&R and Pike.

G0 Ratio

$$\frac{\text{Pike Gas Revenue}}{\text{Total Net Gas Revenue-O\&R \&Pike}} = \frac{\$441,000}{\$104,537,000} = 0.42\%$$

The G0 ratio is used to distribute costs that are common to the gas operations of O&R and all its utility subsidiaries.

In addition, Pike owns its proportionate share of the general materials and supplies inventory, the allocation of which is determined as follows:

- (1) General gas stock items are allocated on the ratio of the number of Pike gas customers to the total number of gas customers of O&R and its utility subsidiaries at the end of the preceding year. For 2008, this ratio allocates 0.9201% to Pike gas operations.

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1 (2) Common stock items usable in both electric and gas
2 operations such as gasoline, small tools, and
3 undistributed storeroom expenses are allocated on
4 the ratio of the number of Pike customers to the
5 total number of electric and gas customers of O&R
6 and its utility subsidiaries at the end of the
7 preceding calendar year. For 2008, this ratio
8 allocates 1.3575% to Pike gas operations.

9 With regard to Federal income taxes, O&R and its
10 subsidiaries file a consolidated Federal Income tax
11 return and any tax liability or benefit is allocated
12 among O&R and its subsidiaries as provided for in
13 Section 1152-1 (a)(2) of the Internal Revenue Code of
14 1954. Tax liabilities or benefits are computed and
15 allocated to each company on the separate return basis,
16 with tax liabilities or benefits allocated to the
17 company that generated the liability or benefit, and
18 each company's tax liabilities never exceeds its
19 separate return liability.

21 **EXHIBIT G-2, CAPITALIZATION AND RATE OF RETURN**

22 Q. Please describe Exhibit G-2.

23 A. Exhibit G-2 shows the actual and forecast capital
24 structures.

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1 Q. What capital structure is Pike requesting in this
2 proceeding?

3 A. The Company is requesting an average capital structure
4 for March 31, 2009 as shown below:

	<u>Ratio</u>
Long-Term Debt	48.03%
Common Equity	<u>51.97%</u>
Total	<u>100.00%</u>

9
10 Q. Do you believe that this is a reasonable capital
11 structure to be employed in this proceeding?

12 A. Yes, we do.

13 Q. Please explain why this capital structure is
14 appropriate?

15 A. It reflects the forecast ratios of capital being
16 employed by O&R, Pike's parent company, as set forth on
17 Exhibit G-2, Schedule 1 for the twelve months ending
18 March 31, 2009. The capital structure reflects the
19 proportions of the actual capital being used in the
20 utility's business plus projected financings. We would
21 note that Exhibit G-2, Schedule 2, which sets forth the
22 long-term debt of O&R and its subsidiaries, assumes
23 that O&R will be issuing \$50 million of long-term debt
24 at 6.10% in August 2008 and \$50 million of long-term
25 debt at 6.74% in September 2008. Given the timing of
26 the planned financings, we will update the capital

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structure for actual amount and cost of the new debt issues during the course of this proceeding. This capital structure is reasonable when compared to the capital structure of the proxy companies used in Dr. Morin's cost of equity analysis. The actual Value Line capital structure for these companies for 2007 and projected 2013 median capital structure ratios for the proxy group are summarized below:

	<u>2007</u>	<u>2013</u>
Long-Term Debt	54.0%	49.5%
Preferred Stock	0.5	0.5
Common Equity	<u>45.7</u>	<u>50.0</u>
Total	<u>100%</u>	<u>100%</u>

Q. What is your conclusion as to the reasonableness of Pike's requested common equity ratio in this proceeding?

A. Based on the above analysis and discussion, we conclude that the 51.97 percent common equity ratio requested by Pike in this proceeding is reasonable. The requested equity ratio reflects the parent company's forecast common equity ratio and that equity ratio is in line with proxy group and subsidiary utility companies and thus is appropriate to use in this proceeding.

Q. Does the capital structure reflect the cost of equity return recommended by Company witness Morin of 10.9

ACCOUNTING PANEL

1 percent?

2 A. No, in order to mitigate the size of the rate increase
3 the Company is seeking for its gas operations we are
4 requesting a return on equity of 10.0 percent.

5 Lowering the requested return on equity by 90 basis
6 points decreased the requested rate increase by
7 \$12,600.

8 Q. What is the overall rate of return ("ROR") the Company
9 is requesting?

10 A. As shown on Exhibit G-2, Schedule 3, the overall ROR is
11 8.21 percent.

12

13 EXHIBIT G-3, GAS RATE BASE

14 Q. Please describe Exhibit G-3.

15 A. Exhibit G-3 consists of a summary and seven schedules
16 containing Pike's historic and future gas rate base.

17 Q. Please describe the method used to calculate the
18 historic gas rate base at March 31, 2008 as shown on
19 the summary page.

20 A. We began with actual gas utility plant and plant
21 reserves to arrive at net plant at March 31, 2008. To
22 net plant, we added cash working capital, materials and
23 supplies, and prepayments. Finally, we deducted
24 accumulated deferred income taxes to arrive at gas rate
25 base.

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1 Q. Please describe the method used to calculate the
2 forecast gas plant balance at September 30, 2009.

3 A. We began with the actual gas plant in service balance
4 per books at March 31, 2008. Mr. DiLoretto provided us
5 with the budgeted gas distribution additions scheduled
6 for April 1, 2008 through September 30, 2009.
7 Retirements were projected through September 30, 2009
8 and are based on a five year historical average. The
9 calculated adjustment of \$161,900 is shown on Exhibit
10 G-3, Schedule 1, Page 1.

11 Q. Please describe the method used to calculate the
12 forecast common plant balance at March 31, 2009.

13 A. The Company did not have any common plant in service
14 balance on its books at March 31, 2008. In April 2008,
15 the Company rented and occupied a new office in
16 Milford, Pennsylvania to provide customer service. The
17 Company spent \$50,000 on furniture, leasehold
18 improvements and equipment. The allocation to gas of
19 \$10,100 is shown on Exhibit G-3, Schedule 1, Page 2.

20 Q. Please describe the calculation of the accumulated
21 provision for depreciation of gas plant in service for
22 the period ending September 30, 2009.

23 A. We began with the per books balance at March 31, 2008,
24 added accruals projected through September 30, 2009 and
25 subtracted retirements for the same period to arrive at

ACCOUNTING PANEL

1 the ending balance at September 30, 2009. The
2 calculated adjustment of \$32,700 is shown on Exhibit G-
3 3, Schedule 2, Page 1.

4 Q. Please describe the \$3,700 increase to the reserve
5 balance as shown on Exhibit G-3, Schedule 2, Page 1.

6 A. We began with the forecasted gas plant in service
7 balance at September 30, 2009. We then multiplied that
8 amount by the proposed composite book depreciation rate
9 of 1.72% to arrive at our proposed accrual to the
10 depreciation reserve of \$32,500. This represents a
11 \$2,800 increase to the reserve as the projected accrual
12 for the period April 1, 2008 – March 31, 2009, as shown
13 at the top of Exhibit G-3, Schedule 2, Page 1.

14 Q. Please continue.

15 A. We made a second adjustment to the reserve balance for
16 the difference between the book and theoretical
17 reserve. This adjustment is also shown on Exhibit G-3,
18 Schedule 2, Page 1. The depreciation reserve based on
19 proposed rates would be \$390,585, which is \$36,347 more
20 than the actual book reserve balance. Gas Plant has an
21 average age of 17 years compared to a composite book
22 life for this plant of 57 years. We therefore
23 amortized the excess depreciation reserve over the
24 remaining life of the plant, i.e., 40 years. This
25 results in a \$900 increase to the reserve. The net of

ACCOUNTING PANEL

1 the two adjustments is a \$3,700 increase to the
2 reserve.

3 Q. Please describe the calculation of the accumulated
4 provision for depreciation of common plant in service
5 for the period ending March 31, 2009.

6 A. The Company did not have any accumulated provision for
7 depreciation of common plant in service balance on its
8 books at March 31, 2008. As stated above, the Company
9 projects to spend \$50,000 on furniture and equipment at
10 its office in Milford. The allocation to gas of the
11 related accumulated depreciation of \$2,000 is shown on
12 Exhibit G-3, Schedule 2, Page 2.

13 Q. How did you calculate the cash working capital for the
14 twelve months ending March 31, 2009?

15 A. We prepared a lead/lag study, which is shown on Exhibit
16 G-3, Schedule 3, Page 1 of 3.

17 Q. Please provide an overview of the lead/lag study and
18 describe its results.

19 A. The lead/lag study utilizes accounting information and
20 financial studies for the twelve months ended December
21 31, 2007 to determine the net lag days. The net lag
22 days are applied to the cost of service inputs for the
23 rate year ending March 31, 2009, in order to determine
24 the cash working capital requirements reflected in rate
25 base. The study indicates a cash working capital

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1 requirement of \$61,904, as shown on Exhibit G-3,
2 Schedule 3, Page 1. The purpose of the cash working
3 capital component of rate base is to compensate the
4 Company for funds it provides to pay operating expenses
5 in advance of receipt of revenue. It reflects the
6 amount of capital over and above investment in plant
7 and other separately identified rate base items
8 provided by the Company to bridge the gap between the
9 time the Company provides service and the time the
10 Company collects revenue for that service. A lead or
11 lag reflects the amount of time that elapses between
12 when a party provides a product or service, and when
13 that providing party is compensated for the product or
14 service provided. For the purpose of this study, the
15 amount of lead or lag times was calculated in days.

16 Q. Please describe the revenue component of the lead/lag
17 study.

18 A. The lag on revenue collection consists of three
19 components:

- 20 • the time between rendering of service and meter
21 reading;
- 22 • the time between meter reading and billing of
23 services; and
- 24 • the time between billing of services and
25 collection of revenue.

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1 Pike's customers are billed on a monthly cycle.
2 The average time from the rendering of service to meter
3 reading date is calculated to be 15.2 days. The 15.2
4 days was calculated by dividing 365 days by twelve
5 months and then dividing by two to achieve the mid-
6 point for each monthly service period ($365 / 12 = 30.4$
7 $/ 2 = 15.2$). Based on an examination of the meter
8 reading and billing data for the year ended December
9 31, 2007, on average, it took 1.5 days from the time
10 meters were read to the time bills were generated and
11 mailed out. Generally, billing occurs the same day the
12 meter reading is completed for that particular cycle,
13 with mailing occurring the following day. The billing
14 to collection lag was determined by analyzing one
15 month's payments for each quarter of 2007 (i.e.,
16 January, April, July and October). Average lag days
17 were generated for each revenue class of billing and
18 weighted by their amounts. Based on this analysis, on
19 average, bills were outstanding for 26.9 days.
20 Combined, the total lag in revenue recovery of energy
21 bills and miscellaneous operating revenues is 43.6
22 days.

23 Q. Please describe the treatment of cost of service in the
24 study.

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1 A. The cost of service was broken down into the basic
2 components of operating expense and operating income.
3 Operating income, which represents a return on invested
4 capital, is included as a component of the cost of
5 service.

6 Q. Please describe the treatment of gas supply expenses in
7 the study.

8 A. The cost of gas supply expenses allocated to Pike by
9 O&R in accordance with the terms of the JOA, are the
10 basis for the lead/lag on gas supply costs. Under the
11 JOA, there is a 45-day lag based on the payment terms
12 included in the agreement. The JOA states that
13 payments are due 30 days after the month in which
14 services were rendered. The lag is measured from the
15 mid-point of the month ($30 \text{ days} / 2 = 15$) to the date
16 of payment for services (30 days), totaling 45 days.

17 Q. Please describe the treatment of salaries and wages.

18 A. The lag for salaries and wages, reflecting both weekly
19 and semi-monthly employees, was calculated to be 8.1
20 days. Weekly employees are paid on the Thursday
21 following the week worked resulting in an 8.5-day lag
22 (service period 7 days / 2 = 3.5 day midpoint + 5 days
23 until checks are received). Semi-monthly employees are
24 paid the 15th and 30th of every month for their prior
25 two weeks worked resulting in a 7.6-day lag. The two

ACCOUNTING PANEL

1 payroll schedules weighted by dollars charged to O&M
2 expense for the twelve months ended December 31, 2007
3 produce an 8.1-day lag.

4 Q. Please describe the lag days associated with pensions.

5 A. A zero lag is assigned to fund contributions and
6 supplemental expenses. The lag on 401K matching
7 contributions is 8.1 days based on the salary and wages
8 lag since it is paid on the same days checks are
9 distributed to weekly and semi-monthly employees. The
10 net lag is 0.4 days.

11 Q. Please describe the lags associated with other post
12 employment benefits ("OPEBs") and employee welfare
13 expenses.

14 A. The lag on OPEBs is a result of the weighted average
15 lags on pay-as-you-go health insurance expense and
16 OPEBs. Pay-as-you-go health insurance expense has a
17 zero lag, as it is a non-cash item. The lag for OPEBs
18 expense was calculated to be 79.5 days. The Company
19 makes three payments annually to the OPEB trust, a 50%
20 contribution on or about August 15th, 25% on or about
21 October 15th, and the remaining 25% on or about
22 December 15th. A mid-point was determined for each of
23 the respective pay periods and then weighted against
24 their payment allocation for total lag of 79.5 days.
25 The lag on employee welfare expenses is a result of the

ACCOUNTING PANEL

1 weighted average lags on health and life insurance
2 premiums and miscellaneous employee welfare expenses.
3 An analysis of payments to health and life insurance
4 carriers was conducted for 2007 by analyzing premiums
5 paid and calculating a lag from each service period
6 (mid-point) to the pay date resulting in a lag of 12.1
7 days. Miscellaneous employee welfare expense utilized
8 the same 12.6-day lag as accounts payable.

9 Q. How was the lag for the JOA calculated?

10 A. The JOA expenditures were lagged at 45 days, consistent
11 with the terms of the JOA. Under the JOA, there is a
12 45-day lag based on the payment terms included in the
13 agreement. The JOA states that payments are due 30
14 days after the month in which services were rendered.
15 The lag is measured from the mid-point of the month (30
16 days / 2 = 15) to the date of payment for services (30
17 days), totaling 45 days.

18 Q. Please describe the lag associated with uncollectible
19 accounts expense.

20 A. Uncollectible accounts expense was lagged at 43.6 days,
21 consistent with the revenue recovery lag, to reflect
22 the portion of revenue that is uncollectible.

23 Q. Please describe the lag associated with other O&M.

24 A. The lag on other O&M expenses was calculated to be 12.6
25 days. This calculation is based on an analysis of

ACCOUNTING PANEL

1 accounts payable payments made to vendors for materials
2 and services charged to O&M expense, excluding pension
3 and employee welfare expenses. Lag days were measured
4 from the invoice date to the payment date.

5 Q. Please describe the lead or lag associated with taxes
6 other than income taxes.

7 A. Individual studies were prepared to measure the lag
8 period for each type of tax paid by the Company for the
9 year 2007. The taxes related to corporate loans,
10 capital stock, and gross premium insurance are paid in
11 conjunction with the Company's federal tax return. The
12 lag assumes four annual payments (i.e., April 15, June
13 15, September 15 and December 15). We determined that
14 there was a lag of 36.5 days by calculating the number
15 of days that elapsed from the mid-point of the service
16 period (i.e., July 2) and the four payments,
17 respectively. Unemployment taxes have quarterly
18 payments on April 20, July 16, October 12 and January
19 31. There was an average of a 64-day lag that elapsed
20 from July 1, the mid-point of 2007, to each of the four
21 payment dates, respectively.

22 Q. Please describe the lag days associated with Federal
23 and state income taxes.

24 A. The Federal Income Tax ("FIT") and state income tax lag
25 assumes four annual payments (i.e., April 15th, June

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1 15th, September 15th and December 15th). We determined
2 that there was a lag of 36.5 days by the number of days
3 that elapsed from the mid-point of the service period
4 (i.e., July 2) and the four payments, respectively.

5 Q. Please describe the lag days associated with deferred
6 purchased power expense, materials and supplies,
7 amortization expense, deferred federal income taxes,
8 depreciation, and return on invested capital.

9 A. These components are assigned a zero lag to the amounts
10 included in the cost of service because they are non-
11 cash items.

12 Q. How did you calculate the Plant Materials and Stores
13 component of gas working capital?

14 A. We used the average balance for the historic year as a
15 proxy for the plant material and stores balances for
16 the ensuing twelve month period. The calculation is
17 shown on Exhibit G-3, Schedule 3, Page 2 of 3.

18 Q. How did you calculate the prepayments component of gas
19 working capital?

20 A. We used the same method as we used to calculate the
21 plant material and stores balances. The components of
22 prepayments and the balances used for the calculations
23 are shown on Exhibit G-3, Schedule 3, Page 3 of 3.

24 Q. Please describe Exhibit G-3, Schedule 4.

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1 A. The Company estimates that it will incur \$500,000 of
2 outside legal and consulting costs related to the
3 electric and gas rate filings. \$100,000 of these costs
4 were allocated to gas operations based on a net revenue
5 split. On Schedule 4, we calculated the after tax
6 amount to be \$58,500. We added this amount to the gas
7 rate base for the twelve months ending March 31, 2009.

8 Q. Did you calculate the deferred income taxes for the
9 twelve months ending March 31, 2009?

10 A. Yes. This calculation, shown on Exhibit G-3, Schedule
11 5, presents the difference between the balances of
12 accumulated deferred income taxes at March 31, 2008 and
13 March 31, 2009, respectively. The computation of this
14 change is shown on Exhibit G-4, Schedule 12, page 2 of
15 3.

16

Exhibit G-4, GAS COST OF SERVICE

17
18 Q. Please describe Exhibit G-4

19 A. Exhibit G-4 consists of a summary and twelve schedules
20 containing the historic and future gas cost of service.
21 The Accounting Panel supports all schedules with the
22 exception of Schedule 9, which is supported by Mr.
23 Hutcheson, and the forecast revenues for the twelve
24 months ending March 31, 2009, shown on Schedule 1 which
25 was provided to us by the Rate Panel. Page 1 of the

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1 Summary shows the historic and forecast cost of
2 service, page 2 of the Summary shows the calculation of
3 the revenue requirement, and page 3 of the Summary
4 lists all of the adjustments to the cost of service.

5 Q. How did you develop the historical and forecast cost of
6 service?

7 A. We began with the actual per books information for the
8 twelve months ended March 31, 2008. This information
9 is shown in Column 1 of Exhibit G-4, Summary, Page 1 of
10 3. Column 3 of the same exhibit sets forth the
11 adjustments necessary to bring historical revenues,
12 expenses, and rate base in line with the levels of
13 revenues, expenses and rate base projected for the
14 twelve months ending March 31, 2009.

15 Q. Please describe how the revenue requirement of \$424,900
16 shown on page 2 of the Summary was calculated?

17 A. We began with the projected March 31, 2009 rate base
18 from Exhibit G-3, Summary. To this balance we applied
19 the overall rate of return shown on Exhibit G-2,
20 Schedule 3. This produced a return of \$128,684. We
21 compared this number to the earned return projected on
22 page 1, column 4 of the Summary, which was a loss of
23 \$117,900. The difference between these two amounts was
24 \$246,584, which we factored up for customer

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1 uncollectible costs and income taxes to arrive at a
2 revenue requirement of \$424,900.

3 Q. Please describe Exhibit G-4, Schedule 1.

4 A. Exhibit G-4, Schedule 1 shows the increase in revenues
5 between the future and historic years reflecting
6 projected increases in the sale of gas and current
7 rates.

8 Q. Please describe the methodology used in developing the
9 Forecasted Gas Sales.

10 A. The forecast was based on the Company's budget for
11 calendar years 2008 and 2009 and utilized actual
12 recorded sales volumes for the twelve months ended
13 September 30, 2007 as its starting point. These sales
14 volumes were adjusted to neutralize deviations in sales
15 due to warmer or colder weather during the base year.
16 The base year sales were further adjusted to reflect
17 the annualization of sales from new business customers
18 attached during the base year as well as incremental
19 sales for new business additions during the forecast
20 period. The actual sales for the twelve months ended
21 March 2008 and the forecasted sales for the twelve
22 months ended March 2009 are on Exhibit G-6, Schedules 1
23 and 2, respectively. The actual revenues for the twelve
24 months ended March 2008 and the forecasted revenues for
25 the twelve months ended March 2009, as discussed in the

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1 Rate Panel direct testimony are on Exhibit G-6,
2 Schedules 3 and 4, respectively.

3 Q. Do you periodically review and/or update the gas sales
4 forecast?

5 A. Yes, the forecast is typically reviewed and updated
6 annually each summer. The forecast update will be
7 completed during the later part of August. The
8 preliminary indications are that a downward adjustment
9 in sales volume will be required. Such an adjustment
10 will be included in the update in this case.

11 Q. Please describe the Weather Normalization Adjustment.

12 A. The Weather Normalization Adjustment recognizes that
13 the twelve months ended September 30, 2007 were warmer
14 than normal. Measured on a Heating Degree Day basis,
15 the year was 3.4% warmer than normal. The impact was
16 calculated monthly by service classification by
17 multiplying the variation between normal and actual
18 heating degree days by a "use per heating degree-day
19 per average customer factor", determined by regression
20 analysis, times the actual number of customers.

21 Q. Please define normal weather.

22 A. Normal weather is defined as the average weather
23 condition over the 30 years from 1977 through 2006. A
24 30-year average condition is used by the National
25 Weather Service to define normal weather.

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1 Q. Please describe Exhibit G-4, Schedule 2.

2 A. Exhibit G-4, Schedule 2 shows the increase in gas cost
3 recoveries between the future and historic years
4 reflecting projected increases in the sale of gas and
5 the current base cost of gas.

6 Q. Please describe how you calculated Adjustment No. (3a),
7 Changes in Operation and Maintenance Expenses to
8 Reflect Increases In Wages and Salaries, and Adjustment
9 No. (3b), Changes in Operation and Maintenance Expense
10 to reflect Increase in Additional Employee Positions,
11 which are shown on Exhibit G-4, Summary, as well as on
12 Exhibit G-4, Schedule 3, pages 1 and 2.

13 A. In developing the increase in wages and salaries that
14 is applicable to Pike gas operations, which amounts to
15 \$12,800 (\$10,500 of which is detailed on Exhibit G-4,
16 Schedule 3, Page 1 of 2, and \$2,300 of which is
17 detailed on Exhibit G-4, Schedule 3, Page 2 of 2), we
18 first analyzed the actual, historic labor cost of the
19 consolidated O&R system for the twelve months ended
20 March 31, 2008. We then made an adjustment to the
21 actual, per-books consolidated labor expense of a
22 reduction of \$523,000 to correct an erroneous
23 accounting entry that was discovered during the
24 analysis.

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1 The actual, per books consolidated labor data was
2 further adjusted for certain normalizing entries. The
3 purpose of the normalizing entries was to annualize the
4 labor expense for certain new employee positions that
5 were added during the test year and, therefore, the
6 historic test year labor expense did not reflect a full
7 year of cost for such employees. The normalizing
8 adjustments amounted to \$288,966 of additional expense
9 for new union positions and \$29,167 of additional
10 expense for new management positions. Details
11 regarding those positions are as follows:

12 Weekly (i.e., Union) Positions - Electric Overhead

13 Linemen, ten new positions added during September 2007,
14 normalized to add five months of labor costs to the
15 historic test year; Electric Underground Linemen, six
16 new positions added during June 2007, normalized to add
17 two months of labor costs to the historic test year.

18 Semi-Monthly (i.e., Management) Positions - Electric

19 Underground Line Supervisor, one new position added
20 during June 2007, normalized to add two months of labor
21 costs to the historic test year; Emergency Preparedness
22 Specialist, one new position, added during June 2007,
23 normalized to add two months of labor cost to the
24 historic test year.

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1 Q. Did you include any other adjustments for additional
2 employee positions in your analysis?

3 A. Yes. The analysis includes a total of twenty-one
4 additional employee positions, six of which are union
5 positions and fifteen of which are management
6 positions. Twenty of these positions were included in
7 a new rate plan (NYPSC Case 07-E-0949) that went into
8 effect July 1, 2008 for Orange and Rockland's New York
9 electric operations subject to final approval by New
10 York Public Service Commission ("NYPSC"). The Final
11 Rate Order by the NYPSC is expected during July 2008.
12 Also, one union position was included that was not part
13 of the above-referenced O&R proceeding -- the addition
14 of a Customer Service Representative as a result of the
15 establishment of new customer service center in the
16 Pike service territory. Details regarding the
17 additional employee positions, including the assumed
18 date filled and whether the cost of the position is
19 allocated to Pike electric and/or gas O&M expense is
20 shown is Schedule 3 of Exhibit G-4 As indicated on
21 Schedule 3, seven positions out of the total twenty-one
22 positions have costs allocated to Pike gas operations.
23 The analysis then separately identified the adjusted
24 and normalized consolidated labor costs as to total
25 wages applicable to union employees and total wages

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1 applicable to management employees. It also identified
2 the amount of adjusted wages that was charged to Pike
3 gas O&M expense, which amounted to 0.14% of the
4 adjusted (as described above) total consolidated wages
5 of O&R for the twelve months ended March 31, 2008.
6 Then, using the actual and budgeted wage increase
7 percentages applicable to union and management
8 employees, we calculated the amount of total wages that
9 represent base pay versus wage increase amounts for the
10 period from April 1, 2008 through March 31, 2010. The
11 wage increase percentages for union employees are
12 pursuant to the negotiated labor agreement with Local
13 503 of the International Brotherhood of Electrical
14 Workers, which became effective on June 1, 2004 and
15 extends through June 1, 2009. The agreement provides,
16 among other things, for a wage increase of 3.25%, which
17 became effective on June 1, 2007, and 3.50%, which
18 became effective on June 1, 2008. The 3.50% negotiated
19 wage increase was then applied to the period through
20 March 31, 2010 in the calculations. The wage increase
21 applicable to management employees was 3.25% effective
22 April 1, 2007 and 3.50% effective April 1, 2008 and
23 April 1, 2009, respectively. We then calculated the
24 forecasted increase in wages using these percentages.

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1 Once the total wage increase amount was calculated for
2 union and management employees, the portion of such
3 wage increase that is applicable to Pike gas operations
4 was calculated. For those employees who were part of
5 the historic test period in this case (excluding the
6 additional employees) the amount allocated to Pike gas
7 operations was 0.14%, which, as described above, is the
8 historic percent of consolidated O&R wages that was
9 allocated to Pike gas operations for the twelve months
10 ended March 31, 2008. For the 21 additional employees
11 the actual projected amounts of wages to be charged to
12 Pike gas operations, based on each particular position
13 and salary level, was calculated individually.

14 Q. Please continue with a description of Adjustment No.
15 (4a), Changes in Operation and Maintenance Expense to
16 Reflect the Estimated Increase in Payroll Ancillary
17 Costs and Adjustment No. (10), Changes in Taxes Other
18 Than Income Taxes to Reflect Increases in Payroll
19 Taxes, as shown on Exhibit G-4, Summary, as well as on
20 Exhibit G-4, Schedule 4 and Schedule 10.

21 A. The estimated increase in payroll ancillary costs,
22 which amounts to \$2,100, was calculated by applying the
23 fringe benefit rate of 16.36% to the forecasted wage
24 increase amount for management and union employees,
25 which was developed on Exhibit G-4, Schedule 3(a) and

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1 3(b), and which was described earlier in this
2 testimony. The 16.36% fringe benefit rate includes the
3 cost of employee health and life insurance at 11.95%,
4 Workers' Compensation insurance at 2.38%, and the cost
5 of O&R's 401K matching contribution of 2.03%. These
6 rates were developed based on the forecasted cost of
7 each benefit item in relation to the total forecasted
8 labor costs of the O&R system for the year 2008. The
9 estimated increase in Payroll Taxes, which amounts to
10 \$1,000, was calculated by applying the payroll tax rate
11 of 7.74% to the forecasted wage increase amount for
12 management and union employees. The 7.74% payroll tax
13 rate includes the cost of Federal Insurance
14 Contribution Act ("FICA") Tax at 6.20%, Medicare at
15 1.45%, Federal Unemployment Tax at 0.07%, and State
16 Unemployment Taxes at 0.02%. These tax rates were
17 developed based the estimated O&R consolidated costs
18 for the year 2008 in the same manner as described above
19 for the payroll ancillary costs.

20 Q. Please describe Adjustment No. (4b), Changes in
21 Operation and Maintenance Expenses to Reflect Increases
22 in Pension Benefit Expense, as shown in Exhibit G-4,
23 Schedule 4, Page 2.

24 A. Adjustment No. (4b) for \$6,300 reflects the \$3,600
25 increase in SFAS 87 pension expense net of

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1 capitalization and recoveries as compared to the actual
2 pension expense for the twelve months ended March 31,
3 2008 and the \$2,700 increase in SFAS 106 OPEB expense
4 net of capitalization and recoveries and VEBA health
5 insurance reimbursements as compared to the actual OPEB
6 expense for the twelve months ended March 31, 2008.

7 The Company's actuary, Buck Consultants, calculated the
8 SFAS 87 pension and SFAS 106 other post employment
9 benefit expense.

10 Q. Please describe Adjustment No. (5), Changes in
11 Operation and Maintenance Expenses to Reflect Rent of
12 the Milford Office, as shown in Exhibit G-4, Schedule
13 5.

14 A. Adjustment No. (5) for \$4,400 reflects the 12.59%
15 allocation to gas of the \$35,000 annual rent of the
16 Milford Office opened in April 2008.

17 Q. Please describe Adjustment No. (6), Changes in
18 Operation and Maintenance Expense to Reflect
19 Amortization of Estimated Outside Rate Case Expenses,
20 as shown on Exhibit G-4, Summary, as well as on Exhibit
21 G-4, Schedule 6.

22 A. Adjustment No. (6) results in an increase in O&M
23 expense of \$12,500 for the effect of the forecasted
24 annual amortization of costs incurred in the
25 preparation and filing of this gas base rate case. In

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1 Schedule 6, Pike allocated 20% of its estimated
2 incremental rate case cost of \$500,000 or \$100,000 to
3 gas operations. When combined with the forecasted
4 unrecovered balance of prior rate case costs of
5 \$12,500, this results in a balance to be amortized of
6 \$112,500. Assuming a five-year amortization period,
7 this results in an annual amortization allowance of
8 \$22,500, which is \$12,500 higher than the currently
9 allowed rate case cost amortization of \$10,000.

10 Q. Please describe Adjustment No. (7), True-up of Joint
11 Use Operating Expense, as shown on Exhibit G-4,
12 Summary, as well as on Exhibit G-4, Schedule 7.

13 A. The adjustment to reflect current Joint Use Rents
14 decreases O&M expense by \$690 (rounded up on the
15 Exhibit to \$700). The adjustment was calculated by
16 comparing the amount of JOA expense that was actually
17 charged to Pike gas operations during the twelve months
18 ended March 31, 2008, which amounted to \$43,914, to the
19 revised and updated annual billing amount of \$43,224.
20 The billing amount under the JOA is updated annually
21 based on the actual charges experienced by O&R during
22 the preceding year. In this case, the new billing
23 amount reflects an update to the year 2006 data, and
24 the new monthly billing rate will remain in effect

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1 until mid-2008, at which time it will be updated to
2 reflect actual charges experienced by O&R during 2007.

3 Q. Please address Adjustment No.(8).

4 A. Adjustment No.(8) was made to synchronize Pike's
5 actual customer uncollectible write-off experience
6 during the twelve months ended March 31, 2008 with its
7 forecast revenues for the twelve months ending March
8 31, 2009. It was calculated as the average of bad debt
9 write-offs as a percentage of revenues. The resultant
10 factor of 0.8133 is then applied to the forecasted
11 revenues for the rate year. The result of \$15,900 is
12 compared to the bad debt expense accrued during the
13 test year of \$13,700, for an increase of \$2,200.

14 Q. Mr. Hutcheson states on page 10 of his direct testimony
15 that the Accounting Panel will set forth a proposal to
16 amortize the \$36,000 by which the computed reserve
17 based on proposed rates exceeds the actual reserve.
18 What is your proposal?

19 A. Yes, we propose to recover the depreciation reserve
20 deficiency over the average remaining life for gas
21 plant assets of 40 years. This amounts to \$900 a year
22 as shown on Exhibit G-4, Schedule 9, Page 3.

23 Q. Please describe Adjustment No. (11), Changes in Gain on
24 Sale of Utility Plant to reflect the amortization of

ACCOUNTING PANEL

1 the net gain from the sale of the Milford Office, as
2 shown in Exhibit G-4, Schedule 11.

3 A. The gas allocation of the gain on the sale for the 50%
4 of the Milford Office property designated as utility
5 plant is \$27,625. The balance to be amortized at March
6 31, 2009 is \$21,027. The annual amortization based on a
7 five-year amortization period is \$1,320. The
8 amortization included in the test year is (\$5,607) for
9 a net adjustment of (\$4,300).

10 Q. Please describe Adjustment No. (12), Calculation of
11 Income Tax Expense for the Twelve Months Ending March
12 31, 2009, as shown Exhibit G-4, Schedule 12.

13 A. Adjustment No. (12) shows the necessary additions and
14 subtractions that must be made to operating income
15 before taxes in order to determine taxable income to
16 which the statutory tax rates are applied.

17 Q. Please explain page 3 of Schedule 12.

18 A. Page 3 of Schedule 12 shows the calculation of the
19 interest deduction included in page 1 of Schedule 12.
20 The majority of long term debt has been issued by
21 Orange and Rockland for itself and its subsidiary
22 utility affiliates, Pike and Rockland Electric Company.
23 This adjustment is necessary in order to allocate the
24 proper level of interest expense to each jurisdiction,

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1 based on Orange and Rockland's overall consolidated
2 interest expense.

3

4 **Exhibit G-5, THREE-YEAR RATE PLAN**

5 Q. Is the Company sponsoring a three-year rate plan
6 proposal as an alternative to a one-year case?

7 A. Yes.

8 Q. Please explain how a rate plan of this length would
9 benefit the Company's customers.

10 A. Multi-year rate plans provide the Company with greater
11 flexibility to schedule and execute critical programs
12 in the most cost-effective manner. They also place a
13 greater responsibility on the Company to manage its
14 resources over several years when there may be larger
15 swings in economic conditions and permit greater focus
16 on operating efficiencies as opposed to the alternative
17 of a relatively constant focus on rate litigation.
18 When the Company manages its resources in a cost-
19 effective manner, both the Company and its customers
20 benefit. That is, the Company could receive a benefit
21 during a portion of the current rate period, and its
22 customers during all successive rate periods, retaining
23 the more significant value of the improvements in the
24 business.

25 A three-year rate plan balances the impact of future

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1 uncertainties on customers and the Company.

2 Q. Please explain how your multi-year proposal would work.

3 A. The Company proposes that the rates set for the first
4 rate year become the base from which projections are
5 made for the second and third years of the rate plan.
6 The Company further proposes that the Commission adopt
7 a series of staged rate changes for the second and
8 third years. We would like to emphasize that, by
9 proposing a three-year plan in the alternative, the
10 Company does not waive its rights to file for new rates
11 immediately following the conclusion of this case, if
12 the Company views (1) the rate change granted by the
13 Commission for the first year to be inadequate, or (2)
14 the terms for an additional rate year(s) under a multi-
15 year rate plan to be unreasonable. We would also note
16 that the various five-year amortizations proposed
17 throughout the Company's filing are proposed for both
18 the one-year rate request and the three-year rate
19 proposal.

20 Q. Does Exhibit G-5 show the calculation of the Company's
21 revenue requirement for the second and third years?

22 A. Yes, it does.

23 Q. Please describe Exhibit G-5.

24 A. Exhibit G-5 consists of a summary and thirteen
25 schedules containing Pike's proposal for a multi-year

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1 rate plan. The proposal, if adopted by the Commission,
2 would establish rate increases for three years and
3 offer the Commission the option to phase-in the rate
4 increases on a levelized and earnings neutral basis,
5 through the use of deferred accounting. The phasing-in
6 of requested rate increase would reduce the customer
7 bill impact in the first year rate year and allow
8 customers certainty as to their base rates for the next
9 three years.

10 Q. What are the annual and levelized rate increases the
11 Company is proposing in the rate plan?

12 A. As indicated previously and shown on Exhibit G-5,
13 Summary, Page 5 of 7, the rate increase for the first
14 rate period would be \$424,900. For the second and
15 third periods the corresponding rate increases would be
16 \$19,800 and \$16,400, respectively. Exhibit G-5,
17 Summary, Page 4 of 7, shows the calculation of a
18 levelized annual increase amounting to \$223,900 per
19 year.

20 Q. Please explain how you derived the rate increases for
21 the second and third rate years.

22 A. As shown on Exhibit G-5, Schedules 1 through 14, the
23 Company assumed and reflected an increase in its
24 estimate of gas sales and base revenues by 1 percent or
25 \$7,800 each year (Schedule 1), salary and wage

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1 increases of 3.5 percent per year or \$10,900 and
2 \$11,200 respectively for the second and third
3 years(Schedule 2), increases in the cost of employee
4 benefits of \$7,500 and \$7,700 respectively for the
5 second and third years (Schedule 3), general
6 inflationary increases on other operating expense of
7 2.3 percent per annum or \$3,200 and \$3,300 respectively
8 for the second and third years (Schedule 4),
9 uncollectible costs related to the higher revenues of
10 \$100 in each year (Schedule 5), depreciation
11 associated with new plant additions of \$700 in each
12 year (Schedule 6) and net increases in payroll taxes
13 related to higher salaries and wages of \$800 in each
14 year (Schedule 7). The associated computation of
15 Federal and state income taxes is shown on Schedule 8.
16 Page 5 of Schedule 8 shows the calculation of the
17 interest deduction included in pages 1 and 3 of
18 Schedule 8. The majority of long term debt has been
19 issued by Orange and Rockland for itself and its
20 subsidiary utility affiliates, Pike and Rockland
21 Electric Company. This adjustment is necessary in
22 order to allocate the proper level of interest expense
23 to each jurisdiction.

24 Q. Please discuss how rate base was projected for the
25 second and third years of the proposed rate plan.

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- 1 A. Rate base is shown on Exhibit G-5, Summary, Page 6 and
2 reflects the Company's forecast of plant additions,
3 depreciation accruals, working capital, and changes in
4 deferred income tax balances. In addition, deferred
5 balances have been adjusted to reflect the impact of
6 amounts amortized each year. The details supporting the
7 adjustments to rate base are shown on Schedules 9
8 through 13.
- 9 Q. Does that conclude your testimony?
- 10 A. Yes, it does.

PIKE COUNTY LIGHT & POWER COMPANY
DIRECT TESTIMONY OF
RICHARD DILORETO

1 Q. Please state your name and business address.

2 A. My name is Richard S. DiLoreto and my business address is One Blue Hill Plaza,
3 Pearl River, New York 10965.

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

5 A. I am employed by Orange and Rockland Utilities, Inc. (“Orange and Rockland”),
6 the corporate parent of Pike County Light & Power Company (“Pike” or the
7 “Company”) as Director, Gas Technical Services. In this position I am
8 responsible for the Gas Engineering, Contract Administration and Gas Control
9 Center Departments.

10 Q. Please provide your educational background and professional experience.

11 A. In 1989, I graduated from Pace University with a Bachelor of Business
12 Administration Degree in Management. In 1993, I graduated from Pace
13 University with an MBA Degree in Finance. I attended a Gas Distribution
14 Engineering course at the Illinois Institute of Technology in 1988 and a Strategic
15 Leadership course at Penn State in 1995. I joined Consolidated Edison Company
16 of New York, Inc. (“Con Edison”) in February 1972 as an apprentice in the Gas
17 Operations Department in the Bronx. In 1982 I was promoted to 1st line
18 supervisor in Bronx Gas Operations. I held a series of positions of increasing
19 responsibility there until 1989 when I became the Manager of the Gas Quality
20 Assurance Department. In 1991, I became a Manager in Central Gas
21 Engineering. In 1992, I became the Section Manager of the Corrosion Control

PIKE COUNTY LIGHT & POWER COMPANY
DIRECT TESTIMONY OF
RICHARD DILORETO

1 Department in Central Gas Operations. In 1994, I became the Manager of the
2 Liquefied Natural Gas (LNG) Plant. In 1996, I became the Section Manager of
3 the Gas Meter Shop. In 1997, I became the Section Manager of Gas Distribution
4 Services in Westchester Gas Operations. In 1999, I became Section Manager of
5 Gas Distribution Services in Manhattan Gas Operations. In 2001, I became the
6 Department Manager of the Gas Emergency Response Center for Gas Operations.
7 In 2008, I assumed my present position of Director of Gas Technical Services at
8 Orange and Rockland.

9 Q. Have you previously sponsored testimony before the Pennsylvania Public Utility
10 Commission?

11 A. No, I have not.

12 Q. What is the purpose of your testimony?

13 A. The purpose is to provide an overview of Pike's gas system that serves the
14 Matamoras, Pennsylvania area and discuss the Company's planned plant
15 additions and construction plans in Matamoras. In addition, I will describe Pike's
16 valve installation project and gas main replacement program.

17 Q. Please provide an overview of Pike's gas system that serves the Matamoras,
18 Pennsylvania area.

19 A. Pike serves over 1,200 residential and commercial gas customers in the
20 Matamoras area. The system consists of 20 miles of high and low pressure
21 distribution main ranging in size from 2" through 8". The system is radially fed

PIKE COUNTY LIGHT & POWER COMPANY
DIRECT TESTIMONY OF
RICHARD DILORETO

1 from Port Jervis, New York via a 6" cathodically protected high-pressure (i.e., 60
2 psig maximum allowable operating pressure) gas main. The low-pressure system
3 is subsequently fed by three pressure regulator stations from the high pressure
4 system. The pressure regulator stations are located at Avenue K & Delaware
5 Avenue, Avenue I & Third Street, and Avenue K & Tenth Street, respectively.
6 The high pressure system consists of approximately six miles of plastic and
7 cathodically protected and wrapped steel high pressure gas main. The low
8 pressure system consists of 14 miles of steel, one mile of plastic, and seven miles
9 of cast iron pipe. Cast iron pipe is the oldest pipe in the system. Pike's customers
10 are served by 1004 gas services ranging in size from ½" to 2". Of that total, 329
11 are plastic and the remaining services are steel. Required maintenance on the
12 system has been relatively low with the major operational and safety concerns
13 being cast iron main breaks, corrosion, and water infiltration into the low-pressure
14 system.

15 Q. Please describe the major plant expenditures that Pike plans to complete during
16 the twelve month period ending June 30, 2009 and the reason for such additions.

17 A. By the third quarter of 2008, Pike plans to complete a valve installation program,
18 which began in 2005, on the low-pressure system in Matamoras. Thus far, Pike
19 has installed 20 valves, with the locations of these valves plotted on the attached
20 map (Exhibit G -3, Schedule 7). The work will be performed by a contractor
21 pursuant to an existing blanket contract which contains established unit prices.

PIKE COUNTY LIGHT & POWER COMPANY
DIRECT TESTIMONY OF
RICHARD DILORETO

1 Q. What is the purpose of this valve installation project?

2 A. This project will allow Pike to sectionalize the low pressure gas system in
3 Matamoras, which has had a history of flooding by the Delaware River. Twenty
4 valves were installed in 2005 and 2006 which divided the system into three gas
5 control areas that allow us to isolate only those areas requiring shut down rather
6 than the entire low-pressure system. The installation of two additional valves this
7 year will provide for a fourth gas control area. Completion of this project will
8 allow Pike to quickly and systematically isolate the low pressure system in blocks
9 of less than 250 customers, in the event of a flood or other event. The installation
10 of these valves continues Pike's efforts to enhance the reliability and safety of the
11 low-pressure gas distribution system serving the Matamoras area.

12 Q. What is the projected cost of this valve installation project?

13 A. It is estimated that the cost to purchase and install the two valves is approximately
14 \$30,000, as set forth in the estimate set forth in Exhibit G -3, Schedule 6.
15 Unknown subsurface structures, pipe conditions or permit stipulations could
16 result in a higher final cost.

17 Q. When will the valve installation project be completed?

18 A. This project is scheduled to be completed in the third quarter of 2008.

19 Q. Does Pike plan to implement any other gas system improvements?

20 A. Yes. Starting in the second half of 2008, Pike will initiate a long-term
21 replacement program for the low-pressure cast iron main, the unprotected steel

PIKE COUNTY LIGHT & POWER COMPANY
DIRECT TESTIMONY OF
RICHARD DILORETO

1 main, and the unprotected steel services connected to those sections. All will be
2 replaced by plastic pipe and reconnected to the high pressure system. On June
3 25, 2008, the Federal Register published, "*Integrity Management Program for*
4 *Gas Distribution Pipelines*" on June 25, 2008 ("Proposed Regulation"). The
5 final regulation is expected to be issued by the end of 2008. Operators will be
6 required to prepare a written integrity management plan and implement the plan
7 within 18 months after the final rule is enacted. Early indications are that the
8 Proposed Regulation will have a significant impact on gas distribution companies,
9 including Pike. Pike's proposed main replacement program will address certain
10 requirements set forth in the Proposed Regulation. The rule will require all gas
11 distribution companies to examine their infrastructure to identify threats to the
12 pipelines and determine and implement actions to manage the threats. One
13 primary threat that all gas distribution companies face is leakage and corrosion.
14 A method for managing this threat is through the replacement of old and/or
15 leaking main such as cast iron and unprotected steel. Pike's replacement program
16 will focus on extending its high-pressure system that runs predominantly down
17 Avenues H and I, east on 10th Street and systematically replacing the cast iron and
18 bare steel with an emphasis on the flood prone areas. The six miles of our cast
19 iron main are 8" diameter or less with four miles being 4" or less. Small diameter
20 cast iron main, 8" and less, is brittle and subject to cracking. As the cast iron
21 main is replaced, the risk of cast iron main leaks and water infiltration into the

PIKE COUNTY LIGHT & POWER COMPANY
DIRECT TESTIMONY OF
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1 low pressure system is further reduced. Pike's six miles of unprotected steel
2 presents risks as well. Unprotected steel is subject to corrosion and while the
3 leaks tend to be less severe than cast iron cracks, the deterioration of the steel
4 worsens over time and the main is prone to water infiltration. The main
5 replacement would include service renewals and service regulator installations.
6 In 2008, Pike will install 400 feet of 4" plastic main on 10th Street, tie it in to the
7 high pressure system, and transfer adjacent low pressure services to the new high
8 pressure gas main. In the first quarter of 2009, Pike will install an additional 600
9 feet of 4" plastic main to the end of 10th Street, tie it into the new high pressure
10 main, and transfer adjacent services to the new high pressure gas main. After
11 completion of the high pressure main on 10th Street, the cast iron and unprotected
12 steel mains and services in and around that area will systematically begin to be
13 replaced and converted to high pressure plastic.

14 Q. What is the annual cost of the replacement program?

15 A. The annual cost of the replacement program is \$70,000, as set forth in Exhibit G -
16 3, Schedule 6.

17 Q. What is included in the category of Blankets set forth in Exhibit G-3, Schedule 6?

18 A. Blankets include a variety of work, including all materials and labor, which must
19 be performed regularly so that the Company may continue to provide safe and
20 reliable service. Blankets are an accounting convention, long employed by the
21 Company whereby, for the sake of convenience, the costs of certain recurring

PIKE COUNTY LIGHT & POWER COMPANY
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- 1 labor and equipment are grouped together. Included in the overall blankets
2 category on Exhibit G-3, Schedule 6 -- are the Gas Distribution Blankets. The
3 Company uses these blankets to support its gas distribution business, and they
4 break down to the following sub-categories: New Business, Gas Main
5 Replacements and Regulator Installations. These are relatively self-explanatory,
6 and cover routine expenditures on the Gas Distribution system to connect new
7 customers, address municipal requirements, and provide necessary funds for daily
8 requirements and upkeep of the distribution system. Also included in the overall
9 blankets category are the costs of tools, meters, and test equipment.
- 10 Q. Does that conclude your testimony?
- 11 A. Yes it does.

PIKE COUNTY LIGHT & POWER COMPANY
DIRECT TESTIMONY OF
CHARLES D. HUTCHESON - GAS

1 Q. Please state your name and business address.

2 A. My name is Charles D. Hutcheson. My business address
3 is 4 Irving Place, New York, New York.

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

5 A. I am an employee of Consolidated Edison Company of New
6 York, Inc. ("CECONY") and hold the position of Manager
7 of the Property Tax and Depreciation group. My duties
8 include responsibility for the property tax and
9 depreciation functions for the regulated subsidiaries
10 of Consolidated Edison, Inc., which includes Pike
11 County Light & Power Company ("the Company").

12 Q. Please briefly outline your educational background and
13 business experience.

14 A. I graduated from Hofstra University in May 1978 with
15 the degree of Bachelor of Business Administration in
16 Accounting. I have been employed by CECONY since
17 January 2, 1979 and have held various positions of
18 increasing responsibility within the Finance
19 Department. My first assignment with CECONY was in the
20 Depreciation Section. I spent my first 15 years of
21 employment in that area rising to the position of
22 Senior Accountant. In 1993, I moved to the Rates and

CHARLES D. HUTCHESON - GAS

1 Budget Section. In 1996, I transferred to the
2 Financial Restructuring Team, where my duties were to
3 assist on the development of CECONY's rate plan in the
4 New York Public Service Commission's Competitive
5 Opportunities Proceeding. I moved to the Tax
6 Department in 1997 after the Restructuring Team
7 disbanded to work as a Senior Tax Accountant in the
8 Federal Tax Section. In September 1999, I was promoted
9 to Manager, Property Taxes. In December 2001, I once
10 again began working on depreciation matters when the
11 Tax Department assumed responsibility for the book
12 depreciation function for our regulated subsidiaries,
13 including the Company. My duties include
14 responsibility for gathering the statistical data for
15 and preparing plant mortality and net salvage studies
16 and for analyzing and interpreting the results of these
17 studies.

18 Q. Are you a member of any professional societies?

19 A. Yes. I am a member of the Society of Depreciation
20 Professionals. The group was formed to recognize the
21 field of depreciation and those individuals
22 contributing to the field. It also promotes the
23 professional development of those practicing in the

1 field of depreciation and serves as a forum to collect
2 and exchange information and ideas related to
3 depreciation. Membership is not restricted to the
4 utility industry as the Society is represented by those
5 in the fields of government, education, and industry.

6 Q. Have you previously testified before any regulatory
7 commission?

8 A. I have submitted testimony and testified on the subject
9 of depreciation and/or property taxes for CECONY and
10 Orange and Rockland Utilities, Inc. before the New York
11 State Public Service Commission and before the New
12 Jersey Board of Public Utilities (on behalf of Rockland
13 Electric Company) in numerous cases.

14 Q. What is the purpose of your testimony in this
15 proceeding?

16 A. The purpose of my testimony is to present
17 recommendations with respect to the annual book
18 depreciation rates for the Company's Gas Utility Plant.
19 In addition, I will identify the Accumulated Provision
20 for Depreciation per Books at December 31, 2007, the
21 computed reserve based on existing rates, and the
22 computed reserve based on proposed rates for Gas Plant.
23 Lastly, my testimony will detail the variations between

1 the book and theoretical reserve.

2 Q. Have you reviewed the adequacy of the Accumulated
3 Provision for Depreciation per books and the factors
4 that determine annual depreciation expense?

5 A. Yes, I have. The Company prepares annual studies of
6 depreciation that test the Accumulated Provision for
7 Depreciation per Books. In addition, the Company
8 prepares plant mortality studies to determine average
9 service lives and life tables that are appropriate for
10 each depreciable asset account or sub-account. The most
11 recent studies are based on plant mortality experience
12 through December 31, 2006.

13 Q. Based on these studies, are you recommending any
14 changes to depreciation related to the Company's Gas
15 Utility Plant?

16 A. Yes, after a thorough review of the aforementioned
17 annual studies of depreciation, I have concluded that
18 various changes to the Company's depreciation
19 parameters are required.

20 Q. Have you prepared an exhibit for this proceeding that
21 summarizes your proposals?

22 A. Yes. I have prepared an exhibit entitled "PIKE COUNTY
23 LIGHT AND POWER COMPANY, PROPOSED DEPRECIATION RATE

CHARLES D. HUTCHESON - GAS

1 CHANGES FOR GAS PLANT AT DECEMBER 31, 2007."

2 Q. Was this exhibit prepared under your direction and
3 supervision?

4 A. Yes, it was.

5 MARK FOR IDENTIFICATION AS EXHIBIT ____ (G-10,
6 Schedule 1)

7 Q. Please describe this exhibit.

8 A. The exhibit compares the Annual Provision for
9 Depreciation on a "BOOK BASIS" and on a "PROPOSED
10 BASIS". This exhibit also includes a comparison of the
11 Accumulated Provision for Depreciation per books at
12 December 31, 2007 to a computed, or theoretical reserve
13 based on depreciation parameters currently in effect,
14 and on the average service lives and life tables that I
15 am proposing in this case.

16 Q. What is the basis for the changes you have proposed?

17 A. The proposed changes are based primarily on my review
18 and analysis of the historical data comprising the
19 Company's plant mortality studies. The studies are my
20 primary means of determining an appropriate average
21 service life and h-curve by employing actuarial methods
22 based on past experience. The data within those
23 studies are organized into various groupings, referred

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1 to as rolling or shrinking bands, which aid in the
2 analysis of the extensive historical information
3 available. In those instances where an account does
4 not have sufficient retirement results to produce
5 statistically reliable mortality data, I relied on
6 existing depreciation parameters.

7 Q. What part does the average service life play in the
8 determination of depreciation rates?

9 A. The estimated average service life is used to provide
10 for the recovery of the original cost of plant over its
11 useful life.

12 Q. Please describe the changes you propose to the average
13 service lives as a result of the aforementioned
14 depreciation studies.

15 A. As set forth in my Exhibit ____ (G-10, Schedule 1), I
16 propose to implement six changes to average service
17 lives that will result in an increase in annual
18 depreciation expense of \$597 based on the book cost of
19 plant at December 31, 2007.

20 Q. What is the effect on annual depreciation expense of a
21 change to an average service life?

22 A. The depreciation expense accrual varies inversely with
23 its underlying average service life - the longer the

1 service life, the lower the annual depreciation rate,
2 and therefore, the lower annual depreciation expense.
3 Conversely, a shorter service life results in a higher
4 annual depreciation rate, and therefore, a higher
5 annual depreciation expense. My proposals result in
6 changes that both increase and decrease lives that
7 result in a relatively minor change in the overall
8 level of depreciation expense. In addition, as I
9 discuss below in my testimony, the Company is
10 experiencing a depreciation reserve variation. In
11 their direct testimony, the Company's Accounting Panel
12 proposes how to address this situation.

13 Q. Please describe the changes you propose to the life
14 tables as a result of your study?

15 A. Life tables, or "h-curves" are survivor curves that
16 represent typical patterns of retirement dispersion.
17 An h-curve, along with an average service life is used
18 to compute a theoretical reserve for depreciation.
19 Changes to h-curves do not impact annual depreciation
20 expense but do affect computed reserves, which are used
21 to help determine whether the Company's actual book
22 depreciation reserve is adequate.

23 Q. Do you have an exhibit containing the data you relied

CHARLES D. HUTCHESON - GAS

1 on to select appropriate depreciation rates?

2 A. Yes, I do. For accounts where I have performed studies,
3 I have an exhibit entitled "PIKE COUNTY LIGHT AND POWER
4 COMPANY, GAS UTILITY PLANT, SUMMARY OF AVERAGE SERVICE
5 LIVES, EQUIVALENT "h" CURVES AND OTHER STATISTICAL DATA
6 INDICATED BY PLANT MORTALITY STUDIES BASED ON
7 EXPERIENCE THROUGH DECEMBER 31, 2006."

8 Q. Was this exhibit prepared under your direction and
9 supervision?

10 A. Yes, it was.

11 MARK FOR IDENTIFICATION AS EXHIBIT ____ (G-10,
12 Schedule 2)

13 Q. Please describe this exhibit.

14 A. The exhibit includes computer generated average service
15 lives, equivalent h-curves, and other statistical data
16 indicated by the rolling and shrinking band analysis of
17 the Company's mortality experience with respect to Gas
18 Utility Plant from 1952 (or the earliest available
19 date), through 2006.

20 Q. From what source was the data for this exhibit
21 obtained?

22 A. The Company utilizes a program adopted from the New
23 York State Public Service Commission's computer

CHARLES D. HUTCHESON - GAS

1 programs that employ actuarial methods for the
2 development of life tables and average service lives
3 based on utility plant mortality experience.

4 Q. What is the source of the data for the aforementioned
5 programs?

6 A. The source data comes from the Company's books and
7 records.

8 Q. What part does salvage play in the determination of
9 depreciation rates?

10 A. In lieu of recovering net salvage costs through the
11 annual depreciation rate, the Pennsylvania Public
12 Utility Commission establishes an annual allowance to
13 be collected through base rates which is computed by
14 averaging the Company's annual actual expenditures for
15 net salvage costs. That amount is then added to or
16 subtracted from annual depreciation expense. The
17 Company's Accounting Panel addresses the adjustment for
18 net salvage in their testimony.

19 Q. Please review your findings on the difference between
20 the book and computed reserve for depreciation.

21 A. Exhibit ____ (G-10, Schedule 1) shows that for the total
22 Gas Utility Plant at December 31, 2007, the Accumulated
23 Provision for Depreciation per books amounted to

CHARLES D. HUTCHESON - GAS

1 approximately \$354,000. The computed reserve
2 summarized under the heading "BOOK BASIS" was
3 calculated on the basis of the average service lives
4 and life tables currently in use by the Company and in
5 total amounted to approximately \$390,000. The computed
6 reserve shown under the heading "PROPOSED BASIS" was
7 calculated based on the average service lives and life
8 tables proposed by me and in total amounted to
9 approximately \$391,000. The exhibit indicates that for
10 the total Gas Utility Plant the Accumulated Provision
11 for Depreciation per books is approximately \$35,400
12 less than the computed reserve based upon the "BOOK
13 BASIS" and approximately \$36,300 less than the computed
14 reserve based upon the "PROPOSED BASIS."

15 Q. What does the Company propose to do with this
16 variation?

17 A. In their direct testimony, the Company's Accounting
18 Panel sets forth a proposal to amortize this variation.

19 Q. What effect will your proposed changes have on annual
20 depreciation expense?

21 A. As I indicated earlier, the impact on annual
22 depreciation expense resulting from my proposals to
23 change average service lives amounts to \$597 annually.

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1 That amount is based on the book cost as of December
2 31, 2007 and is not reflective of plant changes in the
3 future. Therefore, the Accounting Panel has computed
4 the total changes to depreciation expense (see Exhibit
5 ____ (G-4, Schedule 9)) based on the rates I have
6 proposed, adjusted for a new level for the net salvage
7 allowance, as well as an adjustment to amortize the
8 reserve variation.

9 Q. Are there any other issues that you would like to
10 address at this time?

11 A. Yes. In accordance with PUC Docket C-20065942, the
12 Company has established a presence in Pennsylvania by
13 opening a new Customer Service Center in Milford,
14 Pennsylvania. Therefore, it is likely that various
15 common utility plant accounts will be opened to record
16 the related capital costs that will need to be
17 depreciated. In order to recover these costs, I
18 propose to amortize the costs related to the office
19 renovation over five years. For all other common
20 utility plant, I also propose to recover the costs by
21 amortizing them over five years. The all other common
22 utility plant is expected to consist of routine office
23 equipment like personal computers, telephones, desks,

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1 and chairs. Any future equipment that may need to be
2 added, or equipment that will replace retired
3 equipment, will be amortized over a new five year
4 amortization period beginning with their in-service
5 date.

6 Q. Does that conclude your testimony?

7 A. Yes, it does.

BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

In the matter of:

APPLICATION OF PIKE COUNTY)

LIGHT & POWER COMPANY FOR AN)

CASE NO. _____

INCREASE IN ELECTRIC AND GAS RATES)

TESTIMONY

OF

ROGER A. MORIN, PhD

July 2008

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PIKE COUNTY LIGHT & POWER COMPANY

TESTIMONY OF DR. ROGER A. MORIN

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1 **I. INTRODUCTION**

2 Q. Please state your name, address, and occupation.

3 A. My name is Dr. Roger A. Morin. My business address is Georgia State
4 University, Robinson College of Business, University Plaza, Atlanta, Georgia,
5 30303. I am Emeritus Professor of Finance at the Robinson College of Business,
6 Georgia State University and Professor of Finance for Regulated Industry at the
7 Center for the Study of Regulated Industry at Georgia State University. I am also
8 a principal in Utility Research International, an enterprise engaged in regulatory
9 finance and economics consulting to business and government.

10 Q. Please describe your educational background.

11 A. I hold a Bachelor of Engineering degree and an MBA in Finance from McGill
12 University, Montreal, Canada. I received my Ph.D. in Finance and Econometrics
13 at the Wharton School of Finance, University of Pennsylvania.

14 Q. Please summarize your academic and business career.

15 A. I have taught at the Wharton School of Finance, University of Pennsylvania,
16 Amos Tuck School of Business at Dartmouth College, Drexel University,
17 University of Montreal, McGill University, and Georgia State University. I was a
18 faculty member of Advanced Management Research International, and I am
19 currently a faculty member of The Management Exchange Inc. and Exnet, where I
20 continue to conduct frequent national executive-level education seminars
21 throughout the United States and Canada. In the last thirty years, I have
22 conducted numerous national seminars on "Utility Finance," "Utility Cost of
23 Capital," "Alternative Regulatory Frameworks," and on "Utility Capital
24 Allocation," which I have developed on behalf of The Management Exchange Inc.

1 in conjunction with Public Utilities Reports, Inc.

2 I have authored or co-authored several books, monographs, and articles in
3 academic scientific journals on the subject of finance. They have appeared in a
4 variety of journals, including The Journal of Finance, The Journal of Business
5 Administration, International Management Review, and Public Utility
6 Fortnightly. I published a widely-used treatise on regulatory finance, Utilities'
7 Cost of Capital, Public Utilities Reports, Inc., Arlington, Va. 1984. My second
8 book on regulatory matters, Regulatory Finance, is a voluminous treatise on the
9 application of finance to regulated utilities and was released by the same publisher
10 in late 1994. A revised and expanded edition, The New Regulatory Finance, was
11 published in 2006. I have engaged in extensive consulting activities on behalf of
12 numerous corporations, legal firms, and regulatory bodies in matters of financial
13 management and corporate litigation. Exhibit RAM-1 describes my professional
14 credentials in more detail.

15 Q. Have you previously testified on cost of capital before regulatory bodies?

16 A. Yes, I have been a cost of capital witness before nearly fifty (50) regulatory
17 bodies in North America, including the Pennsylvania Public Utility Commission
18 ("PPUC"), the Federal Energy Regulatory Commission and the Federal
19 Communications Commission. I have testified before regulatory bodies in the
20 following states:

Alabama	Hawaii	Montana	Ontario
Alaska	Illinois	Nevada	Oregon
Alberta	Indiana	New Brunswick	Pennsylvania
Arizona	Iowa	New Hampshire	Quebec
Arkansas	Kentucky	New Jersey	South Carolina
British Columbia	Louisiana	New York	South Dakota
California	Maine	Newfoundland	Tennessee
Colorado	Manitoba	North Carolina	Texas
Delaware	Michigan	North Dakota	Utah
District of Columbia	Minnesota	Nova Scotia	Vermont
Florida	Mississippi	Ohio	Washington
Georgia	Missouri	Oklahoma	West Virginia

1 The details of my participation in regulatory proceedings are provided in Exhibit
2 RAM-1.

3 Q. What is the purpose of your testimony in this proceeding?

4 A. The purpose of my testimony in this proceeding is to present an independent
5 appraisal of the fair and reasonable rate of return on the common equity capital
6 (“ROE”) invested in Pike County Power & Light Company’s (“PCPL” or the
7 “Company”) energy delivery operations in the State of Pennsylvania. Based
8 upon this appraisal, I have formed my professional judgment as to a return on
9 such capital that would: (1) be fair to customers, (2) allow the Company to attract
10 equity capital on reasonable terms, (3) maintain the Company’s financial
11 integrity, and (4) be comparable to returns offered on comparable risk
12 investments. I will testify in this proceeding as to the basis for that opinion.

13 This testimony and accompanying schedules were prepared by me or
14 under my direct supervision and control. The source documents for my testimony
15 are Company records, public documents, and my personal knowledge and
16 experience.

1

2 Q. Please briefly identify the schedules and appendices accompanying your
3 testimony.

4 A. I have attached to my testimony Exhibit RAM-1 through Exhibit RAM-8 and
5 Appendices A and B. These Exhibits and Appendices relate directly to points in
6 my testimony, and are described in further detail in connection with the
7 discussion of those points in my testimony.

8 Q. Please summarize your findings and recommendation.

9 A. I recommend the adoption of a ROE of 10.9% on PCPL's electric and gas
10 delivery operations. My recommendation is derived from studies that I performed
11 using the Capital Asset Pricing Model ("CAPM"), Risk Premium, and Discounted
12 Cash Flow ("DCF") methodologies. I performed two CAPM analyses, one using
13 the plain vanilla CAPM and another using an empirical approximation of the
14 CAPM ("ECAPM"). I performed two risk premium analyses: (1) a historical risk
15 premium analysis on the electric utility industry, and (2) a study of the risk
16 premiums allowed in the electric utility industry. I also performed DCF analyses
17 on two surrogates for the Company's electricity delivery business. They are: a
18 group of investment-grade electricity delivery utilities and a group consisting of
19 the companies that make up Moody's Electric Utility Index.

20 My recommended rate of return reflects the application of my professional
21 judgment to the indicated returns from my CAPM, Risk Premium, and DCF
22 analyses.

23 Q. Dr. Morin, please describe how your testimony is organized.

24 A. The remainder of my testimony is divided into three (3) sections:

- 1
- 2 I. Regulatory Framework and Rate of Return;
- 3 II. Cost of Equity Estimates; and
- 4 III. Summary and Cost of Equity Recommendation.

5 The first section discusses the rudiments of rate of return regulation and

6 the basic notions underlying rate of return. The second section contains the

7 application of CAPM, Risk Premium, and DCF tests. The third section

8 summarizes the results from the various approaches used in determining a fair

9 return.

10 **A. REGULATORY FRAMEWORK AND RATE OF RETURN**

11 Q. What economic and financial concepts have guided your assessment of PCPL's

12 cost of common equity?

13 A. Two fundamental economic principles underlie the appraisal of the Company's

14 cost of equity, one relating to the supply side of capital markets, the other to the

15 demand side. According to the first principle, a rational investor maximizes the

16 performance of his or her portfolio only if he or she expects the returns earned on

17 investments of comparable risk to be the same. If not, the rational investor will

18 switch out of those investments yielding lower returns at a given risk level in

19 favor of those investment activities offering higher returns for the same degree of

20 risk. This principle implies that a company will be unable to attract the capital

21 funds it needs to meet its service demands and to maintain financial integrity

22 unless it can offer returns to capital suppliers that are comparable to those

23 achieved on competing investments of similar risk. On the demand side, the

24 second principle asserts that a company will continue to invest in real physical

1 assets if the return on these investments exceeds or equals the company's marginal
2 cost of capital. This concept suggests that a regulatory commission should set
3 rates at a level sufficient to create at least equality between the return on physical
4 asset investments and the company's cost of capital.

5 Q. How does PCPL's cost of capital relate to that of its parent company, Orange and
6 Rockland Utilities, Inc. ("O&R")?

7 A. I am treating PCPL's electric/gas delivery operations as a separate stand-alone
8 entity, distinct from its holding company, O&R, because it is the cost of capital
9 for PCPL's electric and gas utility business that we are attempting to measure and
10 not the cost of capital for O&R's consolidated activities. Financial theory
11 establishes that the true cost of capital depends on the use to which the capital is
12 put, in this case PCPL's electric and gas delivery operations in the State of
13 Pennsylvania. The specific source of funding an investment and the cost of funds
14 to the investor are irrelevant considerations.

15 For example, if an individual investor borrows money at the bank at an
16 after-tax cost of 8% and invests the funds in a speculative oil extraction venture,
17 the required return on the investment is not the 8% cost but, rather, the return
18 foregone in speculative projects of similar risk, say 20%. Similarly, the required
19 return on PCPL is the return foregone in comparable risk electric delivery
20 operations, and is unrelated to the parent's cost of capital. The cost of capital is
21 governed by the risk to which the capital is exposed and not by the source of
22 funds. The identity of the shareholders has no bearing on the cost of equity, be it
23 either individual investors or a parent holding company.

24 Just as individual investors require different returns from different assets

1 in managing their personal affairs, corporations behave in the same manner. A
2 parent company normally invests money in many operating companies of varying
3 sizes and varying risks. These operating subsidiaries pay different rates for the
4 use of investor capital, such as for long-term debt capital, because investors
5 recognize the differences in capital structure, risk, and prospects between
6 subsidiaries. Thus, the cost of investing funds in an operating utility company
7 such as PCPL is the return foregone on investments of similar risk and is
8 unrelated to the investor's identity.

9 Q. Under traditional cost of service regulation, please explain how a regulated
10 company's rates should be set.

11 A. Under the traditional regulatory process, a regulated company's rates should be set
12 so that the company recovers its costs, including taxes and depreciation, plus a
13 fair and reasonable return on its invested capital. The allowed rate of return must
14 necessarily reflect the cost of the funds obtained, that is, investors' return
15 requirements. In determining a company's rate of return, the starting point is
16 investors' return requirements in financial markets. A rate of return can then be
17 set at a level sufficient to enable the company to earn a return commensurate with
18 the cost of those funds.

19 Funds can be obtained in two general forms, debt capital and equity
20 capital. The cost of debt funds can be easily ascertained from an examination of
21 the contractual interest payments. The cost of common equity funds, that is,
22 investors' required rate of return, is more difficult to estimate. It is the purpose of
23 the next section of my testimony to estimate PCPL's cost of common equity
24 capital.

1

2 Q. Dr. Morin, what must be considered in estimating a fair ROE?

3 A. The legal requirement is that the allowable ROE should be commensurate with
4 returns on investments in other firms having corresponding risks. The allowed
5 return should be sufficient to assure confidence in the financial integrity of the
6 firm, in order to maintain creditworthiness, and ability to attract capital on
7 reasonable terms. The attraction of capital standard focuses on investors' return
8 requirements that are generally determined using market value methods, such as
9 the Risk Premium, CAPM, or DCF methods. These market value tests define fair
10 return as the return that investors anticipate when they purchase equity shares of
11 comparable risk in the financial marketplace. This return is a market rate of
12 return, defined in terms of anticipated dividends and capital gains as determined
13 by expected changes in stock prices, and reflects the opportunity cost of capital.
14 The economic basis for market value tests is that new capital will be attracted to a
15 firm only if the return expected by the suppliers of funds is commensurate with
16 that available from alternative investments of comparable risk.

17 Q. What fundamental principles underlie the determination of a fair and reasonable
18 ROE?

19 A. The heart of utility regulation is the setting of just and reasonable rates by way of
20 a fair and reasonable return. There are two landmark United States Supreme Court
21 cases that define the legal principles underlying the regulation of a public utility's
22 rate of return and provide the foundations for the notion of a fair return:

23 1. Bluefield Water Works & Improvement Co. v. Public Service
24 Commission of West Virginia, 262 U.S. 679 (1923).

1 2. Federal Power Commission v. Hope Natural Gas Company, 320 U.S.
2 591 (1944).

3 The Bluefield case set the standard against which just and reasonable rates
4 of return are measured:

5 *A public utility is entitled to such rates as will permit it to earn a return on*
6 *the value of the property which it employs for the convenience of the public equal*
7 *to that generally being made at the same time and in the same general part of the*
8 *country on investments in other business undertakings which are attended by*
9 *corresponding risks and uncertainties ... The return should be reasonable,*
10 *sufficient to assure confidence in the financial soundness of the utility, and should*
11 *be adequate, under efficient and economical management, to maintain and*
12 *support its credit and enable it to raise money necessary for the proper discharge*
13 *of its public duties. (Emphasis added)*

14 The Hope case expanded on the guidelines to be used to assess the
15 reasonableness of the allowed return. The Court reemphasized its statements in
16 the Bluefield case and recognized that revenues must cover "capital costs." The
17 Court stated:

18 *From the investor or company point of view it is important that there be*
19 *enough revenue not only for operating expenses but also for the capital costs of*
20 *the business. These include service on the debt and dividends on the stock ... By*
21 *that standard the return to the equity owner should be commensurate with returns*
22 *on investments in other enterprises having corresponding risks. That return,*
23 *moreover, should be sufficient to assure confidence in the financial integrity of*
24 *the enterprise, so as to maintain its credit and attract capital. (Emphasis added)*

25 The United States Supreme Court reiterated the criteria set forth in Hope in
26 Federal Power Commission v. Memphis Light, Gas & Water Division, 411 U.S.
27 458 (1973), in Permian Basin Rate Cases, 390 U.S. 747 (1968), and most recently
28 in Duquesne Light Co. vs. Barasch, 488 U.S. 299 (1989). In the Permian cases,
29 the Supreme Court stressed that a regulatory agency's rate of return order should:

30 *...reasonably be expected to maintain financial integrity, attract necessary*
31 *capital, and fairly compensate investors for the risks they have assumed...*
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Therefore, the "end result" of the Commission's decision should be to allow PCPL the opportunity to earn a return on equity that is: (1) commensurate with returns on investments in other firms having corresponding risks, (2) sufficient to assure confidence in the Company's financial integrity, and (3) sufficient to maintain the Company's creditworthiness and ability to attract capital on reasonable terms.

Q. How is the fair rate of return determined?

A. The aggregate return required by investors is called the "cost of capital." The cost of capital is the opportunity cost, expressed in percentage terms, of the total pool of capital employed by the utility. It is the composite weighted cost of the various classes of capital (i.e., bonds, preferred stock, common stock) used by the utility, with the weights reflecting the proportions of the total capital that each class of capital represents. The fair return in dollars is obtained by multiplying the rate of return set by the regulator by the utility's "rate base." The rate base is essentially the net book value of the utility's plant and other assets used to provide utility service in a particular jurisdiction.

While utilities like PCPL enjoy varying degrees of monopoly in the sale of public utility services, they must compete with everyone else in the free, open market for the input factors of production, whether they be labor, materials, machines, or capital. The prices of these inputs are set in the competitive marketplace by supply and demand, and it is these input prices that are incorporated in the cost of service computation. This item is just as true for capital as for any other factor of production. Since utilities and other investor-

1 owned businesses must go to the open capital markets and sell their securities in
2 competition with every other issuer, there is obviously a market price to pay for
3 the capital they require, for example, the interest on debt capital, or the expected
4 market return on common and/or preferred equity.

5 Q. How does the concept of a fair return relate to the concept of opportunity cost?

6 A. The concept of a fair return is intimately related to the economic concept of
7 “opportunity cost.” When investors supply funds to a utility by buying its stocks
8 or bonds, they are not only postponing consumption, giving up the alternative of
9 spending their dollars in some other way, they also are exposing their funds to
10 risk and forgoing returns from investing their money in alternative comparable-
11 risk investments. The compensation that they require is the price of capital. If
12 there are differences in the risk of the investments, competition among firms for a
13 limited supply of capital will bring different prices. These differences in risk are
14 translated by the capital markets into price differences in much the same way that
15 differences in the characteristics of commodities are reflected in different prices.

16 The important point is that market prices of debt capital and equity capital
17 are set by supply and demand, and both are influenced by the relationship
18 between the risk and return expected for the respective securities and the risks
19 expected from the overall menu of available securities.

20 Q. How does the Company obtain its capital and how is its overall cost of capital
21 determined?

22 A. The funds employed by the Company are obtained in two general forms, debt
23 capital and equity capital. The latter consists of preferred equity capital and
24 common equity capital. The cost of debt funds and preferred stock funds can be

1 ascertained easily from an examination of the contractual terms for the interest
2 payments and preferred dividends. The cost of common equity funds, that is,
3 equity investors' required rate of return, is more difficult to estimate because the
4 dividend payments received from common stock are not contractual or guaranteed
5 in nature. They are uneven and risky, unlike interest payments. Once a cost of
6 common equity estimate has been developed, it can then easily be combined with
7 the embedded cost of debt and preferred stock, based on the utility's capital
8 structure, in order to arrive at the overall cost of capital.

9 Q. What is the market required rate of return on equity capital?

10 A. The market required rate of return on common equity, or cost of equity, is the
11 return demanded by the equity investor. Investors establish the price for equity
12 capital through their buying and selling decisions. Investors set return
13 requirements according to their perception of the risks inherent in the investment,
14 recognizing the opportunity cost of forgone investments, and the returns available
15 from other investments of comparable risk.

16 **II. COST OF EQUITY ESTIMATES**

17 Q. Dr. Morin, how did you estimate the fair ROE for PCPL?

18 A. I employed three methodologies: (1) the CAPM, (2) the Risk Premium, and (3)
19 the DCF. All three items are market-based methodologies and are designed to
20 estimate the return required by investors on the common equity capital committed
21 to PCPL.

22 Q. Why did you use more than one approach for estimating the cost of equity?

23 A. No one individual method provides the necessary level of precision for
24 determining a fair return, but each method provides useful evidence to facilitate

1 the exercise of an informed judgment. Reliance on any single method or preset
2 formula is inappropriate when dealing with investor expectations because of
3 possible measurement difficulties and vagaries in individual companies' market
4 data. Examples of such vagaries include dividend suspension, insufficient or
5 unrepresentative historical data due to a recent merger, impending merger or
6 acquisition, and a new corporate identity due to restructuring activities. The
7 advantage of using several different approaches is that the results of each one can
8 be used to check the others.

9 As a general proposition, it is extremely dangerous to rely on only one
10 generic methodology to estimate equity costs. The difficulty is compounded
11 when only one variant of that methodology is employed. It is compounded even
12 further when that one methodology is applied to a single company. Hence,
13 several methodologies applied to several comparable risk companies should be
14 employed to estimate the cost of common equity.

15 Q. Dr. Morin, are you aware that some regulatory commissions and some analysts
16 have placed principal reliance on DCF-based analyses to determine the cost of
17 equity for public utilities?

18 A. Yes, I am.

19 Q. Do you agree with this approach?

20 A. While I agree that it is certainly appropriate to use the DCF methodology to
21 estimate the cost of equity, and I myself do rely on such evidence, there is no
22 proof that the DCF produces a more accurate estimate of the cost of equity than
23 other methodologies. As I have stated, there are three broad generic
24 methodologies available to measure the cost of equity: DCF, Risk Premium, and

1 CAPM. All three of these methodologies are accepted and used by the financial
2 community and firmly supported in the financial literature.

3 When measuring the cost of common equity, which essentially deals with
4 the measurement of investor expectations, no one single methodology provides a
5 foolproof panacea. Each methodology requires the exercise of considerable
6 judgment on the reasonableness of the assumptions underlying the methodology
7 and on the reasonableness of the proxies used to validate the theory and apply the
8 methodology. The failure of the traditional infinite growth DCF model to account
9 for changes in relative market valuation, and the practical difficulties of
10 specifying the expected growth component, are vivid examples of the potential
11 shortcomings of the DCF model. It follows that more than one methodology
12 should be employed in arriving at a judgment on the cost of equity and that all of
13 these methodologies should be applied to multiple groups of comparable risk
14 companies.

15 There is no single model that conclusively determines or estimates the
16 expected return for an individual firm. Each methodology has its own way of
17 examining investor behavior, its own premises, and its own set of simplifications
18 of reality. Investors do not necessarily subscribe to any one method, nor does the
19 market price of a share reflect the application of any one single method by the
20 price-setting investor. Absent any hard evidence as to which method outperforms
21 the other, all relevant evidence should be used, without discounting the value of
22 any results, in order to minimize judgmental error, measurement error, and
23 conceptual infirmities. I submit that a regulatory body should rely on the results
24 of a variety of methods applied to a variety of comparable groups. There is no

1 guarantee that a single DCF result is necessarily the ideal predictor of the market
2 price of a share and of the market cost of equity reflected in that price, just as
3 there is no guarantee that a single CAPM or Risk Premium result constitutes the
4 perfect explanation of a stock's price or the cost of equity.

5 Q. Does the financial literature support the use of more than a single method?

6 A. Yes. Authoritative financial literature strongly supports the use of multiple
7 methods. For example, Professor Eugene F. Brigham, a widely respected scholar
8 and finance academician, discusses the various methods used in estimating the
9 cost of common equity capital, and states (see E. F. Brigham and M. C. Ehrhardt,
10 Financial Management Theory and Practice, p. 311 (11th ed., Thomson South-
11 Western, 2005):

12 *Three methods typically are used: (1) the Capital Asset Pricing Model (CAPM),*
13 *(2) the discounted cash flow (DCF) model, and (3) the bond-yield-plus-risk-*
14 *premium approach. These methods are not mutually exclusive - no method*
15 *dominates the others, and all are subject to error when used in practice.*
16 *Therefore, when faced with the task of estimating a company' cost of equity, we*
17 *generally use all three methods....*

18 Another prominent finance scholar, Professor Stewart Myers, points out
19 (see S. C. Myers, "On the Use of Modern Portfolio Theory in Public Utility Rate
20 Cases: Comment," Financial Management, p. 67, Autumn 1978):

21 *Use more than one model when you can. Because estimating the opportunity cost*
22 *of capital is difficult, only a fool throws away useful information. That means you*
23 *should not use any one model or measure mechanically and exclusively. Beta is*
24 *helpful as one tool in a kit, to be used in parallel with DCF models or other*
25 *techniques for interpreting capital market data.*

26 Q. Does the broad use of the DCF methodology in past regulatory proceedings
27 indicate that it is superior to other methods?

28 A. No, it does not. Uncritical acceptance of the standard DCF equation vests the

1 model with a degree of reliability that is simply not justified. One of the leading
2 experts on regulation, Dr. Charles F. Phillips discusses the dangers of relying
3 solely on the DCF model:

4 *[U]se of the DCF model for regulatory purposes involves both theoretical and*
5 *practical difficulties. The theoretical issues include the assumption of a constant*
6 *retention ratio (i.e. a fixed payout ratio) and the assumption that dividends will*
7 *continue to grow at a rate 'g' in perpetuity. Neither of these assumptions has any*
8 *validity, particularly in recent years. Further, the investors' capitalization rate*
9 *and the cost of equity capital to a utility for application to book value (i.e. an*
10 *original cost rate base) are identical only when market price is equal to book*
11 *value. Indeed, DCF advocates assume that if the market price of a utility's*
12 *common stock exceeds its book value, the allowable rate of return on common*
13 *equity is too high and should be lowered; and vice versa. Many question the*
14 *assumption that market price should equal book value, believing that the earnings*
15 *of utilities should be sufficiently high to achieve market-to-book ratios which are*
16 *consistent with those prevailing for stocks of unregulated companies.*

17
18 *...[T]here remains the circularity problem: Since regulation establishes a level of*
19 *authorized earnings which, in turn, implicitly influences dividends per share,*
20 *estimation of the growth rate from such data is an inherently circular process.*
21 *For all of these reasons, the DCF model suggests a degree of precision which is*
22 *in fact not present and leaves wide room for controversy about the level of k [cost*
23 *of equity].¹*
24

25 Sole reliance on any one model, whether it is DCF, CAPM, or Risk
26 Premium, simply ignores the capital market evidence and investors' use of the
27 other theoretical frameworks. The DCF model is only one of many tools to be
28 employed in conjunction with other methods to estimate the cost of equity. It is
29 not a superior methodology that should supplant other financial theory and market
30 evidence. The same is true of the CAPM.

31 Q. Does the manner in which the regulator applies the DCF model understate the
32 cost of equity?

¹ C.F. Phillips, The Regulation of Public Utilities Theory and Practice (Public Utilities Reports, Inc., 1988)
pp. 376-77 [Footnotes omitted]

1 A. Applying the market rate of return to the book value of equity understates the
2 required return on book equity under current capital market conditions.
3 Application of the DCF model produces estimates of common equity cost that are
4 consistent with investors' expected return only when stock price and book value
5 are reasonably similar, that is, when the Market-to-Book ("M/B") ratio is close to
6 unity. As shown below, application of the standard DCF model does not account
7 for the investor's expected return when the M/B ratio of a given stock deviates
8 from unity. This item is particularly relevant in the current capital market
9 environment where stocks in general and utility stocks in particular are trading at
10 M/B ratios well above unity and have been for two decades. The converse is also
11 true, that is, the DCF model overstates the investor's return when the stock's M/B
12 ratio is less than unity. The reason for the distortion is that the DCF market return
13 is applied to a book value rate base by the regulator, that is, a utility's earnings are
14 limited to earnings on a book value rate base.

15 Q. What are the results of this distortion?

16 A. The return given to equity investors is lower than what they actually require when
17 M/B ratios exceed unity. This is neither equitable for the existing stockholders
18 nor efficient from the point of view of attracting capital to cover the significant
19 capital expenditures that need to be undertaken.

20 Q. Can you illustrate the effect of the M/B ratio on the applicability of the DCF
21 model by means of a simple example?

22 A. Yes. The simple numerical illustration shown in the table below demonstrates the
23 result of applying a market value cost rate to book value rate base under three
24 different M/B scenarios. The three columns correspond to three M/B situations:

1 the stock trades below, equal to, and above book value, respectively. The last
2 situation (third column of numbers) is noteworthy and representative of the
3 current capital market environment. The DCF cost rate of 10%, made up of a 5%
4 dividend yield and a 5% growth rate, is applied to the book value rate base of \$50
5 to produce \$5.00 of earnings. Of the \$5.00 of earnings, the full \$5.00 are required
6 for dividends to produce a dividend yield of 5% on a stock price of \$100.00, and
7 no dollars are available for growth. The investor's return is therefore only 5%
8 versus his required return of 10%. A DCF cost rate of 10%, which implies \$10.00
9 of earnings, translates to only \$5.00 of earnings on book value, a 5% return.

10 The situation is reversed in the first column when the stock trades below
11 book value. The \$5.00 of earnings is more than enough to satisfy the investor's
12 dividend requirements of \$1.25, leaving \$3.75 for growth, for a total return of
13 20%. This item occurs when the DCF cost rate is applied to a book value rate
14 base well above the market price.

15 Therefore, the DCF cost rate significantly understates the investor's
16 required return when stock prices are well above book, as is the case presently.

EFFECT OF MARKET-TO-BOOK RATIO ON MARKET RETURN

	Situation	1	2	3
1	Initial purchase price	\$25	\$50	\$100
2	Initial book value	\$50	\$50	\$50
3	Initial M/B	0.50	1.00	2.00
4	DCF Return 10% = 5% + 5%	10%	10%	10%
5	Dollar Return	\$5.00	\$5.00	\$5.00
6	Dollar Dividends 5% Yield	\$1.25	\$2.50	\$5.00
7	Dollar Growth 5% Growth	\$3.75	\$2.50	\$0.00
8	Market Return	20%	10%	5%

17 Q. Does the annual version of the DCF model understate the cost of equity?

1 A. Yes, it does. Another reason why the DCF methodology understates the cost of
2 equity is that the annual DCF model usually employed in regulatory settings
3 assumes that dividend payments are made annually at the end of the year, while
4 most utilities in fact pay dividends on a quarterly basis. Failure to recognize the
5 quarterly nature of dividend payments understates the cost of equity capital by
6 about 30 basis points. By analogy, a bank rate on deposit that does not take into
7 consideration the timing of the interest payments understates the true yield of your
8 investment if you receive the interest payments more than once a year. Since the
9 stock price employed in the DCF model already reflects the quarterly stream of
10 dividends to be received, consistency therefore requires explicit recognition of the
11 quarterly nature of dividend payments. One only has to think of what would
12 happen to a company's stock price if the company was to suddenly announce that
13 it is, from now on, paying dividends once a year at the end of the year instead of
14 four times a year each quarter. Clearly, the stock price would decline by an
15 amount reflecting the lost time value of money.

16 Q. Do regulators rely primarily on the DCF model?

17 A. A majority of regulatory commissions do not, as a matter of practice, rely solely
18 on the DCF model results in setting the allowed rate of return on common equity.
19 According to the survey results posted in the Utility Regulatory Policy in the
20 United States and Canada – 1994-1995 Compilation which was conducted by the
21 National Association of Regulatory Utility Commissioners (“NARUC”),
22 regulators employ a variety of methods and rely on all the evidence submitted.

23 Q. Do regulators share your reservations on the reliability of the DCF model?

1 A. Yes, I believe they do. While a majority of regulatory commissions do not, as a
2 matter of practice, rely solely on the DCF model results in setting the allowed
3 ROE, some regulatory commissions have explicitly recognized the need to avoid
4 exclusive reliance upon the DCF model and have acknowledged the need to adjust
5 the DCF result when M/B ratios exceed one². In a recent case involving Pacific
6 Bell Telephone Company, the California Commission (Application No. 01-02-
7 024, Joint Application of ATT Communications, Opinion Establishing Revised
8 Unbundled Network Element Rates at VI.N, October 2004) declined to place any
9 reliance on the DCF method, finding that it was “too dependent on one forecasted
10 input.”

11 My sentiments on the DCF model were echoed in a decision by the
12 Indiana Utility Regulatory Commission (“IURC”). The IURC recognized its
13 concerns with the DCF model and that the model understates the cost of equity.
14 In Cause No. 39871 Final Order, the IURC states on page 24:

15 *....the DCF model, heavily relied upon by the Public, understates the cost of*
16 *common equity. The Commission has recognized this fact before. In Indiana*
17 *Mich. Power Co. (IURC 8/24/90), Cause No. 38728, 116 PUR4th 1, 17-18, we*
18 *found:*

19 *The unadjusted DCF result is almost always well below what any informed*
20 *financial analyst would regard as defensible, and therefore requires an upward*
21 *adjustment based largely on the expert witness’s judgment.*
22

23 The Commission also expressed its concern with a witness relying solely
24 on one methodology:

² See the Indiana Utility Regulatory Commission decision in Indiana Mich. Power Co. (IURC 8/24/90), Cause No. 38728, 116 PUR4th 1, 17-18. See also the Iowa Utilities Board decision in U.S. West Communications, Inc. Docket No. RPR-93-9, 152 PUR4th 446, 459 (Iowa 1994). See also the Hawaii Public Utilities Commission decision in Hawaiian Electric Company, Inc., 134 PUR4th 418, 479

1 the Commission has had concerns in our past orders with a witness relying
2 solely on one methodology in reaching an opinion on a proper return on equity
3 figure. (page 25)
4
5

6 Even more convincing evidence that regulators have in fact not relied on
7 the DCF model exclusively is the fact that M/B ratios have exceeded unity for
8 over two decades. Had regulators relied exclusively on the DCF model, utility
9 stocks would have traded at or near book value. Regulators have “corrected” for
10 this M/B problem by considering other methods for estimating capital cost.

11 Q. Is the usage of the DCF model prevalent in corporate practices?

12 A. No, not really. The CAPM continues to be widely used by analysts, investors, and
13 corporations. Bruner, Eades, Harris, and Higgins (1998) in a comprehensive survey³
14 of current practices for estimating the cost of capital found that 81% of companies
15 used the CAPM to estimate the cost of equity, 4% used a modified CAPM, and 15%
16 were uncertain. In another comprehensive survey conducted by Graham and
17 Harvey (2001), the managers surveyed reported using more than one methodology
18 to estimate the cost of equity, and 73% used the CAPM.⁴ Since its introduction by
19 Professor William F. Sharpe in 1964, the CAPM has gained immense popularity
20 as the practitioner’s method of choice when estimating cost of capital under
21 conditions of risk.⁵ The intuitive simplicity of its basic concept (that investors
22 must get compensated for the risk they assume), and the relatively easy

(1992). More recently, see the Pennsylvania Public Utility Commission decision in Pennsylvania-American Water Co., Docket R-00016339.

³ Bruner, R. F., Eades, K. M., Harris, R. S., and Higgins, R. C., “Best Practices in Estimating the Cost of Capital: Survey and Synthesis,” *Financial Practice and Education*, Vol. 8, Number 1, Spring/Summer 1998, page 18.

⁴ Graham, J. R. and Harvey, C. R., “The Theory and Practice of Corporate Finance: Evidence from the Field,” *Journal of Financial Economics*, Vol. 61, 2001, pp. 187-243.

⁵ See practitioner surveys by Graham & Harvey (2001) and Bruner, et. al. (1988)

1 application of the CAPM are the main reasons behind its popularity.

2 Q. Do the assumptions underlying the DCF model require that the model be treated
3 with caution?

4 A. Yes, particularly in today's rapidly changing electric utility industry. Even
5 ignoring the fundamental thesis that several methods and/or variants of such
6 methods should be used in measuring equity costs, the DCF methodology, as
7 those familiar with the industry and the accepted norms for estimating the cost of
8 equity are aware, is problematic for use in estimating cost of equity at this time.

9 Several fundamental structural changes have transformed the energy
10 utility industry since the standard DCF model and its assumptions were
11 developed. For example, deregulation, accounting rule changes, changes in
12 customer attitudes regarding utility services, the evolution of alternative energy
13 sources, highly volatile fuel prices, and mergers-acquisitions have all influenced
14 stock prices in ways that have deviated substantially from the assumptions of the
15 DCF model, which was first formulated in the mid-1970s. These changes suggest
16 that (1) some of the fundamental assumptions underlying the standard DCF
17 model, particularly that of constant growth and constant relative market valuation,
18 for example price/earnings ("P/E") ratios and M/B ratios, are problematic at this
19 point in time for utility stocks, and (2) therefore, alternate methodologies to
20 estimate the cost of common equity should be accorded at least as much weight as
21 the DCF method.

22 Q. Is the constant relative market valuation assumption inherent in the DCF model
23 always reasonable?

24 A. No, not always. Caution must be exercised when implementing the standard DCF

1 model in a mechanistic fashion, for it may fail to recognize changes in relative
2 market valuations over time. The traditional DCF model is not equipped to deal
3 with surges in P/E ratios and M/B multiples. The standard DCF model assumes a
4 constant market valuation multiple, that is, a constant P/E ratio and a M/B ratio.
5 Stated another way, the model assumes that investors expect the ratio of market
6 price to dividends (or earnings) in any given year to be the same as the current
7 ratio of market price to dividend (or earnings). This item is a necessary result of
8 the infinite growth assumption. This assumption is unrealistic under current
9 conditions.

10 Q. What is your recommendation given such market conditions?

11 A. In short, caution and judgment are required in interpreting the results of the
12 standard DCF model because of (1) the effect of changes in risk and growth on
13 electric utilities, (2) the fragile applicability of the DCF model to electric utilities
14 stocks in the current capital market environment, and (3) the practical difficulties
15 associated with the growth component of the standard DCF model. Hence, there
16 is a clear need to go beyond the standard DCF results and take into account the
17 results produced by alternate methodologies in arriving at a common equity
18 recommendation.

19 Q. What weight would you give the DCF model in determining a utility company's
20 cost of common equity capital?

21 A. As stated earlier, there is no single model that conclusively determines or
22 estimates the expected return for an individual firm. Absent any hard evidence as
23 to which method outperforms the other, all relevant evidence should be used,
24 without discounting the value of any results, in order to minimize judgmental

1 error, measurement error, and conceptual infirmities. I submit that a regulatory
2 body should rely on the results of a variety of methods applied to a variety of
3 comparable groups. I would therefore ascribe equal weight to the various
4 methodologies. I do note that the DCF model has more questionable underlying
5 assumptions than do other models at this time.

6 Q. Do the assumptions underlying the CAPM require that the model be treated with
7 caution?

8 A. Yes, as was the case with the DCF model, the assumptions underlying any model
9 in the social sciences, including the CAPM, are stringent. Moreover, the
10 empirical validity of the CAPM has been the subject of intense research in recent
11 years. Although the CAPM provides useful evidence, it must be complemented
12 by other methodologies as well.

13 Q. As a theoretical matter, why should the CAPM be used as a tool to estimate utility
14 capital costs in regulatory proceedings?

15 A. As a tool in the regulatory arena, the CAPM is a rigorous conceptual framework,
16 and is logical insofar as it is not subject to circularity problems, since its inputs are
17 objective, market-based quantities, largely immune to regulatory decisions. The
18 data requirements of the model are not prohibitive. The CAPM is one of several
19 tools in the arsenal of techniques to determine the cost of equity capital. Caution,
20 appropriate training in finance and econometrics, and judgment are required for its
21 successful execution, as is the case with the DCF and Risk Premium methodologies.

22 **A.RISK PREMIUM ANALYSES**

23 Q. Dr. Morin, please provide an overview of your risk premium analyses.

1 A. In order to quantify the risk premium for PCPL, I have performed four risk
2 premium studies. The first two studies deal with aggregate stock market risk
3 premium evidence using two versions of the CAPM methodology and the other
4 two studies deal directly with the electric utility industry.

5 1. CAPM ESTIMATES

6 Q. Please describe your application of the CAPM risk premium approach.

7 A. My first two risk premium estimates are based on the CAPM and on an empirical
8 approximation to the CAPM (“ECAPM”). The CAPM is a fundamental paradigm
9 of finance. Simply put, the fundamental idea underlying the CAPM is that risk-
10 averse investors demand higher returns for assuming additional risk, and higher-
11 risk securities are priced to yield higher expected returns than lower-risk
12 securities. The CAPM quantifies the additional return, or risk premium, required
13 for bearing incremental risk. It provides a formal risk-return relationship
14 anchored on the basic idea that only market risk matters, as measured by beta.
15 According to the CAPM, securities are priced such that their:

$$16 \text{ EXPECTED RETURN} = \text{RISK-FREE RATE} + \text{RISK PREMIUM}$$

17 Denoting the risk-free rate by R_F and the return on the market as a whole
18 by R_M , the CAPM is:

$$19 K = R_F + \beta (R_M - R_F)$$

20 This is the seminal CAPM expression, which states that the return required
21 by investors is made up of a risk-free component, R_F , plus a risk premium
22 determined by $\beta(R_M - R_F)$. To derive the CAPM risk premium estimate, three
23 quantities are required: the risk-free rate (R_F), beta (β), and the market risk
24 premium, $(R_M - R_F)$. For the risk-free rate, I used 4.6% based on the current level

1 of long-term Treasury interest rates. For beta, I used 0.82 and for the market risk
2 premium (“MRP”), I used 7.3%. These inputs to the CAPM are explained below.

3 Q. What risk-free rate did you use in your CAPM and risk premium analyses?

4 A. To implement the CAPM and Risk Premium methods, an estimate of the risk-free
5 return is required as a benchmark. As a proxy for the risk-free rate, I have relied
6 on the current level of 30-year Treasury bond yields.

7 The appropriate proxy for the risk-free rate in the CAPM is the return on
8 the longest term Treasury bond possible. This is because common stocks are very
9 long-term instruments more akin to very long-term bonds rather than to short-
10 term or intermediate-term Treasury notes. In a risk premium model, the ideal
11 estimate for the risk-free rate has a term to maturity equal to the security being
12 analyzed. Since common stock is a very long-term investment because the cash
13 flows to investors in the form of dividends last indefinitely, the yield on the
14 longest-term possible government bonds, that is the yield on 30-year Treasury
15 bonds, is the best measure of the risk-free rate for use in the CAPM. The
16 expected common stock return is based on very long-term cash flows, regardless
17 of an individual's holding time period. Moreover, utility asset investments
18 generally have very long-term useful lives and should correspondingly be
19 matched with very long-term maturity financing instruments.

20 While long-term Treasury bonds are potentially subject to interest rate
21 risk, this is only true if the bonds are sold prior to maturity. A substantial fraction
22 of bond market participants, usually institutional investors with long-term
23 liabilities (pension funds, insurance companies), in fact hold bonds until they
24 mature, and therefore are not subject to interest rate risk. Moreover, institutional

1 bondholders neutralize the impact of interest rate changes by matching the
2 maturity of a bond portfolio with the investment planning period, or by engaging
3 in hedging transactions in the financial futures markets. The merits and
4 mechanics of such immunization strategies are well documented by both
5 academicians and practitioners.

6 Another reason for using the longest maturity Treasury bond possible is
7 that common equity has an infinite life span, and the inflation expectations
8 embodied in its market-required rate of return will therefore be equal to the
9 inflation rate anticipated to prevail over the very long-term. The same
10 expectation should be embodied in the risk-free rate used in applying the CAPM
11 model. It stands to reason that the yields on 30-year Treasury bonds will more
12 closely incorporate within their yield the inflation expectations that influence the
13 prices of common stocks than do short-term or intermediate-term U.S. Treasury
14 notes.

15 Among U.S. Treasury securities, 30-year Treasury bonds have the longest
16 term to maturity and the yield on such securities should be used as proxies for the
17 risk-free rate in applying the CAPM, provided there are no anomalous conditions
18 existing in the 30-year Treasury market. In the absence of such conditions, I have
19 relied on the yield on 30-year Treasury bonds in implementing the CAPM and
20 risk premium methods.

Q. Dr. Morin, why did you reject short-term interest rates as proxies for the risk-free
rate in implementing the CAPM?

21 A. Short-term rates are volatile, fluctuate widely, and are subject to more random
22 disturbances than are long-term rates. Short-term rates are largely administered

1 rates. For example, Treasury bills are used by the Federal Reserve as a policy
2 vehicle to stimulate the economy and to control the money supply, and are used
3 by foreign governments, companies, and individuals as a temporary safe-house
4 for money.

5 As a practical matter, it makes no sense to match the return on common
6 stock to the yield on 90-day Treasury Bills. This is because short-term rates, such
7 as the yield on 90-day Treasury Bills, fluctuate widely, leading to volatile and
8 unreliable equity return estimates. Moreover, yields on 90-day Treasury Bills
9 typically do not match the equity investor's planning horizon. Equity investors
10 generally have an investment horizon far in excess of 90 days.

11 As a conceptual matter, short-term Treasury bill yields reflect the impact
12 of factors different from those influencing the yields on long-term securities such
13 as common stock. For example, the premium for expected inflation embedded
14 into 90-day Treasury Bills is likely to be far different than the inflationary
15 premium embedded into long-term securities yields. On grounds of stability and
16 consistency, the yields on long-term Treasury bonds match more closely with
17 common stock returns.

18 Q. What is the current level of U.S. Treasury 30-year bonds?

19 A. The yield on U.S. Treasury 30-year bonds prevailing in July 2008, as reported in
20 Value Line and the Federal Reserve Bank Web site, was 4.6%. Accordingly, I
21 use 4.6% as my estimate of the risk-free rate component of the CAPM.

22 Q. How did you select the beta for your CAPM analysis?

23 A. A major thrust of modern financial theory as embodied in the CAPM is that
24 perfectly diversified investors can eliminate the company-specific component of

1 risk, and that only market risk remains. The latter is technically known as "beta",
2 or "systematic risk". The beta coefficient measures the change in a security's
3 return relative to that of the market. The beta coefficient states the extent and
4 direction of movement in the rate of return on a stock relative to the movement in
5 the rate of return on the market as a whole. The beta coefficient indicates the
6 change in the rate of return on a stock associated with a one percentage point
7 change in the rate of return on the market, and, thus, measures the degree to which
8 a particular stock shares the risk of the market as a whole. Modern financial
9 theory has established that beta incorporates several economic characteristics of a
10 corporation which are reflected in investors' return requirements.

11 Technically, the beta of a stock is a measure of the covariance of the
12 returns of a stock with the returns of the market as a whole. Accordingly, it
13 measures dispersion in a stock's return that cannot be reduced through
14 diversification. For a large diversified portfolio, dispersion in the market rate of
15 return on the entire portfolio is the weighted sum of the beta coefficients of its
16 constituent stocks.

17 PCPL is not publicly-traded and, therefore, proxies must be used for
18 PCPL. As a first proxy for the Company's beta, I have examined the betas of a
19 sample of widely-traded investment-grade dividend-paying electric utilities
20 designated as distribution utilities by S&P covered by Value Line and with at
21 least 50% of their revenues from electric utility operations. This group is
22 examined in more detail later in my testimony, in connection with the DCF
23 estimates of the cost of common equity. As displayed on page 1 of Exhibit
24 RAM-2, the average beta for the group is currently 0.82.

1 I also examined the average beta of the companies that make up Moody's
2 Electric Utility Index as a second proxy for the Company. As shown on page 2 of
3 Exhibit RAM-2, the average beta of the Moody's group is 0.84. If those
4 companies with less than 50% of their revenues from electric utility operations are
5 removed from the group, the average beta of the remaining companies is 0.83, as
6 shown on page 3 of Exhibit RAM-2. Based on these results, I shall use 0.82 as a
7 beta estimate for PCPL's electric and gas delivery operations.

8 Q. Did you consider analyzing a group of natural gas distributors as a proxy for
9 PCPL's energy distribution business?

10 A. Yes, I did but chose not to analyze a separate group of natural gas distribution
11 utilities for two reasons. First, PCPL's energy distribution business consists
12 primarily of electricity distribution which makes up the majority of its operating
13 income. Second, the sample of pure-play natural gas distribution utilities has
14 dwindled considerably in recent years. Several former natural gas distributors are
15 no longer publicly traded as a result of merger and acquisitions (e.g. Cascade,
16 Keyspan), and several others now possess significant unregulated energy trading
17 operations (e.g. New Jersey Resources, AGL Resources, Atmos Energy).
18 Therefore, I have relied on two samples of electric utilities, as proxies for PCPL.

19 Q. What MRP estimate did you use in your CAPM analysis?

20 A. For the MRP, I used 7.3%. This estimate was based on the results of both
21 forward-looking and historical studies of long-term risk premiums. First, the
22 Ibbotson Associates (now Morningstar) study, Stocks, Bonds, Bills, and Inflation,
23 2008 Yearbook, compiling historical returns from 1926 to 2007, shows that a
24 broad market sample of common stocks outperformed long-term U. S. Treasury

1 bonds by 6.5%. The historical MRP over the income component of long-term
2 Treasury bonds rather than over the total return is 7.1%. The Morningstar study
3 recommends the use of the latter as a more reliable estimate of the historical
4 MRP, and I concur with this viewpoint. The historical MRP should be computed
5 using the income component of bond returns because the intent, even using
6 historical data, is to identify an expected MRP. The more accurate way to
7 estimate the MRP from historic data is to use the income return, not total returns
8 on government bonds, as explained at pages 75-77 of Morningstar's Stocks,
9 Bonds, Bills, and Inflation: Valuation Edition, 2007 Yearbook. This is because
10 the income component of total bond return (i.e., the coupon rate) is a far better
11 estimate of expected market return than the total return (i.e., the coupon rate +
12 capital gain), as realized capital gains/losses are largely unanticipated by bond
13 investors. The long-horizon (1926-2007) MRP (based on income returns, as
14 required) is specifically calculated to be 7.1% rather than 6.5%.

15 Second, a DCF analysis applied to the aggregate equity market using the
16 S&P 500 Index and Value Line growth forecasts indicates a prospective MRP of
17 7.5%. Therefore, I shall employ the average of the two estimates, 7.3%, as a
18 reasonable estimate of the MRP.

19 **Historical Market Risk Premium**

20 Q. On what maturity bond does the Morningstar historical risk premium data rely
21 upon?

22 A. Because 30-year bonds were not always traded or even available throughout the
23 entire 1926-2007 period covered in the Morningstar Study of historical returns,

1 the latter study relied on bond return data based on 20-year Treasury bonds. To
2 the extent that the normal yield curve is virtually flat above maturities of 20 years
3 over most of the period covered in the Ibbotson study, the difference in yield is
4 not material. In fact, the difference in yield between 30-year and 20-year bonds is
5 actually negative. The average difference in yield over the 1977-2007 period is
6 approximately 13 basis points, that is, the yield on 20-year bonds is slightly
7 higher than the yield on 30-year bonds.

8 Q. Why did you use long time periods in arriving at your historical MRP estimate?

9 A. Because realized returns can be substantially different from prospective returns
10 anticipated by investors when measured over short time periods, it is important to
11 employ returns realized over long time periods rather than returns realized over
12 more recent time periods when estimating the MRP with historical returns.
13 Therefore, a risk premium study should consider the longest possible period for
14 which data are available. Short-run periods during which investors earned a
15 lower risk premium than they expected are offset by short-run periods during
16 which investors earned a higher risk premium than they expected. Only over long
17 time periods will investor return expectations and realizations converge.

18 I have therefore ignored realized risk premiums measured over short time
19 periods, since they are heavily dependent on short-term market movements.
20 Instead, I relied on results over periods of enough length to smooth out short-term
21 aberrations, and to encompass several business and interest rate cycles. The use
22 of the entire study period in estimating the appropriate MRP minimizes subjective
23 judgment and encompasses many diverse regimes of inflation, interest rate cycles,
24 and economic cycles.

1 To the extent that the estimated historical equity risk premium follows
2 what is known in statistics as a “random walk,” the best estimate of the future risk
3 premium is the historical mean. Since I found no evidence that the MRP in
4 common stocks has changed over time, that is, no significant serial correlation in
5 the Ibbotson study, it is reasonable to assume that these quantities will remain
6 stable in the future.

7 **Prospective Market Risk Premium**

8 Q. Please describe your prospective approach in deriving the MRP in the CAPM
9 analysis.

10 A. For my prospective estimate of the MRP, I applied a DCF analysis to the
11 aggregate equity market using Value Line's VLIA software. The dividend yield
12 on the stocks that make up the S&P 500 Index is currently 1.78% (VLIA 06/2008
13 edition), and the average projected long-term growth rate in dividends is 10.21%.
14 Adding the dividend yield to the growth component produces an expected return
15 on the aggregate equity market of 11.99%. Following the tenets of the DCF
16 model, the spot dividend yield must be converted into an expected dividend yield
17 by multiplying it by one plus the growth rate. This brings the expected return on
18 the aggregate equity market to 12.17%. Recognition of the quarterly timing of
19 dividend payments rather than the annual timing of dividends assumed in the
20 annual DCF model brings the MRP estimate to approximately 12.37%.
21 Subtracting the risk-free rate of 4.6% from the latter, the implied risk premium is
22 7.77% over long-term U.S. Treasury bonds.

23 Q. Did you check your MRP estimate of 7.3% from any other source?

1 A. Yes, I did. As a check on the MRP estimate, I examined a 2003 comprehensive
2 article published in Financial Management (see Harris, R. S., Marston, F. C.,
3 Mishra, D. R., and O'Brien, T. J., "*Ex Ante* Cost of Equity Estimates of S&P 500
4 Firms: The Choice Between Global and Domestic CAPM," Financial
5 Management, Autumn 2003, pp. 51-66).

6 These authors provide estimates of the prospective expected market
7 returns for S&P 500 companies over the period 1983-1998. They measure the
8 expected market rate of return of each dividend-paying stock in the S&P 500 for
9 each month from January 1983 to August 1998 by using the constant growth DCF
10 model. The prevailing risk-free rate for each year was then subtracted from the
11 expected rate of return for the overall market to arrive at the market risk premium
12 for that year. The table below, drawn from Table 2 of the aforementioned study,
13 displays the average prospective MRP estimate (Column 2) for each year from
14 1983 to 1998. The average MRP estimate for the overall period is 7.2%, which is
15 very close to my own estimate of 7.3%.

16
17

1		DCF Market
2	<u>Year</u>	<u>Risk Premium</u>
3	1983	6.6%
4	1984	5.3%
5	1985	5.7%
6	1986	7.4%
7	1987	6.1%
8	1988	6.4%
9	1989	6.6%
10	1990	7.1%
11	1991	7.5%
12	1992	7.8%
13	1993	8.2%
14	1994	7.3%
15	1995	7.7%
16	1996	7.8%
17	1997	8.2%
18	1998	9.2%
19	MEAN	7.2%

20

21 Q. What is your estimate of PCPL's cost of equity using the CAPM approach?

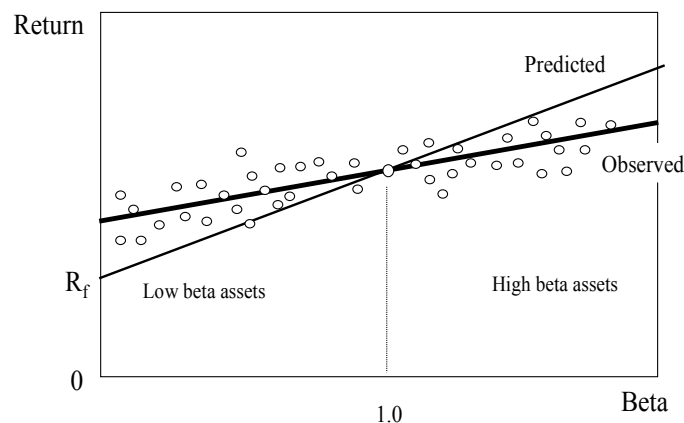
22 A. Inserting those input values in the CAPM equation, namely a risk-free rate of
 23 4.6%, a beta of 0.82, and a MRP of 7.3%, the CAPM estimate of the cost of
 24 common equity for PCPL is: $4.6\% + 0.82 \times 7.3\% = 10.6\%$. This estimate
 25 becomes 10.9% with flotation costs. The need for a flotation cost allowance is
 26 discussed later in my testimony.

27 Q. What is your estimate of PCPL's cost of equity using the ECAPM?

28 A. There have been countless empirical tests of the CAPM in the finance literature in
 29 order to determine to what extent security returns and betas are related in the
 30 manner predicted by the CAPM. This literature is summarized in Chapter 13 of
 31 my 1994 book, Regulatory Finance, and Chapter 6 of my most recent book, The
 32 New Regulatory Finance, both published by Public Utilities Report Inc. The
 33 results of the tests support the idea that beta is related to security returns, that the
 34 risk-return tradeoff is positive, and that the relationship is linear. The

contradictory finding is that the risk-return tradeoff is not as steeply sloped as the predicted CAPM. That is, empirical research has long shown that low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. A CAPM-based estimate of cost of capital underestimates the return required from low-beta securities and overstates the return required from high-beta securities, based on the empirical evidence. This is one of the most well-known results in finance, and it is displayed graphically below.

CAPM: Predicted vs Observed Returns



A number of variations on the original CAPM theory have been proposed to explain this finding. The ECAPM makes use of these empirical findings. The ECAPM estimates the cost of capital with the equation:

$$K = R_F + \alpha + \beta \times (MRP - \alpha)$$

where α is the "alpha" of the risk-return line, a constant, MRP is the market risk premium ($R_M - R_F$), and the other symbols are defined as usual. Inserting

the long-term risk-free rate as a proxy for the risk-free rate, an alpha in the range of 1% - 2%, and reasonable values of beta and the MRP in the above equation produces results that are indistinguishable from the following more tractable ECAPM expression:

$$K = R_F + 0.25 (R_M - R_F) + 0.75 \beta(R_M - R_F)$$

An alpha range of 1% - 2% is somewhat lower than that estimated empirically. The use of a lower value for alpha leads to a lower estimate of the cost of capital for low-beta stocks such as regulated utilities. This is because the use of a long-term risk-free rate rather than a short-term risk-free rate already incorporates some of the desired effect of using the ECAPM. That is, the long-term risk-free rate version of the CAPM has a higher intercept and a flatter slope than the short-term risk-free version which has been tested. This is also because the use of adjusted betas rather than the use of raw betas also incorporates some of the desired effect of using the ECAPM. Thus, it is reasonable to apply a conservative alpha adjustment.

Q. Is the use of the ECAPM consistent with the use of adjusted betas?

A. Yes, it is. Some have argued that the use of the ECAPM is inconsistent with the use of adjusted betas, such as those supplied by Value Line. This is because the reason for using the ECAPM is to allow for the tendency of betas to regress toward the mean value of 1.00 over time, and, since Value Line betas are already adjusted for such trend, an ECAPM analysis results in double-counting. This argument is erroneous. Fundamentally, the ECAPM is not an adjustment, increase or decrease, in beta. This is obvious from the fact that the observed

1 return on high beta securities is actually lower than that produced by the CAPM
2 estimate. The ECAPM is a formal recognition that the observed risk-return
3 tradeoff is flatter than predicted by the CAPM based on myriad empirical
4 evidence. The ECAPM and the use of adjusted betas comprised two separate
5 features of asset pricing. Even if a company's beta is estimated accurately, the
6 CAPM still understates the return for low-beta stocks. Even if the ECAPM is
7 used, the return for low-beta securities is understated if the betas are understated.
8 Referring back to the previous graph, the ECAPM is a return (vertical axis)
9 adjustment and not a beta (horizontal axis) adjustment. Both adjustments are
10 necessary. Moreover, the use of adjusted betas compensates for interest rate
11 sensitivity of utility stocks not captured by unadjusted betas, as explained in
12 Appendix A.

13 Appendix A contains a full discussion of the ECAPM, including its
14 theoretical and empirical underpinnings. In short, the following equation provides
15 a viable approximation to the observed relationship between risk and return, and
16 provides the following cost of equity capital estimate:

$$K = R_F + 0.25 (R_M - R_F) + 0.75 \beta (R_M - R_F)$$

18 Inserting 4.6% for the risk-free rate R_F , a MRP of 7.3% for $(R_M - R_F)$ and
19 a beta of 0.82 in the above equation, the ROE is 10.9% without flotation costs and
20 11.2% with flotation costs.

21 Q. Dr. Morin, please summarize your CAPM estimates.

22 A. The table below summarizes the common equity estimates obtained from my
23 CAPM studies. The average CAPM result is a rounded 11.1%.

<u>CAPM</u>	<u>% ROE</u>
CAPM plain	10.9%
Empirical CAPM	11.2%
AVERAGE	11.1%

1

2

2. HISTORICAL RISK PREMIUM

3 Q. Please describe your historical risk premium analysis of the electric utility
4 industry.

5 A. As a proxy for the risk premium applicable to the Company, I estimated the
6 historical risk premium for the electric utility industry with an annual time series
7 analysis applied to the industry as a whole, using *Moody's Electric Utility Index* as
8 an industry proxy. The analysis is depicted on Exhibit RAM-3. The risk
9 premium was estimated by computing the actual realized return on equity capital
10 for Moody's Index for each year, using the actual stock prices and dividends of
11 the index, and then subtracting the long-term government bond return for that
12 year.

13 As shown on Exhibit RAM-3, the average risk premium over the period
14 was 5.7% over historical long-term Treasury bond returns and 5.8% over long-
15 term Treasury bond yields. Given that the risk-free rate is 4.6%, and using the
16 historical estimate of 5.7%, the implied cost of equity for the average electric
17 utility from this particular method is $4.6\% + 5.7\% = 10.3\%$ without flotation costs
18 and 10.6% with flotation costs.

19 Q. Dr. Morin, are risk premium studies widely used?

20 A. Yes, they are. Risk Premium analyses are widely used by analysts, investors, and
21 expert witnesses. Most college-level corporate finance and/or investment

1 management texts including Investments by Bodie, Kane, and Marcus, McGraw-
2 Hill Irwin, 2002, which is a recommended textbook for CFA (Chartered Financial
3 Analyst) certification and examination, contain detailed conceptual and empirical
4 discussion of the risk premium approach. The latter is typically recommended as
5 one of the three leading methods of estimating the cost of capital. Professor
6 Brigham's best-selling corporate finance textbook (Financial Management:
7 Theory and Practice, 11th ed., South-Western, 2005), recommends the use of risk
8 premium studies, among others. Techniques of risk premium analysis are
9 widespread in investment community reports. Professional certified financial
10 analysts are certainly well versed in the use of this method.

11 Q. Are you concerned about the realism of the assumptions that underlie the historical
12 risk premium method?

13 A. No, I am not, for they are no more restrictive than the assumptions that underlie
14 the DCF model or the CAPM. While it is true that the method looks backward in
15 time and assumes that the risk premium is constant over time, these assumptions
16 are not necessarily restrictive. By employing returns realized over long time
17 periods rather than returns realized over more recent time periods, investor return
18 expectations and realizations converge. Realized returns can be substantially
19 different from prospective returns anticipated by investors, especially when
20 measured over short time periods. By ensuring that the risk premium study
21 encompasses the longest possible period for which data are available, short-run
22 periods during which investors earned a lower risk premium than they expected
23 are offset by short-run periods during which investors earned a higher risk
24 premium than they expected. Only over long time periods will investor return

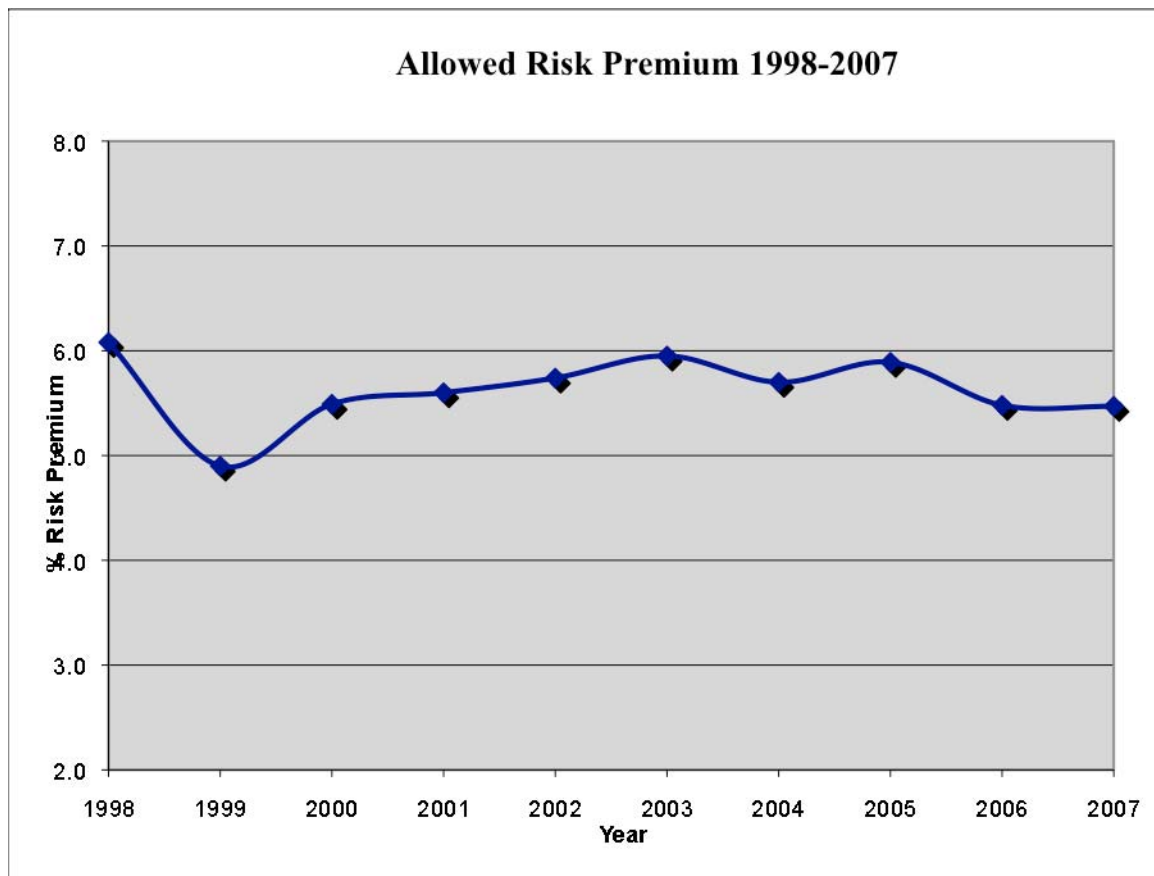
1 expectations and realizations converge, or else, investors would never invest any
2 money.

3 3. ALLOWED RISK PREMIUMS

4 Q. Please describe your analysis of allowed risk premiums in the electric utility
5 industry.

6 A. To estimate the Company's cost of common equity, I also examined the historical
7 risk premiums implied in the ROEs allowed by regulatory commissions for
8 electric utilities over the last decade relative to the contemporaneous level of the
9 long-term Treasury bond yield. This variation of the risk premium approach is
10 reasonable because allowed risk premiums are presumably based on the results of
11 market-based methodologies (DCF, Risk Premium, CAPM, *etc.*) presented to
12 regulators in rate hearings and on the actions of objective unbiased investors in a
13 competitive marketplace. Historical allowed ROE data are readily available over
14 long periods on a quarterly basis from SNL [formerly Regulatory Research
15 Associates ("RRA")] and easily verifiable from RRA publications and past
16 commission decision archives. The average ROE spread over long-term Treasury
17 yields was 5.6% for the 1999-2008 time period, as shown in the graph below. I
18 note that this estimate is nearly identical to the one obtained from the historical
19 risk premium study of the electric utility industry.

Given the current long-term Treasury bond yield of 4.6% and a risk premium of 5.6%, the implied allowed ROE for the average risk electric utility is 10.2%. No flotation cost adjustment is required here since the return figures are allowed book returns on common equity capital.



1

2

3 Q. Why did you rely on the last decade to conduct your allowed risk premium
4 analysis?

5 A. Because allowed returns already reflect investor expectations, that is, are forward-
6 looking in nature, the need for relying on long historical periods is minimized.
7 The last decade is a reasonable period of analysis in the case of allowed returns in
8 view of the stability of the inflation rate experienced over the last decade.

9 Q. Do investors take into account allowed returns in formulating their return
10 expectations?

11 A. Yes, they do. Investors do take into account returns granted by various regulators
12 in formulating their risk and return expectations, as evidenced by the availability

1 of commercial publications disseminating such data, including Value Line and
2 RRA. Allowed returns, while certainly not a precise indication of a particular
3 company's cost of equity capital, are an important determinant of investor growth
4 perceptions and investor expected returns.

5 Q. Please summarize your risk premium estimates.

6 A. The table below summarizes the ROE estimates obtained from the three risk
7 premium studies. The average risk premium result is 10.4%.

8	Risk Premium Method	ROE
9	Historical Risk Premium Electric	10.6%
10	Allowed Risk Premium	10.2%

11 **B. DCF ESTIMATES**

12 Q. Please describe the DCF approach to estimating the cost of equity capital.

13 A. According to DCF theory, the value of any security to an investor is the expected
14 discounted value of the future stream of dividends or other benefits. One widely
15 used method to measure these anticipated benefits in the case of a non-static
16 company is to examine the current dividend plus the increases in future dividend
17 payments expected by investors. This valuation process can be represented by the
18 following formula, which is the standard DCF model:

19
$$K_e = D_1/P_0 + g$$

20 where: K_e = investors' expected return on equity

21 D_1 = expected dividend at the end of the coming year

22 P_0 = current stock price

23 g = expected growth rate of dividends, earnings, stock price, book value

24 The standard DCF formula states that under certain assumptions, which

1 are described in the next paragraph, the equity investor's expected return, K_e , can
2 be viewed as the sum of an expected dividend yield, D_1/P , plus the expected
3 growth rate of future dividends, earnings, and book value, g . The returns
4 anticipated at a given stock price are not directly observable and must be
5 estimated from statistical information. The idea of the market value approach is
6 to infer ' K_e ' from the observed stock price, the observed dividend, and an estimate
7 of investors' expectations of future growth.

8 The assumptions underlying this valuation formulation are well known,
9 and are discussed in detail in Chapter 4 of my reference book, Regulatory
10 Finance, and Chapter 8 of my latest textbook, New Regulatory Finance. The
11 standard DCF model requires the following main assumptions: a constant average
12 growth trend for both dividends and earnings, a stable dividend payout policy, a
13 discount rate in excess of the expected growth rate, and a constant price-earnings
14 multiple, which implies that growth in price is synonymous with growth in
15 earnings and dividends. The standard DCF model also assumes that dividends are
16 paid at the end of each year when, in fact, dividend payments are normally made
17 on a quarterly basis.

18 Q. How did you estimate PCPL's cost of equity with the DCF model?

19 A. I applied the DCF model to two proxies for PCPL's energy delivery operations: a
20 group consisting of investment-grade dividend-paying electric distribution
21 utilities and a group consisting of those electric utilities that make up Moody's
22 Electric Utility Index. In addition, both groups were restricted to those companies
23 with at least 50% of their revenues from regulated operations.

1 In order to apply the DCF model, two components are required: the
2 expected dividend yield (D_1/P_0) and the expected long-term growth (g). The
3 expected dividend D_1 in the annual DCF model can be obtained by multiplying
4 the current indicated annual dividend rate by the growth factor $(1 + g)$.

5 From a conceptual viewpoint, the stock price to employ in calculating the
6 dividend yield is the current price of the security at the time of estimating the cost
7 of equity. The reason is that current stock price provides a better indication of
8 expected future prices than any other price in an efficient market. An efficient
9 market implies that prices adjust rapidly to the arrival of new information.
10 Therefore, the current price reflects the fundamental economic value of a security.
11 A considerable body of empirical evidence indicates that capital markets are
12 efficient with respect to a broad set of information. This evidence implies that
13 observed current prices represent the fundamental value of a security, and that a
14 cost of capital estimate should be based on current prices.

15 In implementing the DCF model, I have used the current dividend yields
16 reported in the latest edition of Value Line's VLIA software. Basing dividend
17 yields on average results from a large group of companies reduces the concern
18 that idiosyncrasies of individual company stock prices will result in an
19 unrepresentative dividend yield.

20 Q. How did you estimate the growth component of the DCF model?

21 A. The principal difficulty in calculating the required return by the DCF approach is
22 in ascertaining the growth rate that investors currently expect. Since no explicit
23 estimate of expected growth is observable, proxies must be employed.

1 As proxies for expected growth, I examined growth estimates developed
2 by professional analysts employed by large investment brokerage institutions.
3 Projected long-term growth rates actually used by institutional investors to
4 determine the desirability of investing in different securities influence investors'
5 growth anticipations. These forecasts are made by large reputable organizations,
6 and the data are readily available to investors and are representative of the
7 consensus view of investors. Because of the dominance of institutional investors
8 in investment management and security selection, and their influence on
9 individual investment decisions, analysts' growth forecasts influence investor
10 growth expectations and provide a sound basis for estimating the cost of equity
11 with the DCF model. Growth rate forecasts of analysts are available from
12 published investment newsletters and from systematic compilations of analysts'
13 forecasts, such as those tabulated by Zacks Investment Research Inc. ("Zacks"). I
14 used analysts' long-term earnings growth forecasts contained in Zacks as proxies
15 for investors' growth expectations in applying the DCF model. I also used Value
16 Line's earnings and dividend growth forecasts as an additional proxy. Unlike
17 earnings, there are no formal compilations of analysts' dividend growth forecasts,
18 owing to the scarcity of such forecasts.

19 Q. Why did you reject the use of historical growth rates in applying the DCF model
20 to utilities?

21 A. I have rejected historical growth rates as proxies for expected growth in the DCF
22 calculation because historical growth patterns are already incorporated in
23 analysts' growth forecasts that should be used in the DCF model, and are
24 therefore somewhat redundant.

1 Q. Did you consider any other method of estimating expected growth in the DCF
2 model?

3 A. Yes, I did. I considered using the so-called “sustainable growth” method, also
4 referred to as the “retention growth” method. According to this method, future
5 growth is estimated by multiplying the fraction of earnings expected to be
6 retained by the company, 'b', by the expected return on book equity, 'ROE'. That
7 is,

8
$$g = b \times \text{ROE}$$

9 where: g = expected growth rate in earnings/dividends

10 b = expected retention ratio

11 ROE = expected return on book equity

12 However, I do not generally subscribe to the growth results produced by
13 this particular method for several reasons. First, the sustainable method of
14 predicting growth is only accurate under the assumptions that the ROE is constant
15 over time and that no new common stock is issued by the company, or if so, it is
16 sold at book value. Second, and more importantly, the sustainable growth method
17 contains a logic trap: the method requires an estimate of ROE to be implemented.
18 But if the ROE input required by the model differs from the recommended return
19 on equity, a fundamental contradiction in logic follows. Third, the empirical
20 finance literature demonstrates that the sustainable growth method of determining
21 growth is not as significantly correlated to measures of value, such as stock prices
22 and price/earnings ratios, as analysts' growth forecasts⁶. I therefore placed no

⁶ See Vander Weide & Carleton, "Investor Growth Expectations: Analysts vs. History," Jrnl. of Portfolio Mgt., Spring 1988. Timme & Eiseman, "On the Use of Consensus Forecasts of Growth in the Constant Growth Model: The Case of Electric Utilities," Financial Mgt., Winter 1989.

1 reliance on this method.

2 Q. Please describe your first proxy group for the Company's electric distribution
3 business?

4 A. As a first proxy for the Company's energy distribution business, I examined a
5 group of investment-grade publicly-traded utilities designated as electricity
6 distribution utilities by S&P in its analysis of utility business risks. The original
7 group is shown on Pages 1 - 2 of Exhibit RAM-4, and includes electricity
8 distribution and natural gas distribution companies engaged in predominantly
9 monopolistic distribution activities. Foreign companies and companies below
10 investment-grade, that is, companies with a bond rating below BBB-, were
11 eliminated as well as those companies without Value Line coverage. Page 3 of
12 Exhibit RAM-4 narrows the group down to only include electricity distribution
13 operating utilities. The final sample of 11 companies is made up of the parent
14 company of these investment-grade operating electricity distribution companies
15 with at least 50% of their revenues from regulated operations, as shown on Page 4
16 of Exhibit RAM-4. The initial group was utilized earlier in connection with beta
17 estimates. The same group was retained for the DCF analysis.

18 Q. What DCF results did you obtain for the electricity distribution utilities group
19 using the Value Line growth forecasts?

20 A. As shown on Column 2 of Exhibit RAM-5 page 1, the average long-term earnings
21 growth forecast obtained from Value Line is 8.1% for this group. Combining this
22 growth rate with the average expected dividend yield of 4.1% shown in Column
23 3, produces an estimate of equity costs of 12.2% for the group, unadjusted for
24 flotation costs. Adding an allowance for flotation costs to the results of Column 4

1 brings the cost of equity estimate to 12.5%, shown in Column 5.

2 Page 2 of Exhibit RAM-5 displays the same analysis only this time using
3 Value Line's dividend growth forecasts instead of earnings growth forecasts. The
4 average long-term dividend growth forecast obtained from Value Line is 6.9% for
5 this group. Combining this growth rate with the average expected dividend yield
6 of 4.1% shown in Column 3, produces an estimate of equity costs of 10.3% for
7 the group, unadjusted for flotation costs. Adding an allowance for flotation costs
8 to the results of Column 4 brings the cost of equity estimate to 10.5%, shown in
9 Column 5. Removing Ameren from the group because of the unavailability of a
10 dividend growth forecast, the average cost of equity estimate for the group is
11 11.0%. The average of the two estimates derived from earnings growth, 12.5%,
12 and dividend growth, 11.0%, is 11.7%.

13 Q. What DCF results did you obtain for the electricity distribution utilities group
14 using the analyst's consensus growth forecast?

15 A. From the original sample of eleven companies shown on page 1 of Exhibit RAM-
16 6, Energy East was eliminated as no analysts' growth forecasts was available
17 from Zacks. The DCF analysis for the remaining ten companies is shown on page
18 2 of Exhibit RAM-6. Using the consensus analysts' earnings growth forecast
19 published by Zacks of 8.8% instead of the Value Line forecast, the cost of equity
20 for the group is 12.9%. Allowance for flotation costs brings the cost of equity
21 estimate to 13.1%. Eliminating the outlying PPL Corp. estimate of 19.6% and in
22 order to palliate the influence of the two companies with high growth estimates
23 (Exelon and Public Service Enterprise), the median estimate of 11.2% is a more
24 reasonable estimate.

1 Q. What DCF results did you obtain for Moody's electric utilities group using the
2 Value Line growth forecasts?

3 A. Page 1 of Exhibit RAM-7 displays the electric utilities that make up Moody's
4 Electric Utility Index. No growth forecast was available for Duke Energy, and
5 that company was therefore eliminated from the group. The DCF analysis is
6 shown on page 2 of Exhibit RAM-7. As shown on Column 2 of page 2 of
7 Exhibit RAM-7, the average long-term growth forecast obtained from Value Line
8 is 6.8% for this group. Coupling this growth rate with the average expected
9 dividend yield of 4.4% shown in Column 3 produces an estimate of equity costs
10 of 11.1% for the group. Allowance for flotation costs brings the cost of equity
11 estimate to 11.4%.

12 Eliminating the companies with less than 50% of their revenues from
13 regulated electricity operations, the average DCF result for the remaining fourteen
14 companies is 11.1%, as shown on page 3 of Exhibit RAM-7.

15 Page 4 of Exhibit RAM-7 displays the same analysis only this time using
16 Value Line's dividend growth forecasts instead of earnings growth forecasts. The
17 average long-term dividend growth forecast obtained from Value Line is 5.0% for
18 this group. Combining this growth rate with the average expected dividend yield
19 of 4.3% shown in Column 3, produces an estimate of equity costs of 9.2% for the
20 group, unadjusted for flotation costs. Adding an allowance for flotation costs to
21 the results of Column 4 brings the cost of equity estimate to 9.4%, shown in
22 Column 5. The average of the two estimates derived from earnings growth,
23 11.1%, and dividend growth, 9.4%, is 10.3%.

1 Q. What DCF results did you obtain for the Moody's electric utilities group using
2 analysts' growth forecasts?

3 A. The DCF analysis is displayed on Pages 1 and 2 of Exhibit RAM-8. Page 1 shows
4 the Moody's companies sample, along with the dividend yield and growth data.
5 No growth projections were available for CH Energy and Energy East, and these
6 two companies were therefore eliminated from the group. Page 2 displays the
7 actual DCF analysis for the remaining 18 companies. Using the analysts'
8 earnings growth forecast of 8.0% from Zacks instead of the Value Line growth
9 forecast, the cost of equity for the Moody's group is 12.4%. Allowance for
10 flotation costs brings the cost of equity estimate to 12.6%.

11 As shown on page 3 of Exhibit RAM-8, eliminating utility companies with
12 less than 50% of their revenues from utility operations from the Moody's group,
13 the average estimate for the group is 12.4%. In order to palliate the influence of
14 the companies with high growth estimates, the median estimate of 11.3% is a
15 more reasonable estimate.

16 Q. Please summarize your DCF estimates.

17 A. The table below summarizes the DCF estimates. The mean DCF result is 11.1%.

DCF STUDY	ROE
Electricity Distribution Utilities Value Line Growth	11.7%
Electricity Distribution Utilities Zacks Growth	11.2%
Moody's Electric Utilities Value Line Growth	10.3%
Moody's Electric Utilities Zacks Growth	11.3%

18

19 Q. Dr. Morin, please now turn to the need for a flotation cost allowance.

20 A. All the market-based estimates reported above include an adjustment for flotation
21 costs. The simple fact of the matter is that common equity capital is not free.

1 Flotation costs associated with stock issues are exactly like the flotation costs
2 associated with bonds and preferred stocks. Flotation costs are incurred; they are
3 not expensed at the time of issue and, therefore, must be recovered via a rate of
4 return adjustment. This treatment is done routinely for bond and preferred stock
5 issues by most regulatory commissions. Clearly, the common equity capital
6 accumulated by the Company is not cost-free. The flotation cost allowance to the
7 cost of common equity capital is discussed and applied in most corporate finance
8 textbooks; it is unreasonable to ignore the need for such an adjustment.

9 Flotation costs are very similar to the closing costs on a home mortgage.
10 In the case of issues of new equity, flotation costs represent the discounts that
11 must be provided to place the new securities. Flotation costs have a direct and an
12 indirect component. The direct component is the compensation to the security
13 underwriter for his marketing/consulting services, for the risks involved in
14 distributing the issue, and for any operating expenses associated with the issue
15 (printing, legal, prospectus, etc.). The indirect component represents the
16 downward pressure on the stock price as a result of the increased supply of stock
17 from the new issue. The latter component is frequently referred to as "market
18 pressure."

19 Investors must be compensated for flotation costs on an ongoing basis to
20 the extent that such costs have not been expensed in the past, and therefore the
21 adjustment must continue for the entire time that these initial funds are retained in
22 the firm. Appendix B to my testimony discusses flotation costs in detail, and
23 shows: (1) why it is necessary to apply an allowance of 5% to the dividend yield
24 component of equity cost by dividing that yield by 0.95 (100% - 5%) to obtain the

1 fair return on equity capital; (2) why the flotation adjustment is permanently
2 required to avoid confiscation even if no further stock issues are contemplated;
3 and (3) that flotation costs are only recovered if the rate of return is applied to
4 total equity, including retained earnings, in all future years.

5 By analogy, in the case of a bond issue, flotation costs are not expensed
6 but are amortized over the life of the bond, and the annual amortization charge is
7 embedded in the cost of service. The flotation adjustment is also analogous to the
8 process of depreciation, which allows the recovery of funds invested in utility
9 plant. The recovery of bond flotation expense continues year after year,
10 irrespective of whether the Company issues new debt capital in the future, until
11 recovery is complete, in the same way that the recovery of past investments in
12 plant and equipment through depreciation allowances continues in the future even
13 if no new construction is contemplated. In the case of common stock that has no
14 finite life, flotation costs are not amortized. Thus, the recovery of flotation cost
15 requires an upward adjustment to the allowed return on equity.

16 A simple example will illustrate the concept. A stock is sold for \$100, and
17 investors require a 10% return, that is, \$10 of earnings. But if flotation costs are
18 5%, the Company nets \$95 from the issue, and its common equity account is
19 credited by \$95. In order to generate the same \$10 of earnings to the
20 shareholders, from a reduced equity base, it is clear that a return in excess of 10%
21 must be allowed on this reduced equity base, here 10.52%.

22 According to the empirical finance literature discussed in Appendix B,
23 total flotation costs amount to 4% for the direct component and 1% for the market
24 pressure component, for a total of 5% of gross proceeds. This in turn amounts to

1 approximately 30 basis points, depending on the magnitude of the dividend yield
2 component. To illustrate, dividing the average expected dividend yield of
3 approximately 5.0% for utility stocks by 0.95 yields 5.3%, which is 30 basis
4 points higher.

5 Sometimes, the argument is made that flotation costs are real and should
6 be recognized in calculating the fair return on equity, but only at the time when
7 the expenses are incurred. In other words, the flotation cost allowance should not
8 continue indefinitely, but should be made in the year in which the sale of
9 securities occurs, with no need for continuing compensation in future years. This
10 argument is valid only if the Company has already been compensated for these
11 costs. If not, the argument is without merit. My own recommendation is that
12 investors be compensated for flotation costs on an on-going basis rather than
13 through expensing and that the flotation cost adjustment continue for the entire
14 time that these initial funds are retained in the firm.

15 There are several sources of equity capital available to a firm including:
16 common equity issues, conversions of convertible preferred stock, dividend
17 reinvestment plan, employees' savings plan, warrants, and stock dividend
18 programs. Each item carries its own set of administrative costs and flotation cost
19 components, including discounts, commissions, corporate expenses, offering
20 spread, and market pressure. The flotation cost allowance is a composite factor
21 that reflects the historical mix of sources of equity. The allowance factor is a
22 build-up of historical flotation cost adjustments associated and traceable to each
23 component of equity at its source. It is impractical and prohibitively costly to
24 start from the inception of a company and determine the source of all present

1 equity. A practical solution is to identify general categories and assign one factor
2 to each category. My recommended flotation cost allowance is a weighted
3 average cost factor designed to capture the average cost of various equity vintages
4 and types of equity capital raised by the Company.

5 Q. Is a flotation cost adjustment required for an operating subsidiary like PCPL that
6 does not trade publicly?

7 A. Yes, it is. It is sometimes alleged that a flotation cost allowance is inappropriate
8 if the utility is a subsidiary whose equity capital is obtained from its parent, in this
9 case, PCPL Group. This objection is unfounded since the parent-subsidiary
10 relationship does not eliminate the costs of a new issue, but merely transfers them
11 to the parent. It would be unfair and discriminatory to subject parent shareholders
12 to dilution while individual shareholders are absolved from such dilution. Fair
13 treatment must consider that, if the utility-subsidiary had gone to the capital
14 markets directly, flotation costs would have been incurred.

15 **III. SUMMARY OF COST OF EQUITY RECOMMENDATION**

16 Q. Please summarize your results and recommendation.

17 A. To arrive at my final recommendation, I performed four risk premium analyses.
18 For the first two risk premium studies, I applied the CAPM and an empirical
19 approximation of the CAPM using current market data. The other two risk
20 premium analyses were performed on historical and allowed risk premium data
21 from electric utility industry aggregate data. I also performed DCF analyses on
22 two surrogates for PCPL: a group of investment-grade electricity distribution
23 utilities and a group representative of the electric utility industry, namely,
24 Moody's Electric Utility Index. The results from all the various tests are

1 summarized in the table below

2	METHODOLOGY	ROE
	CAPM	10.9%
	Empirical CAPM	11.2%
	Historical Risk Premium Elec Utility Industry	10.6%
	Allowed Risk Premium	10.2%
	DCF S&P Elec Distribution Utilities Value Line Growth	11.7%
	DCF S&P Elec Distribution Utilities Zacks Growth	11.2%
	DCF Moody's Elec Utilities Value Line Growth	10.3%
	DCF Moody's Elec Utilities Zacks Growth	11.3%

3

4 The average result from the table is 10.9%. From a broader
5 methodological standpoint, the average result from the three principal
6 methodologies is also 10.9%, as shown below:

7	CAPM	11.1%
8	Risk Premium	10.4%
9	DCF	<u>11.1%</u>
10	AVERAGE	10.9%

11 The overall average result is 10.9% for the average electricity distribution
12 utility. I note that all three methods, including DCF are equally weighted, and
13 that the DCF results are based on four different tests.

14 Q. Did you adjust these results to account for the fact that PCPL's risk profile differs
15 from the average electric utility?

16 A. No, I did not. In my view, PCPL's lower business risk on account of its status as
17 a pure "wires" utility unencumbered with the riskier power production function
18 and its stronger than average common equity ratio offset its higher investment risk
19 on account of its very small size.

20

1 Q. Please comment on PCPL's size related risks.

2 A. Because of its very small, PCPL's investment risks are higher than those of the
3 industry. PCPL possesses small revenue and asset bases, both in absolute terms
4 and relative to other utilities. Investment risk increases as company size
5 diminishes, all else remaining constant.

6 As the empirical finance literature has clearly demonstrated, small
7 companies have very different returns than large ones and on average those
8 returns have been higher. The greater risk of small stocks does not fully account
9 for their higher returns over many historical periods. The average small stock
10 premium is very significant over the average stock, more than could be expected
11 by risk differences alone, suggesting that the cost of equity for small stocks is
12 considerably larger than for large capitalization stocks. In addition to earning the
13 highest average rates of return, small stocks also have the highest volatility, as
14 measured by the standard deviation of returns.

15 Q. Dr. Morin, what is your final conclusion regarding PCPL's cost of common equity
16 capital?

17 A. Based on the results of all my analyses, the application of my professional
18 judgment, and the risk circumstances of PCPL, it is my opinion that a just and
19 reasonable return on the market value of the common equity capital of PCPL's
20 energy distribution operations in the state of Pennsylvania is 10.9%.

21 Q. Dr. Morin, what capital structure assumption underlies your recommended return
22 on PCPL's common equity capital?

23 A. My recommended ROE for PCPL is predicated on the adoption of a test year
24 capital structure consisting of approximately 52% common equity capital.

- 1 Q. Is there a relationship between financial risk and the authorized ROE?
- 2 A. There certainly is. A low authorized ROE increases the likelihood the utility will
- 3 have to rely increasingly on debt financing for its capital needs. This creates the
- 4 specter of a spiraling cycle that further increases risks to both equity and debt
- 5 investors; the resulting increase in financing costs is ultimately borne by the
- 6 utility's customers through higher capital costs and rates of returns.
- 7 Q. Is PCPL's financial risk impacted by the authorized ROE?
- 8 A. Yes, it is. A low ROE increases the likelihood that PCPL will have to rely on debt
- 9 financing for its capital needs. As the Company relies more on debt financing, its
- 10 capital structure becomes more leveraged. Since debt payments are a fixed
- 11 financial obligation to the utility, this decreases net income. If, instead, the
- 12 Company attempts to maintain its capitalization ratios by issuing more stock,
- 13 lower operating income and more shares outstanding mean less income per share
- 14 available for dividend growth. In either case, equity investors face greater
- 15 uncertainty about the future dividend potential of the firm. As a result, the
- 16 Company's equity becomes a riskier investment. The risk of default on the
- 17 Company's bonds also increases, making the utility's debt a riskier investment.
- 18 This increases the cost to the utility from both debt and equity financing and]
- 19 increases the possibility the Company will not have access to the capital markets
- 20 for its outside financing needs, or if so, at prohibitive costs.
- 21 Q. Finally, Dr. Morin, if capital market conditions change significantly between the
- 22 date of filing your prepared testimony and the date your oral testimony is
- 23 presented, would this cause you to revise your estimated cost of equity?
- 24 A. Yes. Interest rates and security prices do change over time, and risk premiums

1 change also, although much more sluggishly. If substantial changes were to occur
2 between the filing date and the time my oral testimony is presented, I will update
3 my testimony accordingly.

4 Q. Does this conclude your direct testimony?

5 A. Yes, it does.

**PIKE COUNTY LIGHT & POWER COMPANY
GAS RATE PANEL**

1 Q. Would the members of the Rate Panel please state their names and business
2 address?

3 A. William Atzl, Yan Flishenbaum and Cheryl Ruggiero, 4 Irving Place, New York,
4 New York 10003.

5 Q. By whom are you employed, in what capacity, and what are your professional
6 backgrounds and qualifications?

7 A. (**Atzl**) I will act as Chairman of the Panel. We all are employed by Consolidated
8 Edison Company of New York, Inc. ("Con Edison"). I am Director – O&R Rates
9 in the Con Edison Rate Engineering Department. In this position, I manage the
10 rate related activities for Orange and Rockland Utilities, Inc. ("Orange and
11 Rockland") and its subsidiaries Pike County Light & Power Company ("Pike" or
12 "the Company") and Rockland Electric Company. In 1983, I graduated from the
13 State University of New York at Stony Brook with a Bachelor of Engineering
14 degree in Mechanical Engineering. In 1989, I graduated from Pace University,
15 White Plains, New York with a Master of Business Administration degree in
16 Management Information Systems. I am a Licensed Professional Engineer in the
17 State of New York. My first employment was with Long Island Lighting
18 Company in 1983 where I held the position of Assistant Engineer in the New
19 Business Department. In 1984, I joined Orange and Rockland as a Commercial
20 and Industrial Representative in the Commercial Operations Department. At
21 Orange and Rockland, I also held the positions of Commercial and Industrial
22 Engineer, Program Administrator - Demand-Side Management, Manager -
23 Demand-Side Management Operations, Manager - Energy Services and Pricing,

GAS RATE PANEL

1 and Manager – Regulatory Affairs. In October 1999, I joined Con Edison and
2 held the position Department Manager – Electric and Gas Rate Design – O&R
3 prior to my present position. I have testified in numerous regulatory proceedings
4 before the Pennsylvania Public Utility Commission (“Commission”), New York
5 Public Service Commission (“NYPSC”) and New Jersey Board of Public
6 Utilities.

7 **(Flishenbaum)** I am a Senior Analyst in the Rate Engineering Department of Con
8 Edison. My background is as follows: I received a Bachelor of Business
9 Administration Degree in Economics from Pace University in 2001 and a Master
10 of Business Administration Degree in Finance and Economics from New York
11 University in 2008. In 2001, I began my employment with Con Edison in the Cost
12 Analysis Area of the Rate Engineering Department. In 2003, I was promoted to
13 Analyst, mainly involved in the development of the costing methodologies related
14 to unbundling. I was promoted to Senior Analyst in 2005, responsible for
15 developing the Company’s cost-of-service models. I have previously testified
16 before the NYPSC in Con Edison’s gas rate case, Case 06-G-1332.

17 **(Ruggiero)** I am a Senior Analyst in the Rate Engineering Department. I received
18 a Bachelor of Science Degree in Electrical Engineering from Polytechnic
19 University in June 2000. I am currently pursuing a Master of Business
20 Administration Degree in Finance from Baruch College. In 2000, I began my
21 employment with Con Edison as a Management Intern with rotational
22 assignments in Electric Operations, Engineering Services, and Gas Operations. In
23 July 2001, I accepted a position as Associate Engineer - A in Distribution

GAS RATE PANEL

1 Engineering. I have been in my current position since November 2005 and have
2 not testified in any prior proceedings.

3 Q. What is the purpose of the Panel's testimony?

4 A. Our testimony presents:

- 5 (1) the Company's Gas Embedded Cost of Service ("ECOS") study;
6 (2) the Company's gas revenue forecasts;
7 (3) the Company's proposal for revenue allocation and rate design;
8 (4) the impact of the proposed rate changes on customers' bills; and
9 (5) other tariff changes.

10 Q. Please summarize your testimony.

11 A. First, the Panel presents the Company's ECOS study for calendar year 2007
12 which:

- 13 • functionalizes and classifies various gas system costs to their operating
14 functions;
15 • allocates these functionalized costs to the customer classes;
16 • shows a total system rate-of-return of -2.42%, a Total Residential rate-of-
17 return of -3.59%, and a Total Commercial rate-of-return of 7.46%.
18 • demonstrates each ECOS study class's surplus or deficiency based on the
19 application of a $\pm 10\%$ tolerance band around the calculated total system
20 rate-of-return.

GAS RATE PANEL

1 Second, the Gas Revenue Forecast section describes the forecast of future test
2 year gas revenues.

3 Third, the Gas Rate Design section of the testimony describes (1) the Company's
4 proposal to realign revenues to address class surpluses and deficiencies identified
5 in the ECOS study, (2) the allocation of the proposed revenue increase to the
6 realigned class revenues, and (3) the determination of class-specific percentage
7 increases to existing rates.

8 Fourth, the Customer Bill Impacts section describes exhibits that show customer
9 bill impacts at various consumption levels.

10 Fifth, the Tariff Changes section discusses the Company's proposal to implement
11 reconnection and late payment charges.

12 Q. Is the Panel sponsoring any exhibits?

13 A. Yes, we are sponsoring the following exhibits:

14 (1) Exhibit G-6 – Schedules 3-4 – Gas Revenues;

15 (2) Exhibit G-7 – Embedded Cost of Service Study; and

16 (3) Exhibit G-8 – Schedules 1-3 – Gas Present and Proposed Rate Design.

17 Q. How is the Panel's testimony organized?

18 A. The testimony is divided into the following five sections: (1) ECOS Study, (2)
19 Gas Revenue Forecast, (3) Gas Rate Design, (4) Customer Bill Impacts, and (5)
20 Tariff Changes.

21 **ECOS STUDY**

22 Q. Please describe the ECOS study.

GAS RATE PANEL

1 A. The ECOS study, which is contained in a document entitled “PIKE COUNTY
2 LIGHT AND POWER COMPANY – COST-OF-SERVICE STUDY – GAS
3 DEPARTMENT - YEAR 2007”, begins with explanatory notes detailing sources
4 of data and methods used in the preparation of the ECOS study followed by seven
5 tables of cost data.

6 MARK FOR IDENTIFICATION AS EXHIBIT G-7

7 Q. What time period does the ECOS study cover?

8 A. It covers Pike’s gas operations for the calendar year 2007.

9 Q. What gas revenues are reflected in the ECOS study?

10 A. The study uses actual 2007 delivery gas revenues.

11 Q. What customer classes are analyzed in the ECOS study?

12 A. The ECOS study analyzes Pike’s two classes: (1) Residential Service and
13 Residential Space Heating (“Total Residential”) and (2) General Service and Non-
14 Residential Space Heating (“Total Commercial”). A description of the type of
15 customers served under each service classification is set forth on page eight of the
16 ECOS explanatory notes.

17 Q. How are the results of the ECOS study expressed?

18 A. The results of the ECOS study are expressed as total system and class-by-class
19 rates of return.

20 Q. What is the total system rate of return shown in the ECOS study?

21 A. The total system rate of return shown on Table 1, Page 1, Column (1), Line 15 of
22 the ECOS study is -2.42%.

23 Q. What are the class rates of return shown in the ECOS study, Exhibit G-7?

GAS RATE PANEL

1 A. The following class rates of return are shown on Table 1, Page 1, Line 15 of the
2 ECOS study:

3 Total Residential: -3.59%

4 Total Commercial: 7.46%

5 Q. Has the Company employed “tolerance bands” around the total system rate of
6 return in developing class revenue responsibilities?

7 A. Yes. Class revenue responsibility has been measured with respect to a $\pm 10\%$
8 tolerance band around the total system average rate of return. Classes would not
9 be considered “surplus” or “deficient” if the class ECOS rate of return falls within
10 this band. Classes that fall outside this range would be either surplus or deficient
11 by the amount necessary to bring the realized return to the upper or lower band.

12 Q. Based on the application of a $\pm 10\%$ tolerance band around the calculated total
13 system rate of return of -2.42%, what are the ECOS study class surpluses and
14 deficiencies?

15 A. Total Residential service class shows a revenue deficiency of approximately
16 \$27,000. Total Commercial service class shows a revenue surplus of
17 approximately \$22,000.

18 Q. What is the significance of the Total Residential service class deficiency?

19 A. The deficiency is the amount of revenue increase, at current rates, required to
20 bring the Total Residential service class’s return to the lower level of the
21 tolerance band around the total system rate of return.

22 Q. Please describe what is shown on Table 1A, which is the last page of Exhibit G-7.

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1 A. Due to the application of a $\pm 10\%$ tolerance band around the total system rate of
2 return, the total of the ECOS surplus and deficiency is a net system deficiency. In
3 order that the ECOS study indications are revenue neutral to the Company, and in
4 order that no class rate-of-return is below the lower level of the tolerance band,
5 Table 1A adjusts the deficiency of the Total Residential class so that the amount
6 of the surplus matches that of the deficiency. The result is a deficiency of
7 \$22,488 for the Total Residential Class and a surplus of \$22,488 for the Total
8 Commercial class. These adjusted surplus and deficiency indications are used in
9 revenue allocation as described later in this testimony.

10 Q. Does the ECOS study contain an analysis of customer costs by class of service?

11 A. Yes. Please refer to Table 6, Page 1, Line 14 of the ECOS study. The monthly
12 customer costs by class for the cost study's test period are as follows:

13 Total Residential: \$20.45

14 Total Commercial: \$31.68

15 Q. What do customer costs include?

16 A. Customer costs include distribution customer component, services, meter and
17 meter installations, customer installations, customer accounting, uncollectibles
18 and customer service.

19 Q. Please describe the methodology used in developing the ECOS study.

20 A. There are two main steps in the preparation of the ECOS study: (1)
21 functionalization and classification of costs to operating functions, such as
22 distribution, customer accounting and customer service (with further division into

GAS RATE PANEL

1 sub-functions such as distribution-demand/customer components), and (2)
2 allocation of these functionalized costs to customer classes.

3 Q. Please describe the functionalization and classification step.

4 A. The functionalization and classification step assigns the broad accounting-based
5 cost categories to the more detailed categories used in the ECOS study. This
6 breakdown is required, for example, to differentiate distribution-demand related
7 costs from distribution-customer related costs. During the process of
8 functionalization, all costs are classified as being demand-related, commodity-
9 related, and customer-related. Demand-related costs are fixed costs created by the
10 loads placed on the various components of the gas system. Commodity-related
11 costs are variable costs caused by the total quantities of gas delivered during the
12 year. Customer-related costs are fixed costs, which are caused by the presence of
13 customers connected to the system, regardless of their usage. There are no
14 commodity-related costs in this study.

15 Q. Please describe the allocation step.

16 A. The allocation step allocates the functionalized and classified costs to the
17 customer classes based on the appropriate demand, customer or revenue
18 allocation factors, which are shown on Table 7 of the ECOS study.

GAS REVENUE FORECAST

19
20 Q. Please describe the method used to forecast the future test year gas revenues for
21 Service Classification Nos. 1 and 2, as shown in detail on Exhibit G-6, Schedule
22 4.

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1 A. Gas revenues on Exhibit G-6, Schedule 4, reflect billed and unbilled revenue, Gas
2 Cost Rate (“GCR”) revenue, and revenue derived from the State Tax Adjustment
3 Surcharge (“STAS”) for the twelve months ending March 31, 2009. In
4 forecasting gas revenues, the forecast of billing determinants (i.e., Ccf sales and
5 bills) by customer class provided by the Accounting Panel was used. The billing
6 determinants for SC No. 2 were distributed to the appropriate pricing blocks
7 based on such distributions for the twelve months ended March 31, 2008. The
8 resulting SC No. 1 and SC No. 2 block-by-block billing determinants were then
9 priced at rates in effect at the time of this filing (“current rates”). Unbilled
10 revenues were forecast using unbilled sales provided by the Accounting Panel and
11 the average rates developed from the billed forecast. GCR revenues were
12 determined based on the current GCR for the period April 2008 through August
13 2008. For the period September 2008 through March 2009, GCR revenues were
14 determined based on the GCR proposed by the Company in its July 2, 2008
15 preliminary GCR filing. Revenues derived from the STAS at its current level
16 were then added to the above base rate and GCR revenues.

GAS RATE DESIGN

18 Q. What is the basis for the revenue increase used in the proposed rate design?

19 A. The proposed revenue increase of \$445,900 was provided by the Accounting
20 Panel.

21 Q. Please describe the first step in allocating the increased base rate revenue among
22 Pike’s Service Classes.

GAS RATE PANEL

1 A. The Commission's March 10, 1970 Order establishing STAS requires the
2 Company to zero out its STAS in a base rate proceeding and transfer STAS
3 recovery to base rates. Pike's current STAS is a credit of \$439 annually.
4 Therefore, a credit of \$439 has been transferred from the STAS to base rates.
5 This has decreased the total incremental revenue requirement to \$424,461.

6 Q. Please describe the next step in the revenue allocation process.

7 A. Rate Year Base Rate Revenues at the current rate level for SC No. 1 and SC No. 2
8 were realigned to eliminate the deficiency and surplus indications from Table 1A
9 of the ECOS study. This is accomplished by adding \$22,488 to SC No. 1
10 revenues and subtracting \$22,488 from SC No. 2 revenues.

11 Q. Please describe how Pike proposes to allocate the revenue increase between SC
12 No. 1 and SC No. 2.

13 A. The revenue increase was allocated between SC No. 1 and SC No. 2 in proportion
14 to the relative contribution made by each class to the realigned total rate year base
15 rate revenues.

16 Q. How is the proposed revenue increase for each class applied in determining the
17 Company's proposed base rates?

18 A. First, for each class, the increases, determined as set forth above, were divided by
19 the rate year base rate revenues at current rates to establish percentages by which
20 base rates for each class would be increased.

21 Q. How were the SC No. 1 rates determined?

22 A. For SC No. 1, the service and commodity charges were increased on a uniform
23 percentage basis by the SC No. 1 percentage determined as set forth previously.

GAS RATE PANEL

1 Q. How were the SC No. 2 rates determined?

2 A. The first step was to increase the service charge for SC No. 2 to a level that better
3 reflects the Company's cost to provide service. This charge is currently \$5.00 per
4 month. As previously noted, the ECOS study shows an embedded customer cost
5 of \$31.68 per month for SC No. 2 customers and \$20.45 per month for SC No. 1
6 customers. Based on these ECOS results, the Company's service charges should
7 be increased. In addition, the relationship between the SC No. 2 and SC No. 1
8 service charges should better reflect the approximate 1.5 to 1 ratio resulting from
9 the ECOS study. In the SC No. 1 rate design process described previously, the
10 service charge was increased from \$5.00 to \$6.29. To achieve the 1.5 to 1 ratio of
11 SC No. 2 to SC No. 1 service charges, we are proposing to increase the SC No. 2
12 service charge from \$5.00 to \$9.43, a level 1.5 times the SC No. 1 service charge.
13 This increase establishes the appropriate relationship between service charges and
14 moves closer to matching the service charges with the corresponding costs of
15 service while limiting the rate impacts of the changes. After adjusting the SC No.
16 2 share of the overall revenue increase for the increase in the service charge, the
17 remaining SC No. 2 increase was applied to commodity charges on a uniform
18 percentage basis.

19

CUSTOMER BILL IMPACTS

20
21 Q. Please describe the schedules in Exhibit G-8.

22 A. Schedule 1 in Exhibit G-8 is a summary of the present and proposed rates for
23 Pike's gas service classifications. Schedule 2 provides a comparison of monthly

GAS RATE PANEL

customer bills under the present and proposed rates at various consumption levels for SC Nos. 1 and 2 customers. Schedule 3, Page 1 of 2 contains information on the number of customers served and the distribution of base rate and total revenues by tariff subdivision at currently effective rates. Schedule 3, Page 2 of 2 sets forth certain information required of Pike by Section 53.52 of the Commission's regulations, 52 Pa. Code § 53.52. Specifically, it shows:

- a) a calculation of the number of customers, by tariff subdivision, whose bills will be increased;
- b) a calculation of the total increases, in dollars, by tariff subdivision, projected on an annual basis;
- c) a calculation of the number of customers, by tariff subdivision, whose bills will be decreased; and
- d) a calculation of the total decreases, in dollars, by tariff subdivision, projected to an annual basis.

Note that the Company's rate design methodology will cause the bills of all of Pike's gas customers to increase.

TARIFF CHANGES

Q. Have you proposed any changes in the Company's service fees?

A. Yes. We have proposed a change to the reconnection charge and the establishment of a late payment charge.

Q. Please describe the reconnection charge.

A. When notified that a previously disconnected gas service is ready for reconnection, the Company sends a Gas Service Technician to the premises to

GAS RATE PANEL

1 reconnect the service. In addition to turning on the customer's gas service at the
2 disconnect valve, this task includes a fuel line test, regulator inspection, leak test,
3 line purge, re-light of all pilots and test for carbon monoxide. Currently, General
4 Information Section No. 15.1 of Pike's electric tariff allows the Company to
5 charge a "reasonable reconnection fee" but does not define the amount. In the
6 interest of consistency, the Company proposes to set a specific reconnection
7 charge of \$27.00.

8 Q. How was the reconnection charge determined?

9 A. We are proposing a uniform reconnection charge for both the Company's gas and
10 electric services. Since the vast majority of Pike's reconnections of service are
11 for electric service, the \$27.00 charge was determined based on the costs
12 associated with a reconnection of electric service. Applicable man-hour rates
13 were applied to the time associated with completing a reconnection of electric
14 service. The average time required for a reconnection of electric service is 20
15 minutes: 5 minutes of travel time and 15 minutes spent at the customer's
16 premises. This required time is multiplied by the applicable hourly rate for a 3rd
17 Class Meter Technician. The hourly rate during normal work hours is \$82.35 per
18 hour. The cost for 20 minutes of a 3rd Class Meter Technician's time is \$27.45.
19 To establish the reconnection charge, this figure was rounded. It should be noted
20 that the time period spent on a customer's premises for a gas reconnection is
21 approximately 30 minutes due to the additional tasks required for the gas
22 reconnection.

23 Q. Please describe the late payment charge.

GAS RATE PANEL

1 A. In accordance with Sections 56.21 and 56.22 of the Commission's regulations, 52
2 Pa. Code § 56.21 and § 56.22, the majority of Pennsylvania utilities collect a late
3 payment charge for payments received more than five days after the due date of
4 the customer bill. The regulations also state that the maximum interest rate
5 should be set to no more than 1.5% per month on the overdue balance of the bill.
6 The Company proposes to establish a late payment charge of 1.5% to be applied
7 in accordance with these regulations.

8 Q. Does this conclude your testimony?

9 A. Yes, it does.

Pike County Light And Power Company
Index of Schedules
Balance Sheet and Supporting Schedules, Income Statement,
and Joint Operating Agreement Charges for the Test Year

Exhibit G-1

<u>Schedule</u>	<u>Title of Schedule</u>	<u>Witness</u>
(1)	Balance Sheet	Accounting Panel
(2)	Detail of Gas and Electric Plant in Service and associated Depreciation Reserves	Accounting Panel
(3)	Income Statement for the Test Year, the Twelve Month Period Ending March 31, 2008	Accounting Panel
(4)	Income Statement-Gas for the Twelve Month Period Ended March 31, 2007 and March 31, 2008	Accounting Panel
(5)	Joint Operating Agreement Charges for the Test Year, the Twelve Month Period Ending March 31, 2008	Accounting Panel

Pike County Light And Power Company
Balance Sheet
As of March 31, 2008 And 2007

Exhibit G-1
Schedule 1
Page 1 of 2

ASSETS AND OTHER DEBITS

	March 31, 2008	March 31, 2007
<u>Utility Plant</u>		
Electric Plant in Service	\$ 12,465,625	\$ 11,952,027
Gas Plant in Service	1,725,933	1,565,084
Construction Work in Progress	394,942	42,626
Total Utility Plant	<u>14,586,500</u>	<u>13,559,737</u>
 <u>Accumulated Provision for Depreciation</u>		
Electric	3,030,208	2,769,423
Gas	360,520	345,726
Total Accumulated Provision for Depreciation	<u>3,390,728</u>	<u>3,115,149</u>
 Net Utility Plant	<u>11,195,772</u>	<u>10,444,588</u>
 <u>Current and Accrued Assets</u>		
Cash	148,135	1,918,883
Working Funds	377	44
Temporary Cash Investments	682,269	117,578
Customer Accounts Receivable	148,446	209,906
Other Accounts Receivable	724,432	611,434
Accumulated Provision for Uncollectible Accounts	(124,100)	(107,322)
Accounts Receivable from Associated Companies	2,555,305	1,060,337
Materials and Supplies	118,677	98,621
Prepayments	412,639	663,538
Accrued Utility Revenue	139,438	208,437
Derivative Instrument Asset Hedges	-	76,570
Total Current and Accrued Assets	<u>4,805,617</u>	<u>4,858,026</u>
 <u>Deferred Debits</u>		
Deferred Fuel Costs	225,282	20,982
Unamortized Debt Expense	139,754	154,232
Regulatory Assets	1,188,855	1,223,853
Miscellaneous Deferred Debits	6,241	53,538
Accumulated Deferred Federal Income Tax	519,248	487,212
Total Deferred Debits	<u>2,079,380</u>	<u>1,939,817</u>
 Total Assets and Other Debits	<u>\$ 18,080,769</u>	<u>\$ 17,242,431</u>

Pike County Light And Power Company
Balance Sheet
Liabilities and Stockholder's Equity
As of March 31, 2008 And 2007

Exhibit G-1
Schedule 1
Page 2 of 2

Liabilities and Other Credits

	March 31, 2008	March 31, 2007
<u>Proprietary Capital</u>		
Common Stock Issued	\$ 137,000	\$ 137,000
Miscellaneous Paid-In Capital	500,000	500,000
Retained Earnings	3,828,428	3,493,285
Other Comprehensive Income	-	11,255
Total Proprietary Capital	<u>4,465,428</u>	<u>4,141,540</u>
 <u>Long-Term Debt</u>		
Bonds-LT	<u>3,200,000</u>	<u>3,200,000</u>
 Total Capitalization	 <u>7,665,428</u>	 <u>7,341,540</u>
 <u>Noncurrent Liabilities</u>		
Provision for Rate Refunds	28,000	28,000
Pension and Benefits Reserve	<u>390,196</u>	<u>417,378</u>
Total Noncurrent Liabilities	<u>418,196</u>	<u>445,378</u>
 <u>Current and Accrued Liabilities</u>		
Accounts Payable	2,230,782	5,875,563
Accounts Payable to Associated Companies	3,947,068	89,761
Customer Deposits	158,702	133,951
Taxes Accrued	(49,740)	203,960
Interest Accrued	158,097	152,624
Other Current Liabilities	<u>20,848</u>	<u>77,502</u>
Total Current and Accrued Liabilities	<u>6,465,756</u>	<u>6,533,360</u>
 <u>Deferred Credits</u>		
Customer Advances for Construction	61,404	66,220
Other Deferred Credits	604,239	236,880
Regulatory Liabilities	197,593	178,290
Future Deferred Income Taxes	58,410	58,658
Accumulated Deferred Investment Tax Credits	25,601	31,687
Accumulated Deferred Income Taxes	<u>2,584,142</u>	<u>2,350,418</u>
Total Deferred Credits	<u>3,531,388</u>	<u>2,922,153</u>
 Total Liabilities and Equity	 <u><u>\$ 18,080,769</u></u>	 <u><u>\$ 17,242,431</u></u>

Pike County Light And Power Company
Net Book Value of Gas and Electric Plant in Service
March 31, 2008

Exhibit G-1
Schedule 2

<u>Intangible Plant</u>	Electric Plant in Service	Accumulated Provision for Depreciation & Amortization	Net Book Value
Franchise and Consents	\$ 2,675	\$ -	\$ 2,675
Total Intangible Plant	<u>2,675</u>	<u>-</u>	<u>2,675</u>

Distribution Plant

Land and Land Rights	46,091	19,826	26,266
Structures and Improvements	150,918	9,268	141,650
Station Equipment	1,517,825	124,986	1,392,839
Poles, Towers, and Fixtures	2,827,647	957,272	1,870,375
Overhead Conductors and Devices	3,074,508	511,049	2,563,459
Underground Conduit	346,078	55,591	290,487
Underground Conductors and Devices	877,125	144,311	732,814
Line Transformers	2,025,659	744,682	1,280,977
Services	949,000	330,618	618,382
Meters	458,969	56,813	402,156
Elec Demand Rec & Meters - Purchases	56,170	19,154	37,016
Street Lighting & Signal Systems	132,959	81,648	51,312
Total Distribution Plant	<u>12,462,950</u>	<u>3,055,218</u>	<u>9,407,732</u>
Retirement Work in Progress	<u>-</u>	<u>-</u>	<u>-</u>
Total	<u>\$ 12,465,625</u>	<u>\$ 3,055,218</u>	<u>\$ 9,410,407</u>

<u>Distribution Plant</u>	Gas Plant in Service	Accumulated Provision for Depreciation & Amortization	Net Book Value
Land and Land Rights	\$ 1,551	\$ 631	\$ 920
Mains	884,061	176,271	707,790
Meas. And Reg. Equip. - General	77,776	42,579	35,197
Services	511,868	97,562	414,306
Meter Installations	217,018	40,099	176,919
House Regulator Installations	16,514	1,926	14,588
Industrial Measuring and Regulating Equipment	17,146	1,452	15,694
Total Gas Plant	<u>\$ 1,725,933</u>	<u>\$ 360,520</u>	<u>1,365,413</u>
Retirement Work in Progress	<u>-</u>	<u>-</u>	<u>-</u>
Total	<u>\$ 1,725,933</u>	<u>\$ 360,520</u>	<u>\$ 1,365,413</u>

Pike County Light And Power Company
Statement of Income for Twelve Months Ending March 31, 2008

Exhibit G-1
Schedule 3

	Company Total	Electric Department	Gas Department
<u>Operating Revenues:</u>			
Residential Sales	\$ 3,240,310	\$ 1,840,378	\$ 1,399,933
Small C&I Sales	3,600,136	3,286,424	313,712
Large Commercial Sales	268,214	268,214	-
Public Lighting Sales	43,769	43,769	-
Total Sales and Delivery of Electricity	<u>7,152,430</u>	<u>5,438,785</u>	<u>1,713,644</u>
<u>Other Operating Revenues</u>			
Miscellaneous Service Revenues	(15,607)	(21,214)	5,607
Rent from Electric Property	35,557	35,557	-
Other Electric Revenues	(11,520)	(11,520)	-
Total Other Operating Revenues	<u>8,431</u>	<u>2,823</u>	<u>5,607</u>
Total Operating Revenues	<u>7,160,860</u>	<u>5,441,609</u>	<u>1,719,252</u>
<u>Operating Expenses:</u>			
Other Power Supply Expenses	1,869,724	1,869,724	-
Other Gas Supply Expenses	1,397,678	-	1,397,678
Transmission Expenses	4,607	4,607	-
Distribution Expenses	696,801	450,498	246,303
Customer Accounts Expenses	378,960	337,730	41,230
Customer Service Expenses	30,564	28,217	2,347
Sales Expenses	6	6	-
Administrative And General Expenses	1,193,813	1,090,497	103,316
Depreciation Expense	364,149	334,520	29,629
Taxes other than Income	386,601	379,888	6,713
State Income Taxes	6,509	12,060	(5,551)
Federal Income Taxes	155,574	207,388	(51,814)
Total Operating Expenses	<u>6,484,985</u>	<u>4,715,136</u>	<u>1,769,849</u>
Income from Utility Operations	<u>675,875</u>	<u>726,473</u>	<u>(50,598)</u>
<u>Other Income</u>			
Non-Operating Rental Income	-	-	-
Interest and Dividend Income	3,628	3,115	513
Miscellaneous Non-Operating Income	-	-	-
Total Other Income	<u>3,628</u>	<u>3,115</u>	<u>513</u>
<u>Taxes - Other Income Deductions:</u>			
Federal Income Taxes	(293)		(293)
Other Income Deductions	4,400	3,543	857
Total Taxes - Other Income Deductions	<u>4,107</u>	<u>3,543</u>	<u>564</u>
<u>Interest Charges:</u>			
Interest on Long Term Debt	226,240	199,355	26,885
Amortization of Debt Discount & Expense	14,478	12,758	1,720
Other Interest Expense	103,364	92,146	11,217
Allowance for Borrowed Funds Used During Construction	(3,830)	(3,830)	-
Total Interest Charges	<u>340,252</u>	<u>300,429</u>	<u>39,823</u>
Net Income	<u>\$ 335,144</u>	<u>\$ 425,616</u>	<u>\$ (90,472)</u>

Pike County Light And Power Company
Statement of Income - Gas
Twelve Months Ended March 31, 2008 and 2007

Exhibit G-1
Schedule 4

<u>Operating Revenues:</u>	March 31, 2008	March 31, 2007
Residential Sales	\$ 1,399,933	\$ 1,503,797
Commercial Sales	313,712	331,583
Other Gas Revenue	5,607	5,499
Total Gas Operating Revenues	<u>1,719,252</u>	<u>1,840,880</u>
<u>Operating Expenses:</u>		
Gas Supply Expenses	1,397,678	1,500,942
Distribution Expenses	246,303	181,626
Customer Accounts Expenses	41,230	48,773
Customer Service Expenses	2,347	1,585
Sales Expenses	-	2
Admin. And General Expenses	103,316	88,768
Depreciation Expense	29,629	41,236
Taxes other than Income	6,713	3,669
State Income Taxes	(5,551)	24,609
Federal Income Taxes	(51,814)	(38,674)
Total Operating Expense	<u>1,769,849</u>	<u>1,852,537</u>
Total Income from Gas Utility Operations	<u>(50,598)</u>	<u>(11,657)</u>
<u>Other Income:</u>		
Non-Operating Rental Income	-	-
Miscellaneous Non-Operating Income	513	6,203
Total Other Income	<u>513</u>	<u>6,203</u>
<u>Taxes - Other Deductions:</u>		
Federal Income Taxes	(293)	1,768
Other Income Deductions	857	423
Total Taxes - Other Income Deductions	<u>564</u>	<u>2,191</u>
<u>Interest Charges:</u>		
Interest on Long Term Debt	26,885	26,370
Amortization of Debt Discount & Expense	1,720	1,686
Other Interest Expense	11,217	9,986
Allowance for Borrowed Funds Used During Const.	-	(2,509)
Total Interest Charges	<u>39,823</u>	<u>35,534</u>
Net Income - Gas Operations	<u>\$ (90,472)</u>	<u>\$ (43,179)</u>

PIKE COUNTY LIGHT & POWER COMPANY
Statement of Charges Made by Orange and Rockland Utilities, Inc. to
Pike County Light & Power Company Gas Operations Under the Terms of the
Joint Operating Agreement

Exhibit G-1
Schedule 5
Page 1 of 3

Twelve Months Ended March 31, 2008

	Direct Charges	Allocated Charges	Total Charges
<u>Article 2. Balance Sheet Accounts</u>			
101 Plant In Service	\$ 8,080	\$ -	\$ 8,080
108 Accumulated Provision for Depreciation	(16,004)	-	(16,004)
131 Cash & TCI's	(760,903)	-	(760,903)
142 Customer Accounts Receivable	(278,351)	-	(278,351)
150 Materials and Supplies	8,549	-	8,549
165 Prepayments	11,000	-	11,000
182 Extraordinary Property Losses	(72,853)	-	(72,853)
190 Accumulated Deferred Income Tax	(12,000)	-	(12,000)
228 Accumulated Provision for Pension, Benefits	27,185	-	27,185
232 Accounts Payable	(2,198)	-	(2,198)
253 Other Deferred Credits	962	-	962
283 Accumulated Deferred Income Tax	12,000	-	12,000
Total Balance Sheet Charges	<u>(1,074,533)</u>	<u>-</u>	<u>(1,074,533)</u>
 <u>Article 2. Charges for Gas Operations</u>			
(Detailed on Pages 2 and 3)			
Operation and Maintenance Expense	229,680	86,653	316,333
Other Income and Expense Accounts	16,130	(776)	15,354
Total	<u>245,810</u>	<u>85,877</u>	<u>331,687</u>
 <u>Article 3. Charges for Jointly Used Property-Gas</u>			
Investment Cost	16,496	-	16,496
Federal Income Taxes	2,655	-	2,655
Depreciation Expense	18,655	-	18,655
Property Taxes	6,709	-	6,709
Insurance	(603)	-	(603)
Total	<u>43,912</u>	<u>-</u>	<u>43,912</u>
Total Gas O&M Charges	<u>\$ 289,722</u>	<u>\$ 85,877</u>	<u>\$ 375,599</u>

PIKE COUNTY LIGHT & POWER COMPANY
Joint Operating Agreement
Billing Under Article 2 - Charges for Gas Operations
Twelve Months Ended December 31, 2007

Exhibit G-1
Schedule 5
Page 2 of 3

	<u>Direct Charges</u>	<u>Allocated Charges</u>	<u>Total Charges</u>
<u>Distribution Expense</u>			
<u>Operation</u>			
870 Operation Supervision and Engineering	\$ 1,142	\$ -	\$ 1,142
871 Distribution Load Dispatching	14,532	-	14,532
874 Mains and Services Expenses	82,295	-	82,295
878 Meter and House Regulator Expenses	19,740	-	19,740
879 Customer Installation Expense	6,149	-	6,149
880 Other Expenses	41,873	-	41,873
Total Operation	<u>165,731</u>	<u>-</u>	<u>165,731</u>
<u>Maintenance</u>			
885 Maintenance Supervision and Engineering	1,142	-	1,142
887 Maintenance of Mains	33,707	-	33,707
890 Maint. Of Measuring & Regulator Station Equip.	589	-	589
892 Maintenance of Services	6,792	-	6,792
893 Maintenance of Meters and Home Regulators	4,495	-	4,495
Total Maintenance	<u>46,725</u>	<u>-</u>	<u>46,725</u>
Total Distribution Expense	<u>212,456</u>	<u>-</u>	<u>212,456</u>
<u>Customer Accounts Expense</u>			
<u>Operation</u>			
901 Supervision	-	1	1
902 Meter Reading Expense	-	4,414	4,414
903 Customer Records and Collection Expenses	1,120	14,129	15,249
Total Customer Accounts Expense	<u>1,120</u>	<u>18,544</u>	<u>19,664</u>
<u>Customer Service and Informational Expenses</u>			
<u>Operation</u>			
909 Supervision	333	751	1,084
910 Customer Assistance Expense	-	1,229	1,229
911 Informational and Instructional Expense	29	4	33
912 Miscellaneous Customer Service Expense	-	1	1
913 Rents	-	1	1
Total Customer Service and Informational Expenses	<u>\$ 362</u>	<u>\$ 1,986</u>	<u>\$ 2,348</u>

PIKE COUNTY LIGHT & POWER COMPANY
Joint Operating Agreement
Billing Under Article 2 - Charges for Gas Operations
Twelve Months Ended December 31, 2007

Exhibit G-1
Schedule 5
Page 3 of 3

Sales Promotion Expense

<u>Operation</u>			
917 Promotional Advertising	-	1	1
Total Sales Promotion Expense	-	1	1

Administrative and General Expenses

<u>Operation</u>			
920 Administrative and General Salaries	1,173	6,692	7,865
921 Office Supplies and Expenses	198	4,459	4,657
922 Administrative Expenses Transferred - Credit	110	13,564	13,674
923 Outside Services Employed	426	903	1,329
924 Property Insurance	-	364	364
925 Injuries and Damages	1,826	835	2,661
926 Employee Pensions and Benefits	12,074	37,448	49,522
930 Miscellaneous General Expenses	(80)	974	894
931 Expenses of Data Processing Equipment	15	647	662
Total Operation	15,742	65,886	81,628

Maintenance

932 Maintenance of General Plant	-	236	236

Total Administrative and General Expenses	15,742	66,122	81,864

Total Operation and Maintenance Expenses	229,680	86,653	316,333

Other Income and Expense Accounts

408 Taxes Other Than Income Taxes	5,681	(1,563)	4,118
421 Miscellaneous Non-Operating Income		459	459
426 Miscellaneous Non-Operating Deductions	505	328	833
430 Other Interest Charges	9,944	-	9,944
Total Other Income and Expense Accounts	\$ 16,130	\$ (776)	\$ 15,354

Pike County Light And Power Company
Index of Schedules
Rate of Return

Exhibit G-2

<u>Schedule</u>	<u>Title of Schedule</u>	<u>Witness</u>
(1)	Consolidated Capitalization of Orange and Rockland Utilities	Accounting Panel
(2)	Long Term Debt Schedule of Orange and Rockland Utilities	Accounting Panel
(3)	Consolidated Cost of Money for Pike County Light and Power Company	Accounting Panel

Pike County Light And Power Company
Consolidated Capitalization of Orange and Rockland Utilities, Inc.

	March 31, 2008 (Actual)		March 31, 2009 (Forecast)	
	Amount	Percent	Amount	Percent
	(000s)		(000s)	
Long Term Debt:				
Orange and Rockland	\$ 347,659		\$ 438,277	
Rockland Electric	0		0	
Pike County	3,200		3,200	
Total Long Term Debt	350,859	44.72%	441,477	48.03%
Common Stock Equity:				
Common Stock	5		5	
Premium on Capital Stock	234,657		264,057	
Capital Stock Expense	(150)		(150)	
Retained Earnings	199,223		213,826	
Total Common Stock Equity	433,735	55.28%	477,738	51.97%
Total Capitalization	\$ 784,594	100.00%	\$ 919,215	100.00%

PIKE COUNTY LIGHT AND POWER COMPANY

ORANGE AND ROCKLAND UTILITIES, INC. AND SUBSIDIARIES
LONG TERM DEBT
Forecast at March 31, 2009

Orange and Rockland Utilities, Inc.	Issue Date	Maturity Date	Amount Outstanding	Original Issue Amount	Premium or Discount	Expense of Issuance	Net Proceeds	Actual Cost of Money	Effective Annual Cost
Debtures:									
Series F, 6.50%	12/18/97	12/1/27	80,000,000	80,000,000	0	901,750	79,098,250	6.59%	5,272,000
Series G, 7.00%	3/9/99	3/1/29	45,000,000	45,000,000	(693,900)	1,338,234	42,967,866	7.38%	3,321,000
Series A, 2000, 7.50%	6/12/00	6/15/10	55,000,000	55,000,000	(925,700)	204,220	53,870,080	7.80%	4,290,000
Series A, 2005, 5.30%	4/1/05	4/1/15	40,000,000	40,000,000	(80,000)	495,000	39,425,000	5.49%	2,196,000
Series A, 2006, 5.45%	10/4/06	10/1/16	75,000,000	75,000,000	(136,500)	562,500	74,301,000	5.57%	4,177,500
Series A, 2008, 6.10%	8/1/08	8/1/18	50,000,000	50,000,000	0	625,000	49,375,000	6.27%	3,135,000
Series B, 2008, 6.74%	9/1/08	9/1/38	50,000,000	50,000,000	0	737,500	49,262,500	6.86%	3,430,000
			<u>395,000,000</u>					<u>6.54%</u>	<u>25,821,500</u>
Pollution Control Debt:									
1995, Variable Rate	8/1/95	8/1/15	44,000,000	44,000,000	0	3,571,683	40,428,317	3.71% *	1,632,400
			<u>44,000,000</u>					<u>3.71%</u>	<u>1,632,400</u>
Sub Total ORU Debt			439,000,000					6.25%	27,453,900
Unamortized Debt Discount			<u>(723,260)</u>						
Total ORU			<u>438,276,740</u>						
Pike County Light & Power Company									
First Mortgage Bonds:									
Series C, 7.07%	11/10/98	10/1/18	3,200,000	3,200,000	0	284,129	2,915,871	7.97%	255,040
Total Pike			<u>3,200,000</u>					<u>7.97%</u>	<u>255,040</u>
Consolidated Total			442,200,000						
Long Term Debt			<u>442,200,000</u>						
Unamortized Debt Discount			<u>(723,260)</u>						
Total Consolidated			<u>441,476,740</u>					<u>6.27%</u>	<u>27,708,940</u>

* Updated Annually

Pike County Light And Power Company
Consolidated Cost of Money

Forecast at March 31, 2009

	<u>Percent of Capital</u>	<u>Cost of Component</u>	<u>Weighted Cost</u>
Long Term Debt	48.03%	6.27%	3.01%
Common Stock Equity	51.97%	10.00%	5.20%
Total Capitalization	<u>100.00%</u>		<u>8.21%</u>

Pike County Light And Power Company
Index of Schedules
Gas Rate Base

Exhibit G-3

Schedule	Title of Schedule	Witness
Summary	Gas Rate Base	Accounting Panel
(1)	Plant - Additions & Retirements	Accounting Panel
(2)	Depreciation Reserve	Accounting Panel
(3)	Gas Working Capital Requirements	Accounting Panel
(4)	Changes to Rate Base for Rate Case Costs	Accounting Panel
(5)	Accumulated Deferred Income Taxes	Accounting Panel
(6)	Gas Capital Expenditures	Richard DiLoreto
(7)	Map of Matamoras Gas System	Richard DiLoreto

Pike County Light And Power Company
Gas Rate Base
At March 31, 2008 And 2009

Exhibit G-3
Summary
Page 1 of 2

Description	Actual Per Books at 3/31/08 (a)	Difference Between Historical and Future Years		Future Year at 3/31/09 (d)=(a)+(c)	Schedule No.
		Reference (b)	Amount (c)		
<u>Utility Plant:</u>					
Gas Plant in Service	\$ 1,725,900	(1a)	\$ 161,900	\$ 1,887,800	1
Common Plant in Service (Allocated)	-	(1b)	10,100	10,100	1
CWIP not taking interest	23,400		-	23,400	
Total Utility Plant	1,749,300		172,000	1,921,300	
<u>Utility Plant Reserves:</u>					
Accumulated Provision For Depreciation of Gas Plant in Service - Existing Rates	360,500	(2a)	32,700	393,200	2
- Proposed Rates	-	(2b)	3,700	3,700	2
Accumulated Provision For Depreciation of Common Plant in Service (Allocated)	-	(2c)	2,000	2,000	2
Total Utility Plant Reserves	360,500		38,400	398,900	
Net Plant	1,388,800		133,600	1,522,400	
<u>Additions to Net Plant</u>					
Working Capital Requirements:					
Cash Working Capital	42,000	(3)	(20,400)	21,600	3
Materials and Supplies	11,700		-	11,700	
Prepayments	52,100		-	52,100	
Deferred Rate Case Costs (Net of Tax)	-	(4)	58,500	58,500	4
Total Additions	105,800		38,100	143,900	
<u>Deductions to Net Plant:</u>					
Accumulated Deferred Income Taxes	(69,400)	(5)	(29,500)	(98,900)	5
Total Deductions	(69,400)		(29,500)	(98,900)	
Gas Rate Base	\$ 1,425,200		\$ 142,200	\$ 1,567,400	

Pike County Light And Power Company
Changes in Gas Rate Base
For the 12 Months Ended March 31, 2009

Exhibit G-3
Summary
Page 2 of 2

Adjustment Number	Description	Amount
(1a)	Changes in Plant in Service - Additions & Retirements	\$ 161,900
(1b)	Changes to Common Plant	10,100
(2a)	Changes to Gas Depreciation Reserve - Existing Depreciation Rates	32,700
(2b)	Changes to Gas Depreciation Reserve - Proposed Depreciation Rates	3,700
(2c)	Changes to Common Plant - Depreciation	2,000
(3)	Changes in Working Capital Requirements (O&M)	(20,400)
(4)	Changes to Rate Base for Rate Case Costs	58,500
(5)	Changes in Deferred Income Taxes	(29,500)

Pike County Light And Power Company
Statement in Support of Change No. (1a)
To Gas Plant in Service
For the Twelve Months Ended March 31, 2009

Exhibit G-3
Schedule 1
Page 1 of 2

<u>Gas Plant in Service</u>	<u>Amount</u>
Balance at March 31, 2008	\$ 1,725,900
Additions - April 1, 2008 thru March 31, 2009	\$ 108,200
Additions - April 1, 2009 thru September 30, 2009	<u>66,300</u>
Total Additions	<u>174,500</u>
Retirements - April 1, 2008 thru March 31, 2009	8,400
Retirements - April 1, 2009 thru September 30, 2009	<u>4,200</u>
Total Retirements	<u>12,600</u>
Net Additions (Change No. 1a)	<u>161,900</u>
Ending Balance at September 30, 2009	<u><u>\$ 1,887,800</u></u>

Pike County Light And Power Company
Statement in Support of Change No. (1b)
To Common Plant in Service
For the Twelve Months Ended March 31, 2009

Exhibit G-3
Schedule 1
Page 2 of 2

<u>Common Plant in Service (Allocated)</u>	<u>Amount</u>
Balance at March 31, 2008	<u>\$ -</u>
<u>Additions - April 1, 2008 thru March 31, 2009</u>	
Structures & Improvements	-
Milford Office Furniture & Equipment	<u>10,100</u>
Total Additions	<u>10,100</u>
<u>Retirements - April 1, 2008 thru March 31, 2009</u>	
	<u>-</u>
Total Retirements	<u>-</u>
Net Additions (Change No. 1b)	<u>10,100</u>
Ending Balance at March 31, 2009	<u><u>\$ 10,100</u></u>

Pike County Light And Power Company
Statement in Support of Change No. (2a and 2b)
To Gas Depreciation Reserve
For the Twelve Months Ended March 31, 2009

Exhibit G-3
Schedule 2
Page 1 of 2

Accumulated Provision for Depreciation
of Gas Plant in Service At Existing Rates

	<u>Amount</u>
Balance at March 31, 2008	\$ 360,500
Additions - April 1, 2008 thru March 31, 2009	\$ 29,700
Additions - April 1, 2009 thru September 30, 2009	<u>15,600</u>
Total Additions	<u>45,300</u>
Retirements - April 1, 2008 thru March 31, 2009	8,400
Retirements - April 1, 2009 thru September 30, 2009	<u>4,200</u>
Total Retirements	<u>12,600</u>
Net Additions (Change No. 2a)	<u>32,700</u>
Ending Balance at September 30, 2009	<u><u>\$ 393,200</u></u>

Accumulated Provision for Depreciation
of Gas Plant in Service At Proposed Rates

Gas Plant at September 30, 2009	1,887,800
Less: Non-Depreciable Plant	<u>-</u>
Depreciable Plant at September 30, 2009	1,887,800
x Proposed Composite Book Depreciation Rate	1.72%

Calculated Accruals to Depreciation Expense

For The Twelve Months Ended March 31, 2009	32,500
Less: Accruals to Depreciation Expense	<u>29,700</u>
Adjustment to Reserve Balance	\$ 2,800

Theoretical Depreciation Reserve

Based On Proposed Rates	390,585
Based On Existing Rates	<u>354,238</u>
Theoretical Excess Reserve	36,347
(Composite Book Life of 57 years - Average Age of 17 years)	<u>40</u>

Adjustment to Reserve to Reflect first year Amortization of difference between book and theoretical reserve	<u>900</u>

Total Increase/(Decrease) to Reserve Balance (Change No. 2b)	<u><u>\$ 3,700</u></u>

Pike County Light And Power
Statement in Support of Change No. (2c)
To Common Depreciation Reserve
For the Twelve Months Ended March 31, 2009

Exhibit G-3
Schedule 2
Page 2 of 2

	<u>Amount</u>
<u>Accumulated Provision for Depreciation</u> <u>of Common Plant in Service At Existing Rates</u>	
Balance at March 31, 2008	\$ -
<u>Additions - April 1, 2008 thru March 31, 2009</u>	-
Structures & Improvements	-
Office Furniture & Equipment	2,000
Total Additions	<u>2,000</u>
<u>Retirements - April 1, 2008 thru March 31, 2009</u>	
Milford Office	<u>-</u>
Total Retirements	<u>-</u>
Net Additions (Change No. 2c)	<u>2,000</u>
Ending Balance at March 31, 2009	<u><u>\$ 2,000</u></u>

Pike County Light And Power Company
Statement in Support of Change No. (3)
For The Twelve Months Ending March 31, 2009

Exhibit G-3
Schedule 3
Page 1 of 3

	Reference	Amount	(Lead) / Lag Days	T&D Dollar Days
Revenue Recovery	I	1,960,700	43.6	\$ 85,534,560
Gas Supply Expenses:				
O&R	II	1,604,000	45.0	72,180,000
Deferred Purchased Power Expense		-	-	-
Salaries & Wages	III	153,574	8.1	1,250,157
Pensions	XII	28,791	0.4	12,896
OPEBs	IV	11,209	94.1	1,054,390
Employee Welfare Expenses	IV	14,229	12.2	173,033
Joint Operating Expense	II	43,244	45.0	1,945,980
Uncollectible Accounts Accrual	V	15,900	43.6	693,621
Material & Supplies issues	XI	-	-	-
Other O&M	VI	138,664	12.6	1,754,004
Amortizations:	XI			
Rate Case Costs		22,500	-	-
PUC Assessment		4,690	-	-
Depreciation & Amortization	XI	45,800	-	-
Taxes Other Than Income Taxes	VII	7,800	16.1	125,889
Pennsylvania Sales & Use Tax	VII-A	-	35.4	-
Gain on Disposition of Utility Plant		4,300	-	-
Income Taxes:				
Federal Income Tax	IX	(16,000)	36.5	(584,000)
Deferred Federal Income Tax	XI	29,500	-	-
Investment Tax Credit	XI	(3,100)	-	-
Corporate Business Tax (State)	X	(26,500)	36.5	(967,250)
Return on Invested Capital	XI	(117,900)	-	-
 Total Requirement		<u>\$ 1,960,700</u>	<u>39.6</u>	<u>77,638,719</u>
 Net Lag			<u>4.0</u>	<u>\$ 7,895,841</u>
 Net Requirement (Net Lag / 365)				<u>\$ 21,632</u>
 Historical Cash Working Capital				<u>42,000</u>
 Net Change				<u>\$ (20,368)</u>
 Rounded				<u><u>\$ (20,400)</u></u>

Pike County Light And Power Company
Statement in Support of Change No. (3)
Gas Working Capital Materials and Supplies

Exhibit G-3
Schedule 3
Page 2 of 3

Month	Gas Plant Material and Stores Exp (1)	Common Plant Material and Stores Exp (2)	Total (3)=(1)+(2)
JAN '07	\$ 9,601	\$ 1,817	\$ 11,418
FEB '07	9,974	1,915	11,889
MAR '07	10,445	1,923	12,368
APR '07	10,535	1,895	12,429
MAY '07	10,197	2,010	12,206
JUN '07	9,654	1,939	11,593
JULY '07	10,083	1,848	11,931
AUG '07	9,867	1,963	11,831
SEP '07	9,500	1,891	11,391
OCT '07	9,296	2,002	11,297
NOV '07	9,055	1,930	10,985
DEC '07	8,935	1,920	10,855
Twelve Month Total	<u>\$ 117,141</u>	<u>\$ 23,053</u>	<u>\$ 140,194</u>
Twelve Month Average	<u>\$ 9,762</u>	<u>\$ 1,921</u>	<u>\$ 11,683</u>
Rounded			<u>\$ 11,700</u>

Pike County Light And Power Company
Statement in Support of Change (3)
Gas Working Capital Prepayments

Exhibit G-3
Schedule 3
Page 3 of 3

Month	Capital Stock	Gross Earnings	Penn Corp. Net Income	PUC Assessment	Property Insurance	Total
JAN '07	\$ 807	\$ -	\$ 2,485	\$ 820	\$ 162	\$ 4,112
FEB '07	807	(5)	5,784	656	142	7,241
MAR '07	1,767	67,340	7,473	492	122	77,072
APR '07	2,814	64,722	7,799	328	101	75,663
MAY '07	2,582	61,649	5,744	164	81	70,138
JUN '07	3,221	58,278	6,798	-	61	68,297
JULY '07	2,989	54,834	4,838	-	41	62,660
AUG '07	2,756	51,535	6,888	-	20	61,179
SEP '07	2,768	48,675	9,564	1,599	-	62,605
OCT '07	2,535	45,888	10,727	1,421	-	60,571
NOV '07	2,302	42,900	10,293	1,244	-	56,739
DEC '07	2,070	22,601	8,857	1,066	-	34,595
Twelve Month Total	\$ 27,417	\$ 518,415	\$ 87,249	\$ 7,790	\$ 729	\$ 640,872
Twelve Month Average	\$ 2,285	\$ 43,201	\$ 7,271	\$ 649	\$ 61	\$ 53,406
Rounded						\$ 53,400

Pike County Light And Power Company
Statement in Support of Change No. (4)
For the Twelve Months Ended March 31, 2009

Exhibit G - 3
Schedule 4

<u>Adjustment To Rate Base for Rate Case Costs</u>	<u>Before Tax</u>	<u>After Tax *</u>	<u>Rounded</u>
Estimated Rate Case Costs	<u>\$ 100,000</u>	<u>\$ 58,507</u>	<u>\$ 58,500</u>

* Net of SIT & FIT (1/1-41.4935%)

Pike County Light And Power Company
Statement in Support of Change No. (5)
To Accumulated Deferred Income Taxes
For the Twelve Months Ended March 31, 2009

Exhibit G-3
Schedule 5

<u>Accumulated Deferred Income Taxes</u>	<u>Amount</u>
Balance at March 31, 2008	\$ 69,400
<u>Additions - April 1, 2008 thru March 31, 2009</u>	
Tax Depreciation - Normalized	15,800
Tax Depreciation - CIAC	800
Capitalized Overhead Section 263A	<u>12,900</u>
Net Additions (Change No. 5)	<u>29,500</u>
Ending Balance at March 31, 2009	<u><u>\$ 98,900</u></u>

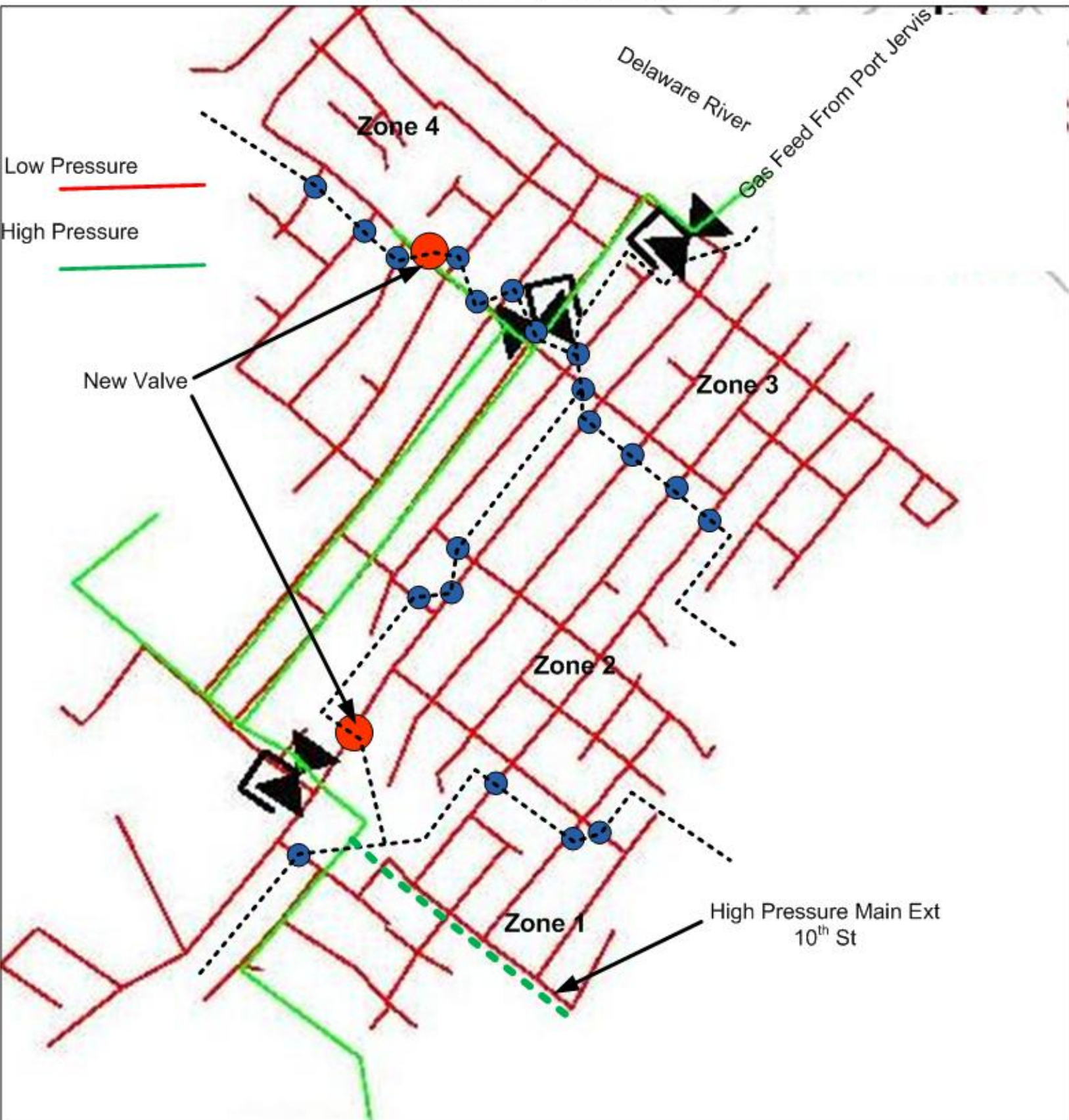
Pike County Light And Power Company

Exhibit G-3
Schedule 6

Gas Capital Expenditures for the Twelve Months Ended March 31, 2009

<u>Project Description</u>	<u>In Service Date</u>	<u>April 2008 through September 2009</u>	<u>Total</u>
Two Valve replacements	Sep-08	\$ 30.0	\$ 30.0
Mains - Replacement	Monthly	13.1	13.1
Mains - New Business	Monthly	12.9	12.9
Services - Replacement	Monthly	2.2	2.2
Services - New Business	Monthly	6.3	6.3
Regulator Installations - New Business	Monthly	0.5	0.5
Meter bars - New Business	Monthly	30.5	30.5
Regulator Materials	Monthly	0.6	0.6
Gas Meter Purchases	Monthly	8.5	8.5
Long - Term Replacement Program	Monthly	70.0	70.0

Exhibit G-3, Schedule 7



Pike County Light And Power Company
Index of Schedules
Gas Cost of Service

Exhibit G-4

Schedule	Title of Schedule	Witness
Summary	Gas Cost of Service	Accounting Panel
(1)	Changes In billed and unbilled revenue to reflect forecast sales	Accounting Panel
(2)	Change to cost of purchased gas cost to match forecast recoveries	Accounting Panel
(3)	Changes in Operations and Maintenance Expenses to reflect increases in Wages and Salaries and Additional Employee Positions	Accounting Panel
(4)	Changes in Operations and Maintenance Expenses to reflect increases in Payroll Ancillary Costs	Accounting Panel
(5)	Changes in Operation and Maintenance Expense to Reflect Rents for Milford Office	Accounting Panel
(6)	Changes in Operation and Maintenance Expenses to reflect amortization of rate case costs	Accounting Panel
(7)	Changes in Operation and Maintenance Expenses to reflect current Joint Use Rents	Accounting Panel
(8)	Change in Uncollectible Expense	Accounting Panel
(9)	Changes in Depreciation Expenses - Plant additions at existing and proposed rates, amortization of reserve deficiency, annual allowance for net salvage between the actual and theoretical depreciation reserve amortization of unrecovered plant and common plant.	Charles D. Hutcheson / Accounting Panel
(10)	Changes in Taxes Other than income to reflect Changes in Payroll Tax, Gross Earnings Tax and STAS recoveries	Accounting Panel
(11)	Changes in Gain on Sale of Utility Plant to Reflect the amortization of the net gain from the sale of the Milford Office	Accounting Panel
(12)	Calculation of Income Tax Expense	Accounting Panel

Pike County Light And Power Company
Gas Cost of Service
For the Twelve Months Ended March 31, 2008
and the Twelve Months Ended March 31, 2009

Exhibit G-4
Summary
Page 1 of 3

	12 mos. Ended March 31, 2008 (1)	Difference Between Historical and Future Years		Future Year		
		Reference	Amount	12 mos. Ended March 31, 2009 (4)=(1+3)	Proposed Rate Change (5)	As Adjusted for Add'l Revenue (6)
		(2)	(3)			
<u>Operating Revenues:</u>						
Sales of Gas - Base Rate Revenue	\$ 1,713,600	(1)	241,500	\$ 1,955,100	\$ 424,900	\$ 2,380,000
Other Operating Revenues	5,600		-	5,600	-	5,600
Total Operating Revenues	<u>1,719,200</u>		<u>241,500</u>	<u>1,960,700</u>	<u>424,900</u>	<u>2,385,600</u>
<u>Operating Expenses:</u>						
Production and Purchased Gas Expense	1,397,700	(2)	206,300	1,604,000	-	1,604,000
Other Operation and						
Maintenance Expense	393,200	(3a)	10,500	432,800	3,500	436,300
		(3b)	2,300			
		(4a)	2,100			
		(4b)	6,300			
		(5)	4,400			
		(6)	12,500			
		(7)	(700)			
		(8)	2,200			
Depreciation & Amortization Expense	29,600	(9a)	3,400	45,800	-	45,800
		(9b)	2,000			
		(9c)	900			
		(9d)	10,700			
		(9e)	(800)			
Taxes other than Income	6,700	(10)	1,100	7,800	-	7,800
Gain on disposition of Utility Plant	-	(11)	4,300	4,300	-	4,300
Total Operating Expenses	<u>1,827,200</u>		<u>267,500</u>	<u>2,094,700</u>	<u>3,500</u>	<u>2,098,200</u>
Operating Income Before Income Taxes:	(108,000)		(26,000)	(134,000)	421,400	287,400
State Income Tax	(22,700)	(12)	(3,800)	(26,500)	42,100	15,600
Federal Income Tax	19,100	(12)	(8,700)	10,400	132,800	143,200
Operating Income after Taxes	<u>\$ (104,400)</u>		<u>\$ (13,500)</u>	<u>\$ (117,900)</u>	<u>\$ 246,500</u>	<u>\$ 128,600</u>
Rate Base	<u>\$ 1,425,200</u>		<u>\$ 142,200</u>	<u>\$ 1,567,400</u>	<u>\$ -</u>	<u>\$ 1,567,400</u>
Rate of Return	<u>-7.33%</u>			<u>-7.52%</u>		<u>8.20%</u>

Pike County Light And Power Company
Calculation of Gas Revenue Requirement
For the Twelve Months Ended March 31, 2009

Exhibit G-4
Summary
Page 2 of 3

	<u>Amount</u>
Rate Base at 3/31/09	\$ 1,567,400
x Rate of Return at 3/31/09	<u>8.21%</u>
Total Return Required	128,684
Total Earned Return (Per Exhibit G-4, Summary, Page 1 of 3)	<u>(117,900)</u>
Addition Return Required	246,584
Multiplied by Retention Factor*	<u>1.7232</u>
Total Revenue Requirement	<u>\$ 424,921</u>
Rounded	<u><u>\$ 424,900</u></u>

* Retention Factor:

Additional Revenue	100.0000	424,900
Less: Revenue Taxes -- N/A	-	-
Less: Uncollectibles	<u>0.8133</u>	<u>3,500</u>
	99.1867	421,400
Less: State Income Tax @ 9.99%	<u>9.9088</u>	<u>42,100</u>
	89.2779	379,300
Less: Federal Income Tax @ 35%	<u>31.2473</u>	<u>132,800</u>
Retention Factor	<u><u>58.0306</u></u>	<u><u>246,500</u></u>
	<u>1.0000</u>	
	0.580306	
	<u><u>1.7232</u></u>	

Pike County Light And Power Company
Changes in Gas Cost of Service
For the Year Ended March 31, 2009

Exhibit G-4
Summary
Page 3 of 3

Adjustment Number	Description	Amount
(1)	Changes In billed and unbilled revenue to reflect forecast sales	\$ 241,500
(2)	Change to cost of purchased gas cost to match forecast recoveries	206,300
(3a)	Changes in Operations and Maintenance Expenses to reflect increases in Wages and Salaries	10,500
(3b)	Changes in Operation and Maintenance Expenses to reflect Increase in Additional Employee Positions	2,300
(4a)	Changes in Operation and Maintenance Expense to Reflect Estimated Payroll Ancillary Costs -- Health Insurance, Workers Comp, 401K Match	2,100
(4b)	Changes in Operation and Maintenance Expense to Reflect Estimated Payroll Ancillary Costs -- Employee Pension and OPEB Expense	6,300
(5)	Changes in Operation and Maintenance Expense to Reflect Rents for Milford Office	4,400
(6)	Changes in Operation and Maintenance Expenses to reflect amortization of rate case costs	12,500
(7)	Changes in Operation and Maintenance Expenses to reflect current Joint Use Rents	(700)
(8)	Change in Uncollectible Expense	2,200
(9a)	Changes in Depreciation Expense -- At Existing & Proposed Rates	3,400
(9b)	Changes in Depreciation Expense -- Common Plant	2,000
(9c)	Changes in Depreciation Expense -- Amortization of Reserve Deficiency	900
(9d)	Changes in Depreciation Expense - Annual allowance for Net Salvage between the Actual and Theoretical Depreciation Reserve	10,700
(9e)	Changes in Depreciation Expense -- Amortization of unrecovered plant	(800)
(10)	Changes in Taxes Other than income to reflect Changes in Payroll Tax, Realty and Gross Earnings Tax	1,100
(11)	Changes in Gain on Sale of Utility Plant to Reflect the amortization of the net gain from the sale of the Milford Office	4,300
(12)	Calculation of Income Tax Expense For the Twelve Months Ended December 31, 2008	
	- State Income Tax Adjustment	(3,800)
	- Federal Income Tax Adjustment	(8,700)

Pike County Light And Power Company

Exhibit G-4
Schedule 1

Statement in Support of Change No. (1)
To Gas Operation and Maintenance Expense
For the Twelve Months Ended March 31, 2009

Changes In billed and unbilled revenue to reflect forecast sales
and revenues at current rates.

Revenues - Twelve Months Ended March 31, 2009 (a)

Base Revenue	\$ 1,399,648
Rider Revenue (GCR)	204,388
Delivery Revenue	351,556
STAS Revenue	(534)
	<u>1,955,058</u>

Billed & Unbilled Revenues - Twelve Months Ended March 31, 2009 (a)	1,955,058
- Twelve Months Ended March 31, 2008 (b)	<u>1,713,600</u>

Net increase in Revenues	<u>\$ 241,458</u>

Rounded Total	<u><u>\$ 241,500</u></u>

Sales Volumes (MCF)

Forecast - 12 Months Ended 3/31/09	<u>135,900</u>	
Actual - 12 Months Ended 3/31/08	128,702	
Weather Normalized	<u>1,375</u>	
	130,077	
Total Increase		<u><u>5,823</u></u>
% Increase		4.3%

(a) See Exhibit G-6, Schedule 4

(b) See Exhibit G-4, Summary, Page 1 of 3

Pike County Light And Power Company

Exhibit G-4
Schedule 2

Statement in Support of Change No. (2)
To Gas Operation and Maintenance Expense
For the Twelve Months Ended March 31, 2009

Change to cost of purchase gas to match cost of gas included
revenue forecast - Adjustment 1

Base Revenue	\$ 1,399,648
Rider Revenue	204,388
Billed & Unbilled Gas Costs - Twelve Months Ended March 31, 2009	<u>1,604,036</u>
- Twelve Months Ended March 31, 2008 (a)	<u>1,397,700</u>
Net increase in Gas Costs	<u>\$ 206,336</u>
Rounded Total	<u><u>\$ 206,300</u></u>

(a) See Exhibit G-4, Summary, Page 1 of 3

Pike County Light And Power Company
Statement in Support of Change No. (3a)
To Gas Operation and Maintenance Expense
Wage and Salary Increases
For the Twelve Months Ended March 31, 2009

Exhibit G-4
Schedule 3
Page 1 of 3

Monthly Wage and Salary Increases

Normalizing Adjustment applicable to the 12 Months Ended March 31, 2008	\$ 29,167
Wage Increase and Annualization 4/1/08 through 3/31/09	1,531,195
Wage Increase and Annualization 4/1/09 through 3/31/10	<u>1,613,533</u>

Total Monthly Wage and Annualization Increases	<u>3,173,895</u>

Wage increase applicable to gas operation and maintenance expense	<u>4,319</u>

Weekly Wage and Salary Increases

Normalizing Adjustment applicable to the 12 Months Ended March 31, 2008	288,966
Wage Increase and Annualization 4/1/08 through 3/31/09	2,036,633
Wage Increase and Annualization 4/1/09 through 3/31/10	<u>2,149,547</u>

Total Weekly Wage and Annualization Increases	<u>4,475,146</u>

Wage increase applicable to gas operation and maintenance expense	<u>6,167</u>

Total Wage Increase Applicable to Pike Electric O&M Expense	<u>\$ 10,485</u>

Rounded	<u><u>\$ 10,500</u></u>

Pike County Light And Power Company
Statement in Support of Change No. (3b)
To Gas Operation and Maintenance Expense
Additional Employee Positions
For the Twelve Months Ended March 31, 2009

Exhibit G-4
Schedule 3
Page 2 of 3

Additional Monthly Employee Positions

Additional Employee Positions 4/1/08 through 3/31/09	\$ 623,488
Additional Employee Positions 4/1/09 through 3/31/10	<u>520,334</u>

Total Additional Monthly Employee Positions	<u>1,143,822</u>

Additional employee positions applicable to gas operation and maintenance expense	<u>314</u>

Additional Weekly Employee Positions

Additional Employee Positions 4/1/08 through 3/31/09	447,132
Additional Employee Positions 4/1/09 through 3/31/10	257,307

Total Additional Weekly Employee Positions	<u>704,439</u>

Additional employee positions applicable to gas operation and maintenance expense	<u>1,990</u>

Total Additional Employees Applicable to Pike Electric O&M Expense	<u>\$ 2,304</u>

Rounded Total	<u><u>\$ 2,300</u></u>

Statement in Support of
Additional Employee Positions
For the Twelve Months Ended March 31, 2009

	Number	Date Added	Consolidated Cost Allocated To	
			Pike Elect O&M	Pike Gas O&M
Weekly Paid Positions				
Overhead Linemen, 3rd Class	2	Jul-08	Yes	No
Drafting Technician	1	Jul-08	Yes	No
Drafting Technician	1	Jul-09	Yes	No
Service Layout Estimator (LTS)	1	Jul-09	Yes	Yes
Customer Service Representative	1	Jun-08	Yes	Yes
	<u>6</u>			
Monthly Paid Positions				
Reliability Engineer	1	Apr-08	Yes	No
WMS Support Specialist	1	Sep-08	Yes	No
Compliance Specialist	1	Jul-08	Yes	No
Community Relations Manager	1	Jul-08	Yes	Yes
Systems Specialist	1	Jul-08	Yes	Yes
Engineer (Career Development Rotation Program)	1	Jul-08	Yes	No
Engineer (Career Development Rotation Program)	1	Jul-10	Yes	No
Customer Programs Analyst	1	Jul-08	Yes	Yes
Labor Relations Administrator	1	Jul-09	Yes	Yes
Training Position	1	Jul-10	Yes	Yes
Mobil Workforce Administrator	1	Jul-09	Yes	No
Mobil Workforce Systems Analyst	1	Jul-10	Yes	No
Systems Specialist (ECC) - Operations Support	2	Jul-09	Yes	No
Supervisor (LTS)	1	Jul-09	Yes	No
	<u>15</u>			
Total	<u>21</u>			

Pike County Light And Power Company
Statement in Support of Change No. (4a)
To Gas Operation and Maintenance Expense
For the Twelve Months Ended March 31, 2009

Exhibit G-4
Schedule 4
Page 1 of 2

Change in Operation and Maintenance Expenses to Reflect the estimated
increase in Payroll Ancillary Costs (Health Insurance & Workers Compensation)

Wage Increase and Annualization ¹	\$ 10,485
Salary and wages for additional employees	<u>2,304</u>
Total increase in wages	\$ 12,789
 Fringe Benefit Rate	 <u>16.36%</u>
 Total Benefit Costs	 <u>\$ 2,092</u>
 Rounded Total	 <u><u>\$ 2,100</u></u>

¹ Per Exhibit G-4, Schedule 3

Pike County Light And Power Company
Statement in Support of Change No. (4b)
To Other Operation and Maintenance Expense
For the Twelve Months Ended March 31, 2009

Exhibit G-4
Schedule 4
Page 2 of 2

Adjustment to Other Operations & Maintenance Expense to Reflect
Increases in Pension and Employee Post Retirement (OPEB) Costs:

Forecast - SFAS 87 Pension Expense (12 Months Ended 3/31/09) ¹	\$ 38,207	
Less: Capitalized / Recovered Pension Costs (25%)	<u>(9,416)</u>	
Pension Expense - 12 Months Ending 3/31/09		28,791
Actual - SFAS 87 Pension Expense (12 Months Ending 3/31/08)	33,479	
Less: Capitalized / Recovered Pension Costs (25%)	<u>(8,251)</u>	
Pension Expense - 12 Months Ending 3/31/08		25,228
Adjustment for SFAS 87 Pension Cost		<u>\$ 3,563</u>
Forecast - SFAS 106 OPEB Expense (12 Months Ended 3/31/09)*	19,980	
Less: VEBA Health Insurance Reimbursements (18.4%)	(3,676)	
Capitalized / Recovered OPEB Costs (25.5%)	<u>(5,095)</u>	
OPEB Expense - 12 Months Ending 3/31/09		11,209
Actual - SFAS 106 OPEB Expense (12 Months Ended 3/31/08)	16,175	
Less: VEBA Health Insurance Reimbursements (18.4%)	(2,686)	
Capitalized / Recovered OPEB Costs (25.5%)	<u>(5,028)</u>	
OPEB Expense - 12 Months Ending 3/31/08		8,461
Adjustment for SFAS 106 OPEB Cost		<u>\$ 2,748</u>
Total Pension and OPEB		<u>\$ 6,311</u>
Total Pension and OPEB - Rounded		<u><u>\$ 6,300</u></u>

¹ Source: Actuarial Study by Buck Consultants, dated March 28, 2008

Pike County Light And Power Company

Exhibit G-4
Schedule 5

Statement in Support of Change No. (5)
To Gas Operation and Maintenance Expense
For the Twelve Months Ended March 31, 2009

Adjustment to Other Operations & Maintenance Expense to Reflect
Rent of Milford Office

Annual Rent -- Effective April 1, 2008	\$	35,000
Percentage allocable to gas		<u>12.59%</u>
Annual Expense Recovery	\$	<u>4,407</u>
Rounded Total	\$	<u><u>4,400</u></u>

Pike County Light And Power Company

Exhibit G-4
Schedule 6

Statement in Support of Change No. (6)
To Gas Operation and Maintenance Expense
For the Twelve Months Ended
March 31, 2009

Amortization of Estimated Outside Rate Case Expense

Prior Rate Case Legal Fees & Expenses Unrecoverable Balance as of March 31, 2009	\$	12,500
Estimated New Rate Case Legal Fees & Expenses		<u>100,000</u>
Total Unrecoverable Balance	\$	112,500
/ Amortization Period - Years		<u>5</u>
Annual Rate Case Expense	\$	22,500
Less : Current Rate Case Allowance		<u>10,000</u>
Amortization of Rate Case Expense	\$	<u>12,500</u>
Rounded	\$	<u><u>12,500</u></u>

Pike County Light And Power Company

Exhibit G-4
Schedule 7

Statement in Support of Change No. (7)
To Gas Operation and Maintenance Expense
For the Twelve Months Ended March 31, 2009

True-up of Joint Use Operating Expense	
Annualized Joint Use Operating Expense based on billing rate in effect at March 31, 2008	\$ 43,224
Less: Joint Operating Expense billings reflected in Operation And Maintenance Expense for the Twelve Months Ending March 31, 2008.	<u>43,914</u>
Net Change in Joint Operating Expense	\$ (690)
Rounded Total	<u><u>\$ (700)</u></u>

Pike County Light And Power Company

Exhibit G-4
Schedule 8

Statement in Support of Change No. (8)
To Gas Operation and Maintenance Expense
For the Twelve Months Ended March 31, 2009

Uncollectible Accounts Expense

Operating Revenues Before Rate Change -- Twelve Months Ending March 31, 2009		\$ 1,955,058
Uncollectible write-offs / revenues -- Twelve Months Ending March 31, 2008		<u>0.008133</u>
		\$ 15,900

Less: Uncollectible Expense reflected in Operation And
Maintenance Expense for the Twelve Months Ending March 31, 2008.

Account 904000 08	12,009	
904011 08	<u>1,692</u>	<u>13,701</u>

Net Change in Joint Operating Expense \$ 2,199

Rounded Total \$ 2,200

Pike County Light And Power Company
Statement in Support of Change No. (9a)
To Depreciation Expense
For the Twelve Months Ended March 31, 2009

Exhibit G-4
Schedule 9
Page 1 of 5

	Amount	
	<u>Gas Plant</u>	<u>Adjustment</u>
<u>Gas Plant in Service</u>		
At March 31, 2008 Per Exhibit G-3, Summary	\$ 1,725,933	
Less: Non-Depreciable Plant Per Exhibit G-1, Schedule 2	-	
Depreciable Plant at March 31, 2008	<u>1,725,933</u>	
<u>Additions - April 1, 2008 thru March 31, 2009</u>		
Distribution	108,200	
<u>Additions - April 1, 2009 thru September 30, 2009</u>		
Distribution	66,300	
Total Additions	<u>174,500</u>	
<u>Retirements - April 1, 2008 thru March 31, 2009</u>		
Distribution	8,400	
<u>Retirements - April 1, 2009 thru September 30, 2009</u>		
Distribution	4,200	
Total Retirements	<u>12,600</u>	
<u>Gas Depreciable Plant at March 31, 2009</u>	1,887,833	
x Proposed Composite Book Depreciation Rate	<u>1.72%</u>	
<u>Calculated Accruals to Depreciation Reserves</u>		
For The Twelve Months Ended March 31, 2009	32,500	
Less: 12 Months Ending March 31, 2008 (See G-4, Summary)	<u>29,600</u>	
Increase In Depreciation Expense		\$ 2,900
<u>Proposed Depreciation Rate Change</u>		
Depreciable Plant at March 31, 2009	1,887,833	
x Proposed Basis Depreciation Rate	<u>1.75%</u>	
Depreciation Expense at Proposed Rates	33,037	
Existing Rates	<u>32,500</u>	
Variation between Current and Proposed Rates		<u>537</u>
Total Increase/(Decrease) in Depreciation Expense		<u>\$ 3,437</u>
Rounded Total		<u><u>\$ 3,400</u></u>

Pike County Light And Power
Statement in Support of Change No. (9b)
To Common Depreciation Reserve
For the Twelve Months Ended March 31, 2009

Exhibit G-4
Schedule 9
Page 2 of 5

<u>Accumulated Provision for Depreciation of Common Plant in Service At Existing Rates</u>	<u>Amount</u>
Balance at March 31, 2008	\$ -
<u>Additions - April 1, 2008 thru March 31, 2009</u>	
Structures & Improvements	-
Office Furniture & Equipment	10,100
Total Additions	<u>10,100</u>
<u>Retirements - April 1, 2008 thru March 31, 2009</u>	
Milford Office	-
Total Retirements	<u>-</u>
Net Additions	10,100
Amortization Period (Years)	<u>5</u>
Annual Amortization Expense	<u>\$ 2,020</u>
Rounded	<u><u>\$ 2,000</u></u>

Pike County Light And Power Company
Statement in Support of Change No. (9c)
To Depreciation Expense
For the Twelve Months Ended March 31, 2009

Exhibit G-4
Schedule 9
Page 3 of 5

<u>Changes in Depreciation Expense - Amortization of the difference between the Actual and Theoretical Depreciation Reserve.</u>	<u>\$ Amount</u>
<u>Gas Depreciation Reserve Measured At December 31, 2007</u>	
Computed Reserve For Depreciation Based on Proposed Rates	390,585
Actual Reserve For Depreciation Based on Existing Rates	<u>354,238</u>
Excess of Book over Theoretical Reserve	<u>\$ 36,347</u>
Amortization Period - Remaining Life - Years (Composite Book Life of 57 years - Average Age of 17 years)	<u>40</u>
Annual Amortization	<u>\$ 909</u>
Rounded	<u><u>\$ 900</u></u>

Pike County Light And Power Company
Statement in Support of Change No. (9d)
To Depreciation Expense
For the Twelve Months Ended March 31, 2009

Exhibit G-4
Schedule 9
Page 4 of 5

Account Number	Gas Plant	Five Year Cumulative Net Salvage	Average Per Year	Current Salvage Allowance	(Reduction) or Additional Amount Required
376	Mains	\$ 28,985	\$ 5,797	\$ 170	\$ 5,627
378	Station Equipment	-	-	-	-
380	Services	31,621	6,324	1,320	5,004
381	Meters	-	-	(46)	46
	Total	<u>\$ 60,606</u>	<u>\$ 12,121</u>	<u>\$ 1,444</u>	<u>\$ 10,677</u>
	Rounded				<u><u>\$ 10,700</u></u>

Pike County Light And Power Company
Statement in Support of Change No. (9e)
To Depreciation Expense
For the Twelve Months Ended March 31, 2009

Exhibit G-4
Schedule 9
Page 5 of 5

<u>Amortization of Unrecovered Plant Investment</u>	<u>\$ Amount</u>
Gas Plant Retired In Place (See June 2004 Rate Case)	\$ 4,900
Less amortization through March 31, 2009	<u>3,675</u>
Balance to be Recovered	1,225
Amortization - Years	<u>5</u>
Annual Amortization	200
Amount Included in Test Year	<u>1,000</u>
Net Adjustment	<u><u>\$ (800)</u></u>

Pike County Light And Power Company
Statement in Support of Change No. (10)
To Other Tax Expense
For the Twelve Months Ended March 31, 2009

Exhibit G-4
Schedule 10
Page 1 of 2

<u>Changes in Taxes Other</u>	<u>Actual 3/31/2008 (1)</u>	<u>Changes (2)</u>	<u>Future Year 3/31/2009 (3)</u>
Payroll Taxes	\$ 6,500	\$ 7,500	\$ 1,000
Payroll Taxes Capitalized	(2,500)	(2,900)	(400)
Pa. Capital Stock	2,500	2,500	-
Misc. Other Taxes	200	200	-
STAS	(500)	-	500
	<u>\$ 6,200</u>	<u>\$ 7,300</u>	<u>\$ 1,100</u>
Rounded			<u><u>\$ 1,100</u></u>

Pike County Light And Power Company
Statement in Support of Change No. (10)
To Taxes Other than Income
For the Twelve Months Ended March 31, 2009

Exhibit G-4
Schedule 10
Page 2 of 2

Change in Taxes Other Than Income to reflect the estimated increase
in Payroll Taxes (FICA, Medicare, and Unemployment):

Wage Increase and Annualization ¹	\$ 10,485
Salary and wages for additional employees	2,304
Total increase in wages	<u>\$ 12,789</u>
x Payroll Tax Rate	<u>7.74%</u>
Total Payroll Taxes	<u>\$ 989</u>
Rounded Total	<u><u>\$ 1,000</u></u>

Change in Taxes Other Than Income to reflect the estimated increase
in Payroll Taxes Capitalized²

Payroll Taxes Capitalized at 3/31/2008	\$ (2,500)
/ Payroll Taxes at 3/31/2008	<u>6,500</u>
% of Payroll Taxes Capitalized	-38%
x Change in Payroll Taxes	<u>7,500</u>
Payroll Taxes Capitalized at 3/31/2009	<u>(2,900)</u>
Change in Payroll Taxes Capitalized	<u>\$ (400)</u>
Rounded Total	<u><u>\$ (400)</u></u>

¹ Per Exhibit G-4, Schedule 3, Page 1

² Per Exhibit G-4, Schedule 10, Page 1

Pike County Light And Power Company
Statement in Support of Change No. (11)
For The Twelve Months Ended March 31, 2009

Exhibit G-4
Schedule 11

Gain From Sale of Property
219 1/2 Broad Street, Milford, Pennsylvania

	Allocation		
	Utility Plant 50%	Non-Utility Plant 50%	Total
Contract Selling Price	\$ 180,500	\$ 180,500	\$361,000
Selling Expenses:			
- Legal & Other	1,934	1,934	3,868
Net Proceeds from Sale	178,566	178,566	357,132
Cost of Land & Structures:			
- Land	3,770	3,770	7,540
- Building	5,670	5,670	11,340
Original Purchase Price	9,440	9,440	18,880
- Building Improvements	30,613	27,897	58,510
- Less Depreciation 12/31/07	(23,040)	(20,803)	(43,843)
Book Value 12/31/07	17,013	16,534	33,547
Site Cleanup Costs:			
- BSB Construction	6,376	6,376	12,752
- Clayton Environmental	2,525	2,525	5,050
- Miller Environmental	4,157	4,157	8,314
Site Remediation Costs	13,058	13,058	26,116
Other Retirement WIP Charges	12,278	12,278	24,556
Retirement WIP at 12/31/07	25,336	25,336	33,017
Gain on Sale Before Tax	136,217	136,696	290,568
Allocation To Gas	20.28%		
Net Gas Allocation	\$ 27,625		
Less Amortization through 3/31/09	21,027		
Balance Remaining	6,598		
Amortization Period Remaining (years)	5		
Annual Amortization	1,320		
Amortization Included in Test Year	(5,607)		
Net Adjustment	\$ (4,287)		
Rounded	\$ (4,300)		

Pike County Light And Power Company
Adjustment No. (12)
Calculation of Gas State Income Taxes
For The Twelve Months Ended March 31, 2009

Exhibit G-4
Schedule 12
Page 1 of 3

	12 Months Ended 3/31/2009 (1)	Proposed Rate Change (2)	As Adjusted For Additional Revenue (3) = (1) + (2)
Operating Income Before Income Taxes	\$ (134,000)	\$ 421,400	\$ 287,400
Less Interest Expense	47,200	-	
Book Income Before FIT	<u>(181,200)</u>	<u>421,400</u>	<u>287,400</u>
<u>Section I - Flow Thru Items:</u>			
Add: Additional Taxable Income and Unallowable Deductions:			
Excess Book Prov Over Write Off	12,500	-	12,500
Book Depreciation	36,600	-	36,600
Total	<u>38,400</u>	<u>-</u>	<u>36,600</u>
Deduct: Non-Taxable Income and Additional Allowable Deductions			
Cost of Removal	12,100	-	12,100
Tax Depreciation	23,600	-	23,600
Medicare Reimbursement	3,300	-	3,300
Total	<u>39,000</u>	<u>-</u>	<u>39,000</u>
Pretax Income	(181,800)	421,400	285,000
<u>Section II - Normalized Items:</u>			
Deduct: Non-Taxable Income and Allowable Deductions			
Tax Depreciation	44,900	-	44,900
Tax Depreciation CIAC	2,200	-	2,200
Capitalized Overhead Section 263A	37,100	-	37,100
Total	<u>84,200</u>	<u>-</u>	<u>84,200</u>
Taxable Income	(266,000)	421,400	155,400
Less: State Income Tax @ 9.99%	<u>(26,600)</u>	<u>42,100</u>	<u>15,500</u>
Ordinary Income or (loss)	<u>(239,400)</u>	<u>379,300</u>	<u>139,900</u>

Pike County Light And Power Company
Adjustment No. (12)
Calculation of Gas Income Taxes
For the Twelve Months Ended March 31, 2009

Exhibit G-4
Schedule 12
Page 2 of 3

	12 Months Ended 3/31/2009 (1)	Proposed Rate Change (2)	As Adjusted For Additional Revenue (3) = (1) + (2)
Current Federal Income Tax Expense:			
Ordinary Income @ 35%	\$ (16,000)	\$ 132,800	\$ 116,800
<u>Deferred Federal Income Tax Applicable To:</u>			
Tax Depreciation - Normalized	15,800	-	15,800
Tax Depreciation - CIAC	800	-	800
Capitalized Overhead Section 263A	12,900	-	12,900
Total	29,500	-	29,500
Amortization of Deferred ITC	(3,100)	-	(3,100)
<u>Summary of Federal Income Taxes:</u>			
Current Federal Income Tax	(16,000)	132,800	116,800
Deferred Federal Income Tax	29,500	-	29,500
Amortization of Deferred ITC	(3,100)	-	(3,100)
Total	\$ 10,400	\$ 132,800	\$ 143,200

Pike County Light And Power Company

Exhibit G-4

Schedule 12

Page 3 of 3

Adjustment No. (12)
Calculation of Gas Income Taxes
For the Twelve Months Ended March 31, 2009

	12 Months Ended 3/31/2008 (1)	Proposed Rate Change (2)	As Adjusted For Additional Revenue (3) = (1) + (2)
Rate Base	\$ 1,425,200	\$ 142,200	\$ 1,567,400
Interest Component of Capitalization	<u>3.01%</u>	<u>3.01%</u>	<u>3.01%</u>
Interest Expense	<u>\$ 42,899</u>	<u>\$ 4,280</u>	<u>\$ 47,179</u>
Rounded	<u><u>\$ 42,900</u></u>	<u><u>\$ 4,300</u></u>	<u><u>\$ 47,200</u></u>

Pike County Light And Power Company
Index of Schedules
Gas Cost of Service

Exhibit G-5

<u>Schedule</u>	<u>Title of Schedule</u>	<u>Witness</u>
Summary	Gas Cost of Service and Rate Base	Accounting Panel
(1)	1% Forecast growth in Gas Base Revenues (sales)	Accounting Panel
(2)	Changes in Operations and Maintenance Expenses to reflect increases in Wages and Salaries	Accounting Panel
(3)	Changes in Operation and Maintenance Expense to Reflect Estimated Payroll Ancillary Costs -- Health Insurance, Workers Comp, 401K Match, Pension and OPEB	Accounting Panel
(4)	Inflation Increase in other O&M Expense	Accounting Panel
(5)	Change in Uncollectible Expense for higher sales revenues	Accounting Panel
(6)	Changes in Depreciation Expense	Accounting Panel
(7)	Changes in Taxes Other than income to reflect increase in payroll tax	Accounting Panel
(8)	Calculation of Income Tax Expense	Accounting Panel
(9)	Gas Plant - Additions & Retirements	Accounting Panel
(10)	Depreciation Reserve	Accounting Panel
(11)	Gas Working Capital Requirements	Accounting Panel
(12)	Changes to Rate Base for Rate Case Costs	Accounting Panel
(13)	Accumulated Deferred Income Taxes	Accounting Panel

Pike County Light And Power Company Gas Cost of Service For the Twelve Months Ended March 31, 2009, March 31, 2010 and March 31, 2011										
	Rate Year 1 Exhibit G-4 Summary Pg. 1	Ref.	Rate Year 2 Adjustments	12 mos. Ended March 31, 2010 (4)=(1+3)	Proposed Rate Change (5)	Rate Year 2 Adjusted for Proposed Increase	Amount (7)	12 mos. Ended March 31, 2011 (8)=(6+7)	Proposed Rate Change (9)	Rate Year 3 Adjusted for Proposed Increase
Operating Revenues:										
Sales of Gas - Base Rate Revenue	\$ 2,380,000	(1)	\$ 7,800	\$ 2,387,800	\$ 19,900	\$ 2,407,700	\$ 7,800	\$ 2,415,500	\$ 16,400	\$ 2,431,900
Other Operating Revenues	5,600		-	5,600	-	5,600		5,600		5,600
Total Operating Revenues	2,385,600		7,800	2,393,400	19,900	2,413,300	7,800	2,421,100	16,400	2,437,500
Operating Expenses:										
Production and Purchased Gas Expense	1,604,000			1,604,000	-	1,604,000		1,604,000		1,604,000
Other Operation and Maintenance Expense	436,300	(2) (3) (4) (5)	10,900 7,500 3,200 100	458,000	200	458,200	11,200 7,700 3,300 100	480,500	100	480,600
Depreciation & Amortization Expense	45,800	(6)	700	46,500	-	46,500	700	47,200		47,200
Taxes other than Income	7,800	(7)	600	8,400	-	8,400	700	9,100		9,100
Gain on disposition of Utility Plant	4,300		-	4,300	-	4,300	-	4,300		4,300
Total Operating Expenses	2,098,200		23,000	2,121,200	200	2,121,400	23,700	2,145,100	100	2,145,200
Operating Income Before Income Taxes:	287,400		(15,200)	272,200	19,700	291,900	(15,900)	276,000	16,300	292,300
State Income Tax	15,600	(12)	(1,600)	14,000	2,000	16,000	(1,600)	14,400	1,600	16,000
Federal Income Tax	143,200	(12)	(5,000)	138,200	6,200	144,400	(4,900)	139,500	5,100	144,600
Operating Income after Taxes	\$ 128,600		\$ (8,600)	\$ 120,000	\$ 11,500	\$ 131,500	\$ (9,400)	\$ 122,100	\$ 9,600	\$ 131,700
Rate Base	\$ 1,567,400		\$ 34,700	\$ 1,602,100	\$ -	\$ 1,602,100	\$ 1,200	\$ 1,603,300		\$ 1,603,300
Rate of Return	8.20%			7.49%		8.21%		7.62%		8.21%

Pike County Light And Power Company
Calculation of Gas Revenue Requirement
For the Twelve Months Ended
March 31, 2010 and March 31, 2011

Exhibit G-5
Summary
Page 2 of 7

	Rate Year 2 Adjustment	Rate Year 3 Adjustment
Rate Base at	\$ 1,602,100	\$ 1,603,300
x Rate of Return at	<u>8.21%</u>	<u>8.21%</u>
Total Return Required	131,532	131,631
Total Earned Return (Per Exhibit G-5, Summary, Page 1 of 3)	<u>120,000</u>	<u>122,100</u>
Addition Return Required	11,532	9,531
Multiplied by Retention Factor*	<u>1.7232</u>	<u>1.7232</u>
Total Revenue Requirement	<u>\$ 19,872</u>	<u>\$ 16,424</u>
Rounded	<u><u>\$ 19,900</u></u>	<u><u>\$ 16,400</u></u>

* Retention Factor:

Additional Revenue	100.0000	19,900	16,400
Less: Revenue Taxes -- N/A	-	-	-
Less: Uncollectibles	<u>0.8133</u>	<u>200</u>	<u>100</u>
	99.1867	19,700	16,300
Less: State Income Tax @ 9.99%	<u>9.9088</u>	<u>2,000</u>	<u>1,600</u>
	89.2779	17,700	14,700
Less: Federal Income Tax @ 35%	<u>31.2473</u>	<u>6,200</u>	<u>5,100</u>
Retention Factor	<u><u>58.0306</u></u>	<u><u>11,500</u></u>	<u><u>9,600</u></u>
	<u>1.0000</u>		
	0.580306		
	<u><u>1.7232</u></u>		

Pike County Light And Power Company
Changes in Gas Cost of Service
For the Twelve Months Ended March 31, 2010 and March 31, 2011

Exhibit G-5
Summary
Page 3 of 7

Adjustment Number	Description	Rate Year 2 Adjustment	Rate Year 3 Adjustment
(1)	1% Forecast growth in Gas Base Revenues (sales)	\$ 7,800	\$ 7,800
(2)	Changes in Operations and Maintenance Expenses to reflect increases in Wages and Salaries	10,900	11,200
(3)	Changes in Operation and Maintenance Expense to Reflect Estimated Payroll Ancillary Costs -- Health Insurance, Workers Comp, 401K Match, Pension and OPEB	7,500	7,700
(4)	Inflation Increase in other O&M Expense	3,200	3,300
(5)	Change in Uncollectible Expense for higher sales revenues	100	100
(6)	Changes in Depreciation Expense	700	700
(7)	Changes in Taxes Other than income to reflect increase in payroll tax	600	700
(8)	Calculation of Income Tax Expense For the Twelve Months Ended December 31, 2008		
	- State Income Tax Adjustment	(1,600)	(1,600)
	- Federal Income Tax Adjustment	(5,000)	(4,900)

Pike County Light And Power Company
 Levelized Rate Increase
 For the Twelve Months Ended
 March 31, 2009, March 31, 2010 and March 31, 2011

Exhibit G-5
 Summary
 Page 4 of 7

Short term Rate = 5.0%

Rate Increase	Twelve Months Ending			Cumulative Total
	March 31, 2009	March 31, 2010	March 31, 2011	
R Y - 1	\$424,900	\$424,900	\$424,900	\$1,274,700
R Y - 2		19,900	19,900	39,800
R Y - 3			16,400	16,400
Total	<u>\$ 424,900</u>	<u>\$ 444,800</u>	<u>\$ 461,200</u>	<u>\$ 1,330,900</u>
Annual rate increase w/o interest				
R Y - 1	\$ 221,817	\$ 221,817	\$ 221,817	\$ 665,450
R Y - 2		221,817	221,817	443,633
R Y - 3			221,817	221,817
Total	<u>\$ 221,817</u>	<u>\$ 443,633</u>	<u>\$ 665,450</u>	<u>\$ 1,330,900</u>
Interest	<u>\$ 3,066</u>	<u>\$ 6,149</u>	<u>\$ 3,083</u>	<u>\$ 12,298</u>
Annual rate increase w/ interest				
R Y - 1	\$ 223,866	\$ 223,866	\$ 223,866	\$ 671,599
R Y - 2		223,866	223,866	447,733
R Y - 3			223,866	223,866
Total	<u>\$ 223,866</u>	<u>\$ 447,733</u>	<u>\$ 671,599</u>	<u>\$ 1,343,198</u>
Rounded	<u><u>\$ 223,900</u></u>	<u><u>\$ 447,700</u></u>	<u><u>\$ 671,600</u></u>	<u><u>\$ 1,343,200</u></u>

Pike County Light And Power Company
Impact of Rate Increase
For the Twelve Months Ended
March 31, 2009, March 31, 2010 and March 31, 2011

Exhibit G-5
Summary
Page 5 of 7

Total Revenue Before Rate Increases: \$1,984,581

Impacts of Rate Increases:

	<u>Rate Increase</u>	<u>% Impact - Total Bill</u>
RY1 Base Rate Increase:	\$424,900	21.4%
RY2 Base Rate Increase:	19,900	1.0%
RY3 Base Rate Increase:	16,400	0.8%
Levelized Annual Rate Increase	\$223,900	11.3%

Pike County Light And Power Company
Gas Rate Base
At March 31, 2009, 2010 And 2011

Exhibit G-5
Summary
Page 6 of 7

Description	Actual Per Books at 3/31/09 (a)	Reference (b)	Rate Year 2 Adjustments (c)	Rate Year 2 As Adjusted (d)=(a)+(c)	Rate Year 3 Adjustments	Rate Year 3 As Adjusted	Schedule No.
<u>Utility Plant:</u>							
Gas Plant in Service	\$ 1,887,800	(9)	\$ 39,000	\$ 1,926,800	\$ 38,800	\$ 1,965,600	9
Common Plant in Service (Allocated)	10,100		-	10,100		10,100	
CWIP not taking interest	23,400		-	23,400	-	23,400	
Total Utility Plant	<u>1,921,300</u>		<u>39,000</u>	<u>1,960,300</u>	<u>38,800</u>	<u>1,999,100</u>	
<u>Utility Plant Reserves:</u>							
Accumulated Provision For Depreciation of Gas Plant in Service - Existing Rates	393,200	(10a)	23,900	417,100	24,100	441,200	10
- Proposed Rates	3,700		-	3,700	-	3,700	
Accumulated Provision For Depreciation of Common Plant in Service (Allocated)	2,000	(10b)	2,000	4,000	2,000	6,000	10
Total Utility Plant Reserves	<u>398,900</u>		<u>25,900</u>	<u>424,800</u>	<u>26,100</u>	<u>450,900</u>	
Net Plant	<u>1,522,400</u>		<u>13,100</u>	<u>1,535,500</u>	<u>12,700</u>	<u>1,548,200</u>	
<u>Additions to Net Plant</u>							
Working Capital Requirements:							
Cash Working Capital	21,600	(11 a & b)	33,400	55,000	300	55,300	11
Materials and Supplies	11,700		-	11,700	-	11,700	
Prepayments	52,100		-	52,100	-	52,100	
Deferred Rate Case Costs (Net of Tax)	58,500	(12)	(11,700)	46,800	(11,700)	35,100	12
Total Additions	<u>143,900</u>		<u>21,700</u>	<u>165,600</u>	<u>(11,400)</u>	<u>154,200</u>	
<u>Deductions to Net Plant:</u>							
Accumulated Deferred Income Taxes	(98,900)	(13)	(100)	(99,000)	(100)	(99,100)	13
Total Deductions	<u>(98,900)</u>		<u>(100)</u>	<u>(99,000)</u>	<u>(100)</u>	<u>(99,100)</u>	
Gas Rate Base	<u>\$ 1,567,400</u>		<u>\$ 34,700</u>	<u>\$ 1,602,100</u>	<u>\$ 1,200</u>	<u>\$ 1,603,300</u>	

Pike County Light Power Company
Changes in Gas Rate Base
For the 12 Months Ending March 31, 2010 and March 31, 2011

Exhibit G-5
Summary
Page 7 of 7

Adjustment Number	Description	Ry2 Amount	Ry3 Amount
(9)	Changes in Plant in Service - Additions & Retirements	\$ 39,000	\$ 38,800
(10a)	Changes to Depreciation Reserve - Existing Depreciation Rates	23,900	24,100
(10b)	Changes to Common Plant - Depreciation	2,000	2,000
(11 a & b)	Changes in Working Capital Requirements (O&M)	33,400	300
(12)	Changes to Rate Base for Rate Case Costs	(11,700)	(11,700)
(13)	Changes in Deferred Income Taxes	(100)	(100)

Pike County Light And Power Company

Exhibit G-5
Schedule 1

Statement in Support of Change No. (1)
To Adjust Gas Sales
For the Twelve Months Ended March 31, 2010 and March 31, 2011

<u>Changes In billed and unbilled revenue to reflect forecast sales</u>		<u>Rate Year 2 Adjustment</u>	<u>Rate Year 3 Adjustment</u>
Revenues - Twelve Months Ended March 31, 2009 ¹			
Sales of Gas - Proposed Base Rate Revenue	\$ 424,900		
Delivery Revenue	351,556		
Billed & Unbilled Revenues - Twelve Months Ended March 31, 2009	<u>776,456</u>		
Forecast Growth Rate	1%	<u>\$ 7,765</u>	<u>\$ 7,842</u>
Rounded Total		<u><u>\$ 7,800</u></u>	<u><u>\$ 7,800</u></u>
<u>Sales Volumes (MCF)</u>			
Forecast - 12 Months Ended 3/31/09	<u>135,900</u>	<u>137,259</u>	<u>138,632</u>
Total Increase		1,359	1,373
% Increase		1%	1%

¹ Per Exhibit G-4, Summary, Page 1

Pike County Light And Power Company

Exhibit G-5
Schedule 2

Statement in Support of Change No. (2)
To Gas Operation and Maintenance Expense
For the Twelve Months Ended March 31, 2010 and March 31, 2011

<u>Monthly Wage and Salary Increases ¹</u>		<u>Rate Year 2 Adjustment</u>	<u>Rate Year 3 Adjustment</u>
Normalizing Adjustment applicable to the 12 Months Ended March 31, 2008	\$ 29,167		
Wage Increase and Annualization 4/1/08 through 3/31/09	1,531,195		
Wage Increase and Annualization 4/1/09 through 3/31/10	<u>1,613,533</u>		
Total Monthly Wage and Annualization Increases	<u>3,173,895</u>		
Wage increase applicable to gas operation and maintenance expense	<u>4,319</u>		
Monthly Wage and Annualization with 3.5% Increase		<u>4,470</u>	<u>4,626</u>
<u>Monthly Wage and Salary Increases ¹</u>			
Normalizing Adjustment applicable to the 12 Months Ended March 31, 2008	288,966		
Wage Increase and Annualization 4/1/08 through 3/31/09	2,036,633		
Wage Increase and Annualization 4/1/09 through 3/31/10	<u>2,149,547</u>		
Total Weekly Wage and Annualization Increases	<u>4,475,146</u>		
Wage increase applicable to gas operation and maintenance expense	<u>6,167</u>		
Monthly Wage and Annualization with 3.5% Increase		<u>6,383</u>	<u>6,606</u>
Total Wage Increase Applicable to Pike Electric O&M Expense	\$ 10,485	\$ 10,852	\$ 11,232
Rounded	<u>\$ 10,500</u>	<u>\$ 10,900</u>	<u>\$ 11,200</u>

¹ Per Exhibit G-4, Schedule 3, Page 1

Pike County Light And Power Company

Exhibit G-5
Schedule 3

Statement in Support of Change No. (3)
To Gas Operation and Maintenance Expense
For the Twelve Months Ended March 31, 2010 and March 31, 2011

Change in Operation and Maintenance Expenses to Reflect the estimated increase in Payroll Ancillary Costs (Health Insurance & Workers Compensation)		Increase 3.5% per yr.	
		Rate Year 2 Adjustment	Rate Year 3 Adjustment
Wage Increase and Annualization ¹	\$ 10,485	\$ 10,852	\$ 11,232
Salary and wages for additional employees	2,304	-	-
Total increase in wages	\$ 12,789	\$ 10,852	\$ 11,232
Fringe Benefit Rate	16.36%	16.36%	16.36%
Total Benefit Costs	\$ 2,092	\$ 1,775	\$ 1,837
Pensions	(a)	34.18%	34.2%
Total Pensions		\$ 3,709	\$ 3,839
OPEB's	(a)	18.42%	18.42%
Total OPEB's		\$ 1,999	\$ 2,069
Total Benefits, Pensions and OPEBs		\$ 7,483	\$ 7,745
Rounded Total	\$ 2,100	\$ 7,500	\$ 7,700
Rounded Total			

¹ Per Exhibit G-4, Schedule 4

Pike County Light And Power Company

Exhibit G-5
Schedule 4

Statement in Support of Change No. (4)
To Gas Operation and Maintenance Expense
For the Twelve Months Ended March 31, 2010 and March 31, 2011

<u>Adjustment to All Other Operations & Maintenance Expenses:</u>		<u>Rate Year 2 Adjustment</u>	<u>Rate Year 3 Adjustment</u>
As Adjusted Rate Year 2009 Total O&M Expenses ¹	\$ 436,300		
<u>Less:</u>			
Salaries & Wages	(153,574)		
Pensions & OPEBs	(40,000)		
Employee Welfare Expenses	(14,229)		
Joint Operating Expense	(43,244)		
Uncollectible Accounts Accrual	(15,900)		
Amortizations	(27,190)		
Uncollectible on Additional Revenue	(3,500)		
Total Other O&M Costs	<u>\$ 138,664</u>		
x 2.3% Inflation Rate per year	2.3%	\$ 3,189	\$ 3,263
Rounded Total		<u>\$ 3,200</u>	<u>\$ 3,300</u>

¹ Per Exhibit G-4, Summary, Page 1

Pike County Light And Power Company

Exhibit G-5
Schedule 5

Statement in Support of Change No. (5)
To Gas Operation and Maintenance Expense
For the Twelve Months Ended March 31, 2010 and March 31, 2011

<u>Uncollectible Accounts Expense</u>	<u>Rate Year 2 Adjustment</u>	<u>Rate Year 3 Adjustment</u>
Revenue Adjustment due to increase in Sales ¹	\$ 7,800	\$ 7,800
x Uncollectible writeoffs / revenues -- Twelve Months Ending March 31, 2008	<u>0.008133</u>	<u>0.008133</u>
Net Change in Uncollectible Accounts Expense	<u>\$ 63</u>	<u>\$ 63</u>
Rounded Total	<u><u>\$ 100</u></u>	<u><u>\$ 100</u></u>

¹ Per Exhibit G-5, Schedule 1

Statement in Support of Change No. (6)
To Depreciation Expense
For the Twelve Months Ended March 31, 2010 and March 31, 2011

	Amount	
	<u>Gas Plant</u>	<u>Adjustment</u>
<u>Proposed Depreciation Rate Change</u> ¹		
Depreciable Plant at March 31, 2009	1,803,733	
x Proposed Basis Depreciation Rate	1.75%	
Depreciation Expense at Proposed Rates	<u>31,565</u>	
Total Increase/(Decrease) in Depreciation Expense		<u>\$ 1,965</u>
<u>Additions - Rate Year 2</u>		
Distribution	47,400	
<u>Retirements - Rate Year 2</u>		
Distribution	<u>(8,400)</u>	
Net Activity - Additions/Retirements	<u>39,000</u>	
Depreciable Plant at Rate Year 2	1,842,733	
x Proposed Basis Depreciation Rate	1.75%	
Depreciation Expense at Rate Year 2	<u>32,248</u>	
Total Increase in Depreciation Expense - Rate Year 2		<u>\$ 683</u>
Rounded Total		<u><u>\$ 700</u></u>
<u>Additions - Rate Year 3</u>		
Distribution	47,200	
<u>Retirements - Rate Year 3</u>		
Distribution	<u>(8,400)</u>	
Net Activity - Additions/Retirements	<u>38,800</u>	
<u>Gas Depreciable Plant at Rate Year 3</u>	1,881,533	
x Proposed Composite Book Depreciation Rate	1.75%	
Depreciation Expense at Rate Year 3	<u>32,927</u>	
Total Increase in Depreciation Expense - Rate Year 3		<u>\$ 679</u>
Rounded Total		<u><u>\$ 700</u></u>

¹ Per Exhibit G-4, Schedule 9, Page 1 of 5

Pike County Light And Power Company

Exhibit G-5
Schedule 7

Statement in Support of Change No. (7)
To Other Tax Expense
For the Twelve Months Ended March 31, 2010 and March 31, 2011

<u>Changes in Taxes Other</u>	<u>Future Year 3/31/2009</u>	<u>Rate Year 2 Adjustment</u>	<u>Rate Year 3 Adjustment</u>
Payroll Taxes (See Below)	\$ 1,000	\$ 800	\$ 900
Payroll Taxes Capitalized	(300)	(200)	(200)
Pa. Capital Stock	-	-	-
Misc. Other Taxes	-	-	-
	<u>\$ 700</u>	<u>\$ 600</u>	<u>\$ 700</u>
Rounded	<u><u>\$ 700</u></u>	<u><u>\$ 600</u></u>	<u><u>\$ 700</u></u>
Payroll Taxes (See Exhibit G-5, Schedule 2)		\$ 10,900	\$ 11,200
Payroll Tax Rate		<u>7.74%</u>	<u>7.74%</u>
		<u>\$ 844</u>	<u>\$ 867</u>
		<u><u>\$ 800</u></u>	<u><u>\$ 900</u></u>

Pike County Light And Power Company
Adjustment No. (8)
Calculation of Gas State Income Taxes
For The Twelve Months Ended March 31, 2010

Exhibit G-5
Schedule 8
Page 1 of 5

	12 Months Ended 3/31/2009 (1)	Proposed Rate Change (2)	As Adjusted For Additional Revenue (3) = (1) + (2)
Operating Income Before Income Taxes	(15,200)	19,900	4,700
Less Interest Expense	1,000	-	1,000
Book Income Before FIT	<u>(16,200)</u>	<u>19,900</u>	<u>3,700</u>
<u>Section I - Flow Thru Items:</u>			
Add: Additional Taxable Income and Unallowable Deductions:			
Excess Book Prov Over Write Off	-	-	-
Book Depreciation	700	-	700
Total	<u>700</u>	<u>-</u>	<u>700</u>
Deduct: Non-Taxable Income and Additional Allowable Deductions			
Cost of Removal	-	-	-
Tax Depreciation	500	-	500
Medicare Reimbursement	-	-	-
Total	<u>500</u>	<u>-</u>	<u>500</u>
Pretax Income	(16,000)	19,900	3,900
<u>Section II - Normalized Items:</u>			
Deduct: Non-Taxable Income and Allowable Deductions			
Tax Depreciation	200	-	200
Tax Depreciation CIAC	-	-	-
Capitalized Overhead Section 263A	-	-	-
Total	<u>200</u>	<u>-</u>	<u>200</u>
Taxable Income	(16,200)	19,900	3,700
Less: State Income Tax @ 9.99%	<u>(1,600)</u>	<u>2,000</u>	<u>400</u>
Ordinary Income or (loss)	<u>(14,600)</u>	<u>17,900</u>	<u>3,300</u>

Pike County Light And Power Company
Adjustment No. (8)
Calculation of Gas Income Taxes
For the Twelve Months Ended March 31, 2010

Exhibit G-5
Schedule 8
Page 2 of 5

	12 Months Ended 3/31/2009 (1)	Proposed Rate Change (2)	As Adjusted For Additional Revenue (3) = (1) + (2)
	<u> </u>	<u> </u>	<u> </u>
Current Federal Income Tax Expense:			
Ordinary Income @ 35%	\$ (5,100)	\$ 6,300	\$ 1,200
	<u> </u>	<u> </u>	<u> </u>
<u>Deferred Federal Income Tax Applicable To:</u>			
Tax Depreciation - Normalized	100	-	100
Tax Depreciation - CIAC	-	-	-
Capitalized Overhead Section 263A	-	-	-
	<u> </u>	<u> </u>	<u> </u>
Total	100	-	100
	<u> </u>	<u> </u>	<u> </u>
Amortization of Deferred ITC	-	-	-
	<u> </u>	<u> </u>	<u> </u>
<u>Summary of Federal Income Taxes:</u>			
Current Federal Income Tax	(5,100)	6,300	1,200
Deferred Federal Income Tax	100	-	100
Amortization of Deferred ITC	-	-	-
Total	<u>\$ (5,000)</u>	<u>\$ 6,300</u>	<u>\$ 1,300</u>

Pike County Light And Power Company
Adjustment No. (8)
Calculation of Gas State Income Taxes
For The Twelve Months Ended March 31, 2011

Exhibit G-5
Schedule 8
Page 3 of 5

	12 Months Ended 3/31/2010 (1)	Proposed Rate Change (2)	As Adjusted For Additional Revenue (3) = (1) + (2)
Operating Income Before Income Taxes	(15,900)	16,300	400
Less Interest Expense	-	-	-
Book Income Before FIT	<u>(15,900)</u>	<u>16,300</u>	<u>400</u>
<u>Section I - Flow Thru Items:</u>			
Add: Additional Taxable Income and Unallowable Deductions:			
Excess Book Prov Over Write Off	-	-	-
Book Depreciation	700	-	700
Total	<u>700</u>	<u>-</u>	<u>700</u>
Deduct: Non-Taxable Income and Additional Allowable Deductions			
Cost of Removal	-	-	-
Tax Depreciation	500	-	500
Medicare Reimbursement	-	-	-
Total	<u>500</u>	<u>-</u>	<u>500</u>
Pretax Income	(15,700)	16,300	600
<u>Section II - Normalized Items:</u>			
Deduct: Non-Taxable Income and Allowable Deductions			
Tax Depreciation	200	-	200
Tax Depreciation CIAC	-	-	-
Capitalized Overhead Section 263A	-	-	-
Total	<u>200</u>	<u>-</u>	<u>200</u>
Taxable Income	(15,900)	16,300	400
Less: State Income Tax @ 9.99%	<u>(1,600)</u>	<u>1,600</u>	<u>-</u>
Ordinary Income or (loss)	<u>(14,300)</u>	<u>14,700</u>	<u>400</u>

Pike County Light And Power Company
Adjustment No. (8)
Calculation of Gas Income Taxes
For the Twelve Months Ended March 31, 2011

Exhibit G-5
Schedule 8
Page 4 of 5

	12 Months Ended 3/31/2010 (1)	Proposed Rate Change (2)	As Adjusted For Additional Revenue (3) = (1) + (2)
	<u> </u>	<u> </u>	<u> </u>
Current Federal Income Tax Expense:			
Ordinary Income @ 35%	\$ (5,000)	\$ 5,100	\$ 100
	<u> </u>	<u> </u>	<u> </u>
<u>Deferred Federal Income Tax Applicable To:</u>			
Tax Depreciation - Normalized	100	-	100
Tax Depreciation - CIAC	-	-	-
Capitalized Overhead Section 263A	-	-	-
	<u> </u>	<u> </u>	<u> </u>
Total	100	-	100
	<u> </u>	<u> </u>	<u> </u>
Amortization of Deferred ITC	-	-	-
	<u> </u>	<u> </u>	<u> </u>
<u>Summary of Federal Income Taxes:</u>			
Current Federal Income Tax	(5,000)	5,100	100
Deferred Federal Income Tax	100	-	100
Amortization of Deferred ITC	-	-	-
Total	<u>\$ (4,900)</u>	<u>\$ 5,100</u>	<u>\$ 200</u>

Pike County Light And Power Company

Exhibit G-5

Schedule 8

Page 5 of 5

Adjustment No. (8)

Calculation of Gas Interest Expense

For the Twelve Months Ended March 31, 2010 and March 31, 2011

	12 Months Ended 3/31/2009 (1)	Proposed Rate Change (2)	As Adjusted For Additional Revenue (3) = (1) + (2)
Rate Base	\$ 1,567,400	\$ 34,700	\$ 1,602,100
Interest Component of Capitalization	3.01%	3.01%	3.01%
Interest Expense	\$ 47,179	\$ 1,044	\$ 48,223
Rounded	<u>\$ 47,200</u>	<u>\$ 1,000</u>	<u>\$ 48,200</u>

	12 Months Ended 3/31/2010 (1)	Proposed Rate Change (2)	As Adjusted For Additional Revenue (3) = (1) + (2)
Rate Base	\$ 1,602,100	\$ 1,200	\$ 1,603,300
Interest Component of Capitalization	3.01%	3.01%	3.01%
Interest Expense	\$ 48,223	\$ 36	\$ 48,259
Rounded	<u>\$ 48,200</u>	<u>\$ -</u>	<u>\$ 48,300</u>

Pike County Light And Power Company
Statement in Support of Change No. (9)
To Gas Plant in Service
For the Twelve Months Ending March 31, 2010 and March 31 2011

Exhibit G-5
Schedule 9

Gas Plant in Service

Rate Year 1 <u>Balance</u>	Rate Year 2 <u>Additions</u>	Rate Year 2 <u>Retirements</u>	Rate Year 2 <u>As Adjusted</u>	Rate Year 3 <u>Additions</u>	Rate Year 3 <u>Retirements</u>	Rate Year 3 <u>As Adjusted</u>
\$ 1,887,800	\$ 47,400	\$ (8,400)	\$ 1,926,800	\$ 47,200	\$ (8,400)	\$ 1,965,600

Pike County Light And Power Company
Statement in Support of Change No. (10a)
To Gas Depreciation Reserve
For the Twelve Months Ending March 31, 2010 and March 31, 2011

Exhibit G-5
Schedule 10
Page 1 of 2

Accumulated Provision for Depreciation of Gas Plant in Service

Rate Year 1	Rate Year 2		Rate Year 2	Rate Year 3		Rate Year 3
<u>Balance</u>	<u>Additions</u>	<u>Retirements</u>	<u>As Adjusted</u>	<u>Additions</u>	<u>Retirements</u>	<u>As Adjusted</u>
\$ 396,900	\$32,300	\$ (8,400)	\$ 420,800	\$32,500	\$ (8,400)	\$ 444,900

Pike County Light And Power Company
Statement in Support of Change No. (10b)
To Common Depreciation Reserve
For the Twelve Months Ending March 31, 2010 and March 31, 2011

Exhibit G-5
Schedule 10
Page 2 of 2

Accumulated Provision for Depreciation of Common Plant in Service

Rate Year 1 <u>Balance</u>	Rate Year 2		Rate Year 2 <u>As Adjusted</u>	Rate Year 3		Rate Year 3 <u>As Adjusted</u>
	<u>Additions</u>	<u>Retirements</u>		<u>Additions</u>	<u>Retirements</u>	
\$ 2,000	\$ 2,000	\$ -	\$ 4,000	\$ 2,000	\$ -	\$ 6,000

PIKE COUNTY LIGHT & POWER
SUMMARY OF CASH WORKING CAPITAL ALLOWANCE
REQUIRED FOR GAS COST OF SERVICE
TWELVE MONTHS ENDED MARCH 31, 2010

	Reference	Amount	(Lead) / Lag Days	T&D Dollar Days
Revenue Recovery	I	2,393,400	43.6	\$ 104,410,882
Gas Supply Expenses:				
O&R	II	1,604,000	45.0	72,180,000
Deferred Purchased Power Expense		-	-	-
Salaries & Wages	III	164,474	8.1	1,338,888
Pensions	XII	31,291	0.4	14,015
OPEBs	IV	13,709	94.1	1,289,560
Employee Welfare Expenses	IV	16,729	12.2	203,434
Joint Operating Expense	II	43,244	45.0	1,945,980
Uncollectible Accounts Accrual	V	19,500	43.6	850,669
Material & Supplies issues	XI	-	-	-
Other O&M	VI	141,864	12.6	1,794,482
Amortizations:				
Rate Case Costs		22,500	-	-
PUC Assessment		4,690	-	-
Depreciation & Amortization	XI	46,500	-	-
Taxes Other Than Income Taxes	VII	8,400	16.1	135,573
Pennsylvania Sales & Use Tax	VII-A	-	35.4	-
Gain on Disposition of Utility Plant		4,300	-	-
Income Taxes:				
Federal Income Tax	IX	111,700	36.5	4,077,050
Deferred Federal Income Tax	XI	29,600	-	-
Investment Tax Credit	XI	(3,100)	-	-
Corporate Business Tax (State)	X	14,000	36.5	511,000
Return on Invested Capital	XI	120,000	-	-
Total Requirement		<u>\$ 2,393,400</u>	<u>35.2</u>	<u>84,340,651</u>
		\$ -		
Net Lag			<u>8.4</u>	<u>\$ 20,070,231</u>
Net Requirement (Net Lag / 365)				<u>\$ 54,987</u>
Historical Cash Working Capital				<u>21,632</u>
Net Change				<u>\$ 33,354</u>
Rounded (11a)				<u>\$ 33,400</u>

PIKE COUNTY LIGHT & POWER
SUMMARY OF CASH WORKING CAPITAL ALLOWANCE
REQUIRED FOR GAS COST OF SERVICE
TWELVE MONTHS ENDED MARCH 31, 2011

	Reference	Amount	(Lead) / Lag Days	T&D Dollar Days
Revenue Recovery	I	2,421,100	43.6	\$ 105,619,281
Gas Supply Expenses:				
O&R	II	1,604,000	45.0	72,180,000
Deferred Purchased Power Expense		-	-	-
Salaries & Wages	III	175,674	8.1	1,430,060
Pensions	XII	33,857	0.4	15,165
OPEBs	IV	16,275	94.1	1,531,002
Employee Welfare Expenses	IV	19,296	12.2	234,645
Joint Operating Expense	II	43,244	45.0	1,945,980
Uncollectible Accounts Accrual	V	39,500	43.6	1,723,159
Material & Supplies issues	XI	-	-	-
Other O&M	VI	125,464	12.6	1,587,033
Amortizations:				
Rate Case Costs		22,500	-	-
PUC Assessment		4,690	-	-
Depreciation & Amortization	XI	47,200	-	-
Taxes Other Than Income Taxes	VII	9,100	16.1	146,870
Pennsylvania Sales & Use Tax	VII-A	-	35.4	-
Gain on Disposition of Utility Plant		4,300	-	-
Income Taxes:				
Federal Income Tax	IX	112,900	36.5	4,120,850
Deferred Federal Income Tax	XI	29,700	-	-
Investment Tax Credit	XI	(3,100)	-	-
Corporate Business Tax (State)	X	14,400	36.5	525,600
Return on Invested Capital	XI	122,100	-	-
Total Requirement		<u>\$ 2,421,100</u>	<u>35.3</u>	<u>85,440,365</u>
		\$ -		
Net Lag			<u>8.3</u>	<u>\$ 20,178,916</u>
Net Requirement (Net Lag / 365)				<u>\$ 55,285</u>
Historical Cash Working Capital				<u>54,987</u>
Net Change				<u>\$ 298</u>
Rounded (11b)				<u>\$ 300</u>

PIKE COUNTY LIGHT And POWER COMPANY

Exhibit G-5
Schedule 12

Statement in Support of Change No. (12)
For the Twelve Months Ending March 31, 2010 and March 31, 2011

Estimated Rate Case Costs

	<u>Actual Per Books at 3/31/09</u>	<u>Rate Year 2 Adjustments</u>	<u>Rate Year 2 As Adjusted</u>	<u>Rate Year 3 Adjustments</u>	<u>Rate Year 3 As Adjusted</u>
Before Tax	\$ 100,000	\$ (20,000)	\$ 80,000	\$ (20,000)	\$ 60,000
After Tax	58,507	(11,701)	46,805	(11,701)	35,104
Rounded	58,500	(11,700)	46,800	(11,700)	35,100

Pike County Light And Power Company
Statement in Support of Change No. (13)
To Accumulated Deferred Income Taxes
For the Twelve Months Ended March 31, 2010 and March 31, 2011

Exhibit G-5
Schedule 13

	<u>Rate Year 1</u>	<u>Rate Year 2</u>	<u>Rate Year 3</u>
Beginning Balance	\$ 98,900	\$ 99,000	
Tax Depreciation - Normalized	100	100	
Tax Depreciation - CIAC	-	-	
Capitalized Overhead Section 263A	-	-	
Net Additions (Change No. 13)	<u>100</u>	<u>100</u>	
Ending Balance	<u>\$ 98,900</u>	<u>\$ 99,000</u>	<u>\$ 99,100</u>

Pike County Light And Power Company
Index of Schedules
Gas Sales and Revenues

Exhibit G-6

<u>Schedule</u>	<u>Title of Schedule</u>	<u>Witness</u>
(1)	Historic Gas Sales by Service Classification	Accounting Panel
(2)	Future Gas Sales by Service Classification	Accounting Panel
(3)	Historic Gas Revenue by Service Classification	Rate Panel
(4)	Future Gas Revenue by Service Classification	Rate Panel

PIKE COUNTY LIGHT AND POWER COMPANY

**Gas Sales (CCF)
For the 12 Months Ended March 2008**

	<u>Apr</u>	<u>May</u>	<u>Jun</u>	<u>Jul</u>	<u>Aug</u>	<u>Sep</u>	<u>Oct</u>	<u>Nov</u>	<u>Dec</u>	<u>Jan</u>	<u>Feb</u>	<u>Mar</u>	<u>Total</u>
<u>Billed Sales</u>													
SC1	143,821	92,674	35,159	21,743	22,682	22,897	23,761	52,631	132,005	184,195	176,575	180,265	1,088,408
SC2	<u>30,088</u>	<u>19,634</u>	<u>9,184</u>	<u>9,192</u>	<u>9,121</u>	<u>9,950</u>	<u>8,821</u>	<u>10,658</u>	<u>28,261</u>	<u>37,304</u>	<u>36,610</u>	<u>39,455</u>	<u>248,278</u>
Subtotal	173,909	112,308	44,343	30,935	31,803	32,847	32,582	63,289	160,266	221,499	213,185	219,720	1,336,686
<u>Unbilled Sales</u>													
SC1	(46,955)	(54,978)	(10,650)	(614)	(1,403)	(980)	15,507	69,005	43,104	(6,596)	(4,994)	(41,503)	(41,057)
SC2	<u>(9,718)</u>	<u>(11,021)</u>	<u>(1,860)</u>	<u>536</u>	<u>193</u>	<u>(122)</u>	<u>4,644</u>	<u>12,854</u>	<u>6,733</u>	<u>(1,164)</u>	<u>(1,845)</u>	<u>(7,835)</u>	<u>(8,605)</u>
Subtotal	(56,673)	(65,999)	(12,510)	(78)	(1,210)	(1,102)	20,151	81,859	49,837	(7,760)	(6,839)	(49,338)	(49,662)
<u>Total Sales</u>													
SC1	96,866	37,696	24,509	21,129	21,279	21,917	39,268	121,636	175,109	177,599	171,581	138,762	1,047,351
SC2	<u>20,370</u>	<u>8,613</u>	<u>7,324</u>	<u>9,728</u>	<u>9,314</u>	<u>9,828</u>	<u>13,465</u>	<u>23,512</u>	<u>34,994</u>	<u>36,140</u>	<u>34,765</u>	<u>31,620</u>	<u>239,673</u>
Total	117,236	46,309	31,833	30,857	30,593	31,745	52,733	145,148	210,103	213,739	206,346	170,382	1,287,024

PIKE COUNTY LIGHT AND POWER COMPANY

**Gas Sales (CCF)
For the Future Test Year Ending March 2009**

	<u>Apr</u>	<u>May</u>	<u>Jun</u>	<u>Jul</u>	<u>Aug</u>	<u>Sep</u>	<u>Oct</u>	<u>Nov</u>	<u>Dec</u>	<u>Jan</u>	<u>Feb</u>	<u>Mar</u>	<u>Total</u>
<u>Billed Sales</u>													
SC1	136,000	86,000	42,000	23,000	24,000	24,000	34,000	85,000	129,000	191,000	191,000	181,000	1,146,000
SC2	<u>28,000</u>	<u>18,000</u>	<u>10,000</u>	<u>9,000</u>	<u>9,000</u>	<u>10,000</u>	<u>10,000</u>	<u>10,000</u>	<u>24,000</u>	<u>39,000</u>	<u>37,000</u>	<u>34,000</u>	<u>238,000</u>
Subtotal	164,000	104,000	52,000	32,000	33,000	34,000	44,000	95,000	153,000	230,000	228,000	215,000	1,384,000
<u>Unbilled Sales</u>													
SC1	(33,000)	(25,000)	(12,000)	(1,000)	2,000	(1,000)	24,000	27,000	26,000	10,000	(17,000)	(20,000)	(20,000)
SC2	<u>(6,000)</u>	<u>(5,000)</u>	<u>(3,000)</u>	<u>0</u>	<u>1,000</u>	<u>0</u>	<u>7,000</u>	<u>3,000</u>	<u>4,000</u>	<u>2,000</u>	<u>(4,000)</u>	<u>(4,000)</u>	<u>(5,000)</u>
Subtotal	(39,000)	(30,000)	(15,000)	(1,000)	3,000	(1,000)	31,000	30,000	30,000	12,000	(21,000)	(24,000)	(25,000)
<u>Total Sales</u>													
SC1	103,000	61,000	30,000	22,000	26,000	23,000	58,000	112,000	155,000	201,000	174,000	161,000	1,126,000
SC2	<u>22,000</u>	<u>13,000</u>	<u>7,000</u>	<u>9,000</u>	<u>10,000</u>	<u>10,000</u>	<u>17,000</u>	<u>13,000</u>	<u>28,000</u>	<u>41,000</u>	<u>33,000</u>	<u>30,000</u>	<u>233,000</u>
Total	125,000	74,000	37,000	31,000	36,000	33,000	75,000	125,000	183,000	242,000	207,000	191,000	1,359,000

PIKE COUNTY LIGHT AND POWER COMPANY

Gas Revenues for the 12 Months Ended March 2008

	<u>Apr</u>	<u>May</u>	<u>Jun</u>	<u>Jul</u>	<u>Aug</u>	<u>Sep</u>	<u>Oct</u>	<u>Nov</u>	<u>Dec</u>	<u>Jan</u>	<u>Feb</u>	<u>Mar</u>	<u>Total</u>
<u>Rate Revenue</u>													
SC1	183,076	119,905	48,899	32,196	33,483	33,757	34,827	70,434	168,469	232,926	223,138	228,621	1,409,731
SC2	<u>37,872</u>	<u>24,975</u>	<u>11,880</u>	<u>11,820</u>	<u>11,698</u>	<u>12,753</u>	<u>11,377</u>	<u>13,761</u>	<u>35,603</u>	<u>46,788</u>	<u>45,983</u>	<u>49,530</u>	<u>314,040</u>
Subtotal	220,948	144,879	60,779	44,016	45,181	46,510	46,204	84,194	204,072	279,713	269,121	278,151	1,723,771
<u>STAS Revenue (\$)</u>													
SC1	(37)	(24)	(10)	(8)	(7)	(7)	(7)	(14)	(33)	(70)	12	(46)	(250)
SC2	<u>(8)</u>	<u>(5)</u>	<u>(2)</u>	<u>(2)</u>	<u>(2)</u>	<u>(2)</u>	<u>(2)</u>	<u>(3)</u>	<u>(7)</u>	<u>(14)</u>	<u>(14)</u>	<u>(15)</u>	<u>(77)</u>
Subtotal	(44)	(29)	(12)	(10)	(9)	(9)	(9)	(17)	(41)	(84)	(2)	(61)	(327)
<u>GCR Revenue (\$)</u>													
SC1	13,916	8,968	3,402	2,405	2,194	2,008	(390)	(723)	(1,715)	(2,308)	(2,077)	(3,194)	22,487
SC2	<u>2,911</u>	<u>1,900</u>	<u>889</u>	<u>889</u>	<u>883</u>	<u>934</u>	<u>(93)</u>	<u>(136)</u>	<u>(361)</u>	<u>(476)</u>	<u>(467)</u>	<u>(503)</u>	<u>6,369</u>
Subtotal	16,827	10,868	4,290	3,295	3,077	2,942	(484)	(859)	(2,075)	(2,784)	(2,544)	(3,697)	28,856
<u>Billed Revenue</u>													
SC1	196,956	128,849	52,291	34,594	35,671	35,758	34,430	69,697	166,721	230,548	221,073	225,381	1,431,967
SC2	<u>40,776</u>	<u>26,870</u>	<u>12,767</u>	<u>12,708</u>	<u>12,579</u>	<u>13,685</u>	<u>11,281</u>	<u>13,622</u>	<u>35,235</u>	<u>46,297</u>	<u>45,502</u>	<u>49,012</u>	<u>320,333</u>
Subtotal	237,732	155,718	65,057	47,301	48,249	49,443	45,712	83,319	201,956	276,845	266,575	274,393	1,752,300
<u>Unbilled Revenue</u>													
SC1	(47,567)	(29,743)	(36,281)	(68)	(1,144)	(2,809)	22,077	87,032	63,314	(32,526)	(6,267)	(48,052)	(32,035)
SC2	<u>(9,989)</u>	<u>(5,936)</u>	<u>(6,846)</u>	<u>468</u>	<u>260</u>	<u>(136)</u>	<u>6,298</u>	<u>17,686</u>	<u>8,969</u>	<u>(6,316)</u>	<u>(1,939)</u>	<u>(9,138)</u>	<u>(6,619)</u>
Subtotal	(57,556)	(35,680)	(43,127)	400	(884)	(2,945)	28,375	104,718	72,282	(38,842)	(8,206)	(57,190)	(38,654)
<u>Total Revenue</u>													
SC1	149,389	99,105	16,010	34,526	34,526	32,949	56,507	156,729	230,035	198,022	214,806	177,329	1,399,933
SC2	<u>30,787</u>	<u>20,933</u>	<u>5,921</u>	<u>13,175</u>	<u>12,839</u>	<u>13,548</u>	<u>17,579</u>	<u>31,308</u>	<u>44,204</u>	<u>39,982</u>	<u>43,563</u>	<u>39,874</u>	<u>313,713</u>
Grand Total	<u>180,175</u>	<u>120,039</u>	<u>21,931</u>	<u>47,702</u>	<u>47,365</u>	<u>46,498</u>	<u>74,086</u>	<u>188,037</u>	<u>274,239</u>	<u>238,003</u>	<u>258,369</u>	<u>217,203</u>	<u>1,713,646</u>
<u>Base Cost of Gas</u>													
Billed	179,111	115,667	45,669	31,860	32,754	33,829	33,557	65,182	165,060	228,124	219,561	226,292	1,376,666
Unbilled	<u>(58,368)</u>	<u>(67,973)</u>	<u>(12,884)</u>	<u>(80)</u>	<u>(1,246)</u>	<u>(1,135)</u>	<u>20,754</u>	<u>84,307</u>	<u>51,328</u>	<u>(7,992)</u>	<u>(7,044)</u>	<u>(50,814)</u>	<u>(51,147)</u>
Subtotal	120,743	47,694	32,785	31,780	31,508	32,694	54,310	149,489	216,387	220,132	212,518	175,478	1,325,519

PIKE COUNTY LIGHT AND POWER COMPANY

Gas Revenues for the Future Test Year - 12 Months Ending March 2009

	<u>Apr</u>	<u>May</u>	<u>Jun</u>	<u>Jul</u>	<u>Aug</u>	<u>Sep</u>	<u>Oct</u>	<u>Nov</u>	<u>Dec</u>	<u>Jan</u>	<u>Feb</u>	<u>Mar</u>	<u>Total</u>
<u>Rate Revenue</u>													
SC1	173,393	111,667	57,327	33,733	35,035	35,099	47,459	110,408	164,778	241,345	240,886	229,461	1,480,591
SC2	<u>35,361</u>	<u>22,934</u>	<u>12,857</u>	<u>11,563</u>	<u>11,580</u>	<u>12,790</u>	<u>12,725</u>	<u>12,855</u>	<u>30,158</u>	<u>48,638</u>	<u>46,120</u>	<u>42,556</u>	<u>300,137</u>
Subtotal	208,754	134,601	70,184	45,295	46,616	47,889	60,184	123,263	194,936	289,983	287,005	272,017	1,780,727
<u>STAS Revenue (\$)</u>													
SC1	(52)	(33)	(17)	(10)	(11)	(11)	(14)	(33)	(49)	(72)	(72)	(69)	(444)
SC2	<u>(11)</u>	<u>(7)</u>	<u>(4)</u>	<u>(3)</u>	<u>(3)</u>	<u>(4)</u>	<u>(4)</u>	<u>(4)</u>	<u>(9)</u>	<u>(15)</u>	<u>(14)</u>	<u>(13)</u>	<u>(90)</u>
Subtotal	(63)	(40)	(21)	(14)	(14)	(14)	(18)	(37)	(58)	(87)	(86)	(81)	(534)
<u>GCR Revenue (\$)</u>													
SC1	(1,735)	(1,097)	(536)	(293)	(306)	5,028	7,123	17,808	27,027	40,016	40,016	37,921	170,972
SC2	<u>(357)</u>	<u>(230)</u>	<u>(128)</u>	<u>(115)</u>	<u>(115)</u>	<u>2,095</u>	<u>2,095</u>	<u>2,095</u>	<u>5,028</u>	<u>8,171</u>	<u>7,752</u>	<u>7,123</u>	<u>33,415</u>
Subtotal	(2,093)	(1,327)	(664)	(408)	(421)	7,123	9,218	19,903	32,055	48,187	47,768	45,045	204,388
<u>Billed Revenue</u>													
SC1	171,605	110,536	56,774	33,429	34,719	40,117	54,568	128,183	191,756	281,289	280,830	267,313	1,651,119
SC2	<u>34,993</u>	<u>22,697</u>	<u>12,726</u>	<u>11,445</u>	<u>11,462</u>	<u>14,881</u>	<u>14,816</u>	<u>14,946</u>	<u>35,177</u>	<u>56,794</u>	<u>53,858</u>	<u>49,667</u>	<u>333,462</u>
Subtotal	206,599	133,233	69,500	44,874	46,181	54,998	69,385	143,129	226,933	338,083	334,687	316,980	1,984,581
<u>Unbilled Revenue</u>													
SC1	(42,072)	(32,463)	(16,379)	(1,467)	2,920	(1,463)	33,502	35,070	33,212	12,636	(21,440)	(25,354)	(23,297)
SC2	<u>(7,577)</u>	<u>(6,371)</u>	<u>(3,857)</u>	<u>0</u>	<u>1,287</u>	<u>0</u>	<u>8,908</u>	<u>3,857</u>	<u>5,026</u>	<u>2,494</u>	<u>(4,986)</u>	<u>(5,007)</u>	<u>(6,227)</u>
Subtotal	(49,649)	(38,833)	(20,236)	(1,467)	4,206	(1,463)	42,409	38,927	38,239	15,130	(26,426)	(30,361)	(29,523)
<u>Total Revenue</u>													
SC1	129,534	78,074	40,395	31,962	37,638	38,655	88,070	163,253	224,968	293,925	259,389	241,959	1,627,822
SC2	<u>27,416</u>	<u>16,327</u>	<u>8,869</u>	<u>11,445</u>	<u>12,749</u>	<u>14,881</u>	<u>23,724</u>	<u>18,802</u>	<u>40,203</u>	<u>59,288</u>	<u>48,872</u>	<u>44,660</u>	<u>327,235</u>
Grand Total	<u>156,950</u>	<u>94,400</u>	<u>49,264</u>	<u>43,407</u>	<u>50,387</u>	<u>53,536</u>	<u>111,794</u>	<u>182,056</u>	<u>265,171</u>	<u>353,213</u>	<u>308,261</u>	<u>286,619</u>	<u>1,955,058</u>
<u>Base Cost of Gas</u>													
Billed	168,905	107,111	53,555	32,957	33,987	35,017	45,316	97,841	157,576	236,879	234,819	221,431	1,425,395
Unbilled	<u>(40,166)</u>	<u>(30,897)</u>	<u>(15,449)</u>	<u>(1,030)</u>	<u>3,090</u>	<u>(1,030)</u>	<u>31,927</u>	<u>30,897</u>	<u>30,897</u>	<u>12,359</u>	<u>(21,628)</u>	<u>(24,718)</u>	<u>(25,748)</u>
Subtotal	128,739	76,213	38,107	31,927	37,077	33,987	77,243	128,739	188,474	249,238	213,191	196,713	1,399,648

PIKE COUNTY LIGHT AND POWER COMPANY

**COST OF SERVICE STUDY - GAS DEPARTMENT
YEAR 2007**

EXPLANATION OF DATA SOURCES AND COSTING METHODS

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**PIKE COUNTY LIGHT AND POWER COMPANY
EMBEDDED COST OF SERVICE STUDY
GAS DEPARTMENT
YEAR 2007**

I – SUMMARY

This Embedded Cost of Service (ECOS) study allocates Pike County Light and Power Company's Gas Department costs between the Total Residential and Total Commercial service classifications based on an analysis of the rate base, including book cost of plant, and the operating expenses, including operation and maintenance expenses for the calendar year 2007. The ECOS study methodology is based on a two-step procedure. First, the costs are functionalized and classified to **Operating Functions**, as shown on **Tables 2 through 5**. The costs within each function are then allocated to **Customer Classes** based on appropriate physical quantities, such as CCF of gas sales, or other appropriate bases of allocation, such as book cost of meters and customer bills. The bases of cost allocation are shown in detail on **Table 7** as **Allocation Factors** and are further described below. The details of allocations by customer class are shown on **Tables 2 through 5**. The results of the cost allocation study are combined with class revenues to yield the rate of return statement by class shown on **Table 1**. For use in rate design, the monthly average **Customer Costs** by class are shown on **Table 6**. The revenues reflect actual 2007 gas delivery revenues; commodity-related revenues have been excluded from the study. The corresponding gas expenses have also been excluded.

II - DESCRIPTION OF OPERATING FUNCTIONS:

The operating functions shown on **Table 2, Rate Base, Table 3, Operating Expenses, and Table 5, Income Taxes** (Federal) are described below. Where applicable, these functions include fixed costs including an allocation of associated operating expenses, administrative & general expenses, and federal income taxes (F.I.T.).

Lines 1, Gas Supply

The Gas Supply Function is zero for this study.

Line 2, Distribution Demand

The Distribution Demand (“Demand Component”) consists of the balance of the distribution mains system not allocated to the customer component, and represents fixed costs incurred to distribute gas from the sellers to the firm service classes. These costs are allocated to the firm classes in proportion to their maximum one-hour non-coincident use on a zero degree day.

Line 3, Distribution Customer

The Distribution Customer (“Customer Component”) consists of the distribution mains system that would be required to connect gas customers with a minimum predominant size pipe, regardless of their demand for gas. It is apportioned to the classes based on their respective number of customers.

Line 4, Services

Services, consisting of the fixed costs of connecting the firm customers to the distribution system, are considered to be customer-related costs. These costs are allocated to the firm classes in proportion to their maximum one-hour non-coincident use on a zero degree day.

Line 5, Meters & House Regulators

Meters consist of the costs of meters that measure the customers' usage of gas, and include house

regulators and their installations. These customer costs have been distributed to the classes based on the allocation of the book costs of meters. This allocation was based on a detailed study of customers' meters for Pike's gas firm service classifications.

Line 6, Customer Installation Expenses

Customer Installation Expenses consists of the costs of investigating gas leaks, shutting off defective appliances and inspecting and maintaining installations. These costs have been apportioned among classes based on their respective number of customers.

Line 7, Customer Accounting

The Customer Accounting function consists of meter reading expenses, customer records and collection expenses and billing and accounting expenses. These costs were assigned to customer classes based on a composite allocation factor consisting of meter reading expenses and customer records and collection expenses.

Line 8, Uncollectibles

The Uncollectibles function includes the operation and maintenance expenses for uncollectibles accounts. These costs were allocated to customer classes based on their respective delivery revenues.

Line 9, Customer Service

Customer Service expenses includes expenses related to customer service and informational expenses and informational and instructional advertising expenses. These costs have been apportioned among classes based on their respective number of customers.

Line 10, Revenues

The Revenue function is used in Working Capital, Table 2, Page 5 and Payroll & Miscellaneous Taxes Table 3, Page 3.

III - DESCRIPTION OF ALLOCATION FACTORS IN TABLE 7

<u>Factor</u>	<u>Line No.</u>	<u>Description and Source</u>
D02	2	<u>Maximum Demand 1-Hour Non-Coincident</u> Maximum 1- Hour Non-Coincident Demand on a zero degree day, by class, for allocation of Distribution Demand Component costs.
E01	5	<u>Annual Gas Sales to Customers</u> Total Annual Gas sales by class are used to allocate the Gas Supply costs.
C01	8	<u>Book cost of Mains</u> This allocator assigns the Distribution Customer Component to service classes based on the total number of customers.
C02	11	<u>Book Cost – Services</u> Services are allocated to classes based on their respective Maximum 1- Hour Non-Coincident Demands on a zero degree day.
C03	14	<u>Customer Installation Expense</u> Customer installation expenses are allocated based on the total number of customers.
C04	17	<u>Book Cost of Meters</u> The C04 allocation factor is the year-end book cost of meters and meter installations and was based on a detailed meter study.

C05

20

Customer Accounting Exp

The Customer Accounting allocation factor was developed by allocating accounts that comprise the total customer accounting expenses. The allocation factor consists of Account 902, Meter Reading, allocated to the service classes based on the number of meters, Account 903, Customer Records Expense, allocated to the service classes based on the number of customers, Account 901, Supervision and Account 905, Miscellaneous Expenses, allocated to the service classes based on the sum of allocations for Account 902 and Account 903.

C06

23

Uncollectible Accounts

Total uncollectible accounts expenses were allocated to service classes based on their respective delivery revenues.

C07

26

Customer Service Expense

Total customer service expenses were allocated to the service classes based on the number of customers.

S01

29

Working Capital

The S01 allocator is used to allocate PA Corporate Net Income Taxes to the classes on the basis of revenues.

S02 32 Payroll & Miscellaneous Taxes

The S02 allocator is used to allocate State Income Tax - Pike Corporate Business Tax to the classes on the basis of revenues.

R01 35 Revenue from Sales

The Revenues from Sales allocation factor is based on annual delivery revenues.

R02 38 Other Revenues

The Other Electric Revenues allocation factor is comprised of miscellaneous revenue items allocated to the service classes based on their respective delivery revenues.

R99 41 Null Revenue Factor

K01 43 Number of Customers

Number of Customers, is the annual number of gas customers for Pike's service classes.

IV - DESCRIPTION OF CUSTOMER CLASSES:

The customer classes consist of:

Total Residential firm sales, including space heating, supplied to individual homes, apartments or other dwelling units.

Total Commercial applicable to use of non-residential firm gas, including space heating.

V - RATE OF RETURN BY CUSTOMER CLASS - TABLE 1, PAGE 1

The class allocations of the functional elements shown on **Table 2, Pages 1 through 7 Total Rate Base; Table 3, Pages 1 through 4, Total Operating Expenses; Table 4, Page 1, Operating Revenues; and Table 5, Pages 1 through 2, Income Taxes (Federal)** were consolidated and tabulated in summary form on the **Rate of Return Statement, Table 1, Page 1** detailed below:

Line 1, Operating Revenues

Total Operating Revenues are from **Table 4, Page 1, Line 4.**

Line 4, Operation and Maintenance

Total Operation and Maintenance Expenses are from **Table 3, Page 1, Line 17.**

Line 5, Depreciation and Amortization

Total Depreciation and Amortization are from **Table 3, Page 2, Line 17.**

Line 6, Payroll & Miscellaneous Taxes

Total Payroll & Miscellaneous Taxes is from **Table 3, Page 3, Line 17.**

Line 7, Federal Income Tax

Total Federal Income Taxes are from **Table 5, Page 2, Line 17.**

Line 9, Total Operating Expenses

Total Operating Expenses is the sum of **Lines 4 through 7.**

Line 11, Utility Operating Income

Total Utility Operating Income is Total Revenues on **Line 1** less Total Operating Expenses on **Line 9.**

Line 13, Utility Rate Base

Total Utility Rate Base is from **Table 2, Page 7, Line 17.**

Line 15, Rate of Return

The Rate of Return on Utility Rate Base shown on **Line 15** is calculated by dividing Utility Operating Income on **Line 11** by Utility Rate Base on **Line 13**.

Line 17, Index

The Relative Rate of Return (index), **Line 17**, the Index, is the ratio of the class return to the system return of -2.42%.

Line 19, Deviation

The Deviation is the extent (in percentage points) by which the actual rate of return for each customer class deviates from the total rate of return.

Lines 21 and 22, Tolerance Bands

A $\pm 10\%$ tolerance band has been computed around the system rate of return, and appears on **Lines 21 and 22**, respectively.

Lines 24 and 25, Revenue Surplus and Deficiency

The revenue surplus or deficiency for returns that fall outside of the tolerance band is shown on **Lines 26 and 27**, respectively.

VI - TOTAL RATE BASE - TABLE 2 - PAGES 1 - 7

Rate Base is shown on **Table 2, Pages 1-7**. The **Total Rate Base** shown on **Table 2, Page 7** is the sum of Distribution book costs of plant, less the corresponding Reserve for Depreciation plus Non-Interest Bearing CWIP (resulting in Net Plant), plus Rate Base Adjustments plus Working Capital.

Production, Transmission and Distribution Book Cost of Plant

The total Pike gas book costs are shown by function in **Table 2, Page 1, Production (Gas Supply) and Distribution Plant**. These costs are comprised of the functionalized book costs.

Description of Book Cost Functionalization from workpaper Summary Book Cost of Plant

Total Production and Storage Plant

Total Production and Storage Plant is zero in this study.

Total Transmission Plant

Total Transmission Plant is zero in this study.

Distribution Plant:

Account 374, Land and Land Rights

These costs were functionalized directly to the Distribution Demand (“Demand Component”) function.

Account 376, Mains

These costs were functionalized to the Distribution Demand (“Demand Component”) and Distribution Customer (“Customer Component”) functions based on the development of Minimum System for Pike Gas Mains.

Account 378, Measuring and Regulating Equipment

These costs were functionalized directly to the Distribution Demand (“Demand Component”) function.

Account 380, Services

The total book cost of Services was directly assigned to the services functions based on the Company’s property records data.

Accounts 381 Meters, 382 Meter Installations, 383 House Regulators, 384 House Regulator Installations

The total book cost of Meters, Meter Installations, House Regulators, House Regulator Installations was functionalized directly to the Meters and House Regulators function.

Account 385 Industrial Measuring and Regulating Station Equipment

These costs were functionalized directly to the Distribution Demand (“Demand Component”) function.

Total Distribution Plant

Total Distribution Plant is equal to the sum of Accounts 374 through 386.

Total Book Cost (Gross Plant)

Equals Total Distribution Plant.

Non-Interest-Bearing-Construction-Work-In-Progress (NIB-CWIP) - Table 2, Page 3

The average cost of NIB-CWIP monthly balances on which interest was not capitalized, is shown in total on **Line 17 of Page 3 in Column (1) of Table 2**. This amount was functionalized based on the book cost of plant, shown on **Table 2, Page 1**.

Net Plant - Table 2, Page 4

Net Plant shown on **Table 2, Page 4** by function by class is the sum of **Table 2, Page 1, Plant in Service**, less **Table 2, Page 2, Reserve for Depreciation**, plus **Table 2, Page 3, Non-Interest Bearing Construction Work In Progress**.

Working Capital - Table 2, Page 5

The working capital component of Rate Base is shown on **Table 2, Page 5**. It is developed from the cost of materials and supplies on hand, prepayments and a cash allowance for operation and maintenance expenses representing a lag of revenue collections over payments for the costs incurred. The cost of materials and supplies was allocated to all distribution functions based on their respective book cost of plant functionalizations. Prepayments were apportioned to the functions based on individual cost causation (e.g., prepayment for capital stock was allocated based on net plant, prepayment for corporate income tax was assigned directly to the revenue function,

etc.). The cash allowance for operation and maintenance expenses, excluding the cost of uncollectible accounts and the costs of purchased gas, was functionalized based on the corresponding operation and maintenance expenses.

Total Rate Base Adjustments - Table 2, Page 7

The year-end balance associated with the accumulated deferred income taxes is shown on **Line 17** of **Table 2, Page 6**.

Total Rate Base - Table 2, Page 7

The sum of the **Net Plant, Page 4, Working Capital, Page 5, and Rate Base Adjustments, Page 6**, comprises the **Total Rate Base**, and is shown on **Page 7 of Table 2**.

VII - TABLE 3 OPERATING EXPENSES

Operating Expenses are shown on **Table 3, Pages 1-4**. **Total Operating Expenses** are the sum of **Total Operation and Maintenance Expenses** consisting of Gas Supply, Distribution, Customer Accounting, Uncollectibles, Customer Service and Administrative and General Expenses plus **Total Other Expenses** (Depreciation Expenses and Payroll and Miscellaneous Taxes).

Operation and Maintenance Expenses

Table 3, Page 1, Operation and Maintenance costs are derived from the company's accounting data organized by account. These costs are transferred to the Operation and Maintenance Expense workpaper including adjustments and allocations for Administrative and General Expenses.

Accounts 800 – 813 Production (Gas Supply)

Total gas supply expenses that represent natural gas purchases were adjusted out of the study.

Accounts 870-893 - Distribution Expenses

Account 870, Supervision and Engineering

The Supervision and Engineering expense related to Operation was reallocated to Operation Accounts 871 - 880 in the Reallocation column.

Account 871, Load Dispatch

These costs were functionalized directly to the Distribution Demand Component function.

Account 874, Mains and Services

These costs were functionalized to the Distribution Demand Component, Customer Demand Component and the Services functions based on book cost for Account 376, Mains and Account 380, Services.

Account 878, Meters and House Regulators

These costs were functionalized directly to the Meters and House Regulators function.

Account 879, Customer Installations

These costs were functionalized direct to the Installation on Customers' Premises function.

Account 880, Other Expenses

These costs were functionalized to the Distribution Demand Component, Distribution Customer Component, Services and Meters and House Regulators functions based on the total book cost of distribution plant.

Total Distribution Operation Expense

Total Distribution Operation Expense is equal to the sum of Account 870 through Account 880.

Account 885, Maintenance Supervision and Engineering

The Supervision and Engineering expense related to Maintenance was reallocated to Maintenance Expense Accounts 886 – 893 in the Reallocation column.

Account 887, Maintenance of Mains

These costs were functionalized to the Distribution Demand Component and the Distribution Customer Component based on the book cost of Account 376, Mains.

Account 890, Maintenance of Measuring and Regulating Station Equipment-Industrial

These costs were functionalized to the Distribution Demand Component function based on the book costs of Account 378, Measuring and Regulating Equipment.

Account 892, Maintenance of Services

These costs were functionalized to the Services function based on book cost of Account 380, Services.

Account 893, Maintenance of Meters and House Regulators

These costs were functionalized direct to the Meters and House Regulators function.

Total Distribution Maintenance Expenses

The Total Distribution Maintenance Expenses is the sum of Account 885 through Account 893.

Total Distribution Operation and Maintenance Expenses excluding Rents

This represents the sum of Total Distribution Operation Expenses and Total Distribution Maintenance Expenses.

Account 895, Rents

These costs were functionalized to the Distribution Demand Component, Distribution Customer Component, Services and Meters and House Regulators based on the total book cost of distribution plant.

Total Distribution Expenses

This represents the sum of Total Distribution Operation and Maintenance Expenses and Rent Expenses.

Accounts 901 – 903, 905 & 906 – Customer Accounting

Customer Accounting expenses, consisting of meter reading expenses and accounting expenses were functionalized directly to the Customer Accounting function.

Account 904 – Uncollectibles

These costs were functionalized directly to the Uncollectibles function.

Accounts 907-916 – Total Customer Service

Customer Service expenses were functionalized directly to the Customer Service function.

Accounts 920-933 Administrative and General Expenses

Company Labor was used as the basis of functionalization for Accounts 920, 921, 922, 923, 925, 926, 928, 929, 930.2, 930.4 and 932. Accounts 924, 930.1, 931 and 933 were functionalized based on adjusted Distribution O&M Expenses.

Total Adjusted O&M

This represents the sum of Total Distribution Expenses, Customer Accounting, Uncollectibles, Customer Service and Administrative and General Expenses.

Total Adjusted O&M excluding Rents

This represents Total Adjusted O&M Expenses less Account 895, Rents.

Depreciation and Amortization Expense Table 3, Page 2

Depreciation Expenses shown on **Table 3, Page 2** were identified with each plant account or group of accounts and functionalized in proportion to the corresponding book cost of plant.

Payroll and Miscellaneous Taxes - Table 3, Page 3

Payroll and Miscellaneous Taxes shown on **Table 3, Page 3** includes Federal and State Unemployment Insurance Taxes and Federal Social Security Tax, and were functionalized on a labor basis. From those taxes, Capitalized or Recovered Taxes were subtracted. These taxes were

also functionalized on labor. Pike Corporate Business tax is also included on this table. It was functionalized directly to the revenue function and allocated to service classes in the study based on their respective delivery revenues.

Total Other Expenses

Total Other Expenses is the sum of Depreciation Expenses, and Payroll and Miscellaneous Taxes.

Total Operating Expenses – Table 3, Page 4

The Grand Total tabulated on **Table 3, Page 4, Total Operating Expenses**, is the sum of the Total Adjusted O&M and Total Other Expenses.

VIII - TOTAL OPERATING REVENUES - TABLE 4, PAGE 1

Operating Revenues are tabulated on **Table 4, Page 1**. The **Total Operating Revenues** are the sum of **Lines 1 through 2** as shown below.

Line 1, Revenues From Sales R01

The revenues reflect actual 2007 gas delivery revenues. Commodity-related revenues have been excluded from the study.

Line 2, Other Gas Revenues, R02

Other Operating Revenues are shown on **Line 2**. They have been allocated to service classes based on their respective delivery revenues.

Line 4, Total Operating Revenues

Total Operating Revenues shown on **Line 4, Table 4** is the sum of **Lines 1 through 2**.

IX – FEDERAL INCOME TAXES – Table 5, Pages 1 through 2

Federal Income Taxes are shown on **Table 5, Pages 1 and 2**. The **Federal Income Tax Computation** shown on **Table 5, Page 2** was calculated at 35% of taxable income plus **FIT Adjustments, Table 5, Page 1**. FIT amounts by function are not the final amounts because they do not include the revenue functional amounts that are determined in subsequent calculations. Results are presented on a functional basis to maintain a consistent report format. The total federal income tax by class is shown on **Line 17 of Table 5, Page 2**.

Federal Income Tax Adjustments – FIT Table 5, Page 1

Federal Income Tax Adjustments shown on **Table 5, Page 1 (work paper Development of Total FIT Adjustments 2007 Pike Gas ECOS Study)** are the sum of their respective Deductions and Additions, which are both calculated in the same manner in the following three steps:

First- Deductions are listed and their individual's cost causation (for functionalization purposes) are identified. Each individual deduction item is multiplied by 35% and the resulting sign is reversed.

Second - Additions are listed and matched to their corresponding tax deduction. Individual deductions from above are added to the corresponding tax additions resulting in a net tax adjustment for each individual tax item. Any net tax adjustment of an individual item resulting in less than a difference of $\pm$ \$100 is then adjusted to zero for simplification.

Third - The resulting net tax adjustment of all individual tax items with the same cost causation are aggregated and then functionalized on the applicable basis. This results in a Total FIT Adjustment by function, shown in **Table 5, Page 1**.

X – CUSTOMER COST BY CLASS - Table 6, Page 1

These are gas system costs considered to be customer related and are shown, by class, on Table 6, Page 1.

Line 1, Number of Customers

The number of customers in each class from the allocation factor **K01**.

Line 3, Rate Base

The customer related rate base shown for each class from **Table 2, Page 7, Line 15**. Also included in the customer cost calculation is a reallocated portion of the revenue function.

Line 5, Total Customer Operating Exps.

The customer related operating expenses shown from **Table 3, Page 4, Line 15**. Also included in the customer cost calculation is a reallocated portion of the revenue function.

Line 6, Monthly Op. Exps Cost/Cust

The monthly amount for operating expenses per customer shown on Line 6 is calculated starting with **Line 5** divided by **Line 1**, then the results are divided by 12.

Line 8, Return @ -2.42% (Customer)

The applied rate of return on rate base of -2.42% is the Total System Rate of Return developed in this study, shown on **Table 1, Page 1, Column 1, Line 15**.

Line 9, F.I.T. Percent on Return

The F.I.T. Percent on Return, **Line 9** developed by dividing the sum of the Total Company Federal Income Taxes as shown on **Table 1, Page 1, Column 1, Line 7** by the Total System Utility Operating Income (return) shown on **Table 1, Column 1, Line 11**.

Line 10, Income Tax On Return

The Return of **Line 8** multiplied by the F.I.T. Percent on Return **Line 9**, results in the Income Taxes on Return on a class-by-class basis.

Line 11, Total Return & F.I.T.

The Total Return & F.I.T. shown on **Line 11** is the sum of **Line 8**, Return and **Line 10**, Income Tax on Return.

Line 12, Monthly Ret. F.I.T. Cost/Cust.

The monthly amount for Return and Income Taxes per customer is calculated starting with **Line 11** divided by **Line 1**, then the results are divided by 12.

Line 14, Monthly Customer Costs

The Monthly Customer Costs are the sum of **Line 6** and **Line 12**.

	TOTAL GAS SYSTEM (1)	TOTAL RESIDENTIAL (2)	TOTAL COMMERICAL (3)
RATE OF RETURN STATEMENT			
1 TOTAL OPERATING REVENUES	347,159	290,073	57,086
2			
3 OPERATING EXPENSES			
4 OPERATION & MAINTENANCE	380,962	343,035	37,927
5 DEPRECIATION	29,040	25,781	3,259
6 PAYROLL & MISC. TAXES	15,525	13,365	2,160
7 FEDERAL INCOME TAX	(45,278)	(48,252)	2,974
8			
9 TOTAL OPERATING EXPENSES	380,250	333,930	46,320
10			
11 UTILITY OPERATING INCOME	(33,090)	(43,857)	10,767
12			
13 UTILITY RATE BASE	1,364,747	1,220,372	144,375
14			
15 RATE OF RETURN (%)	-2.42%	-3.59%	7.46%
16			
17 INDEX	1.00	1.48	-3.08
18			
19 DEVIATION	0.00	-1.17	9.88
20			
21 TOLERANCE BAND +10%	-2.67%		
22 TOLERANCE BAND -10%	-2.18%		
23			
24 REVENUE SURPLUS	22,488	0	22,488
25 REVENUE DEFICIENCY	26,502	26,502	0
	=====	=====	=====

				TOTAL GAS SYSTEM (1)	TOTAL RESIDENTIAL (2)	TOTAL COMMERICAL (3)
PLANT IN SERVICE						
1	GAS SUPPLY	E	E01	0	0	0
2	DISTRIBUTION - DEMAND	D	D02	224,906	199,949	24,957
3	DISTRIBUTION - CUSTOMER	C	C01	737,163	688,323	48,840
4	SERVICES	C	C02	496,228	441,163	55,065
5	METERS & HOUSE REGULATORS	C	C04	231,782	182,634	49,148
6	CUSTOMER INSTALLATION	C	C03	0	0	0
7	CUSTOMER ACCOUNTING	C	C05	0	0	0
8	UNCOLLECTIBLES	C	C06	0	0	0
9	CUSTOMER SERVICE	C	C07	0	0	0
10	REVENUES	R	R99	0	0	0
11						
12	TOTAL REVENUE	R		0	0	0
13	TOTAL DEMAND	D		224,906	199,949	24,957
14	TOTAL COMMODITY	E		0	0	0
15	TOTAL CUSTOMER	C		1,465,173	1,312,120	153,053
16						
17	TOTAL			1,690,079	1,512,069	178,010
				=====	=====	=====

				TOTAL GAS SYSTEM (1)	TOTAL RESIDENTIAL (2)	TOTAL COMMERICAL (3)
DEPRECIATION RESERVE						
1	GAS SUPPLY	E	E01	0	0	0
2	DISTRIBUTION - DEMAND	D	D02	69,595	61,872	7,723
3	DISTRIBUTION - CUSTOMER	C	C01	147,408	137,642	9,766
4	SERVICES	C	C02	97,526	86,704	10,822
5	METERS & HOUSE REGULATORS	C	C04	39,709	31,289	8,420
6	CUSTOMER INSTALLATION	C	C03	0	0	0
7	CUSTOMER ACCOUNTING	C	C05	0	0	0
8	UNCOLLECTIBLES	C	C06	0	0	0
9	CUSTOMER SERVICE	C	C07	0	0	0
10	REVENUES	R	R99	0	0	0
11						
12	TOTAL REVENUE	R		0	0	0
13	TOTAL DEMAND	D		69,595	61,872	7,723
14	TOTAL COMMODITY	E		0	0	0
15	TOTAL CUSTOMER	C		284,643	255,634	29,009
16						
17	TOTAL			354,238	317,507	36,731
				=====	=====	=====

				TOTAL GAS SYSTEM (1)	TOTAL RESIDENTIAL (2)	TOTAL COMMERICAL (3)
NON-INTEREST BEARING CWIP						
1	GAS SUPPLY	E	E01	0	0	0
2	DISTRIBUTION - DEMAND	D	D02	2,395	2,129	266
3	DISTRIBUTION - CUSTOMER	C	C01	7,851	7,331	520
4	SERVICES	C	C02	5,285	4,699	586
5	METERS & HOUSE REGULATORS	C	C04	2,469	1,945	524
6	CUSTOMER INSTALLATION	C	C03	0	0	0
7	CUSTOMER ACCOUNTING	C	C05	0	0	0
8	UNCOLLECTIBLES	C	C06	0	0	0
9	CUSTOMER SERVICE	C	C07	0	0	0
10	REVENUES	R	R99	0	0	0
11						
12	TOTAL REVENUE	R		0	0	0
13	TOTAL DEMAND	D		2,395	2,129	266
14	TOTAL COMMODITY	E		0	0	0
15	TOTAL CUSTOMER	C		15,605	13,975	1,630
16						
17	TOTAL			18,000	16,104	1,896
				=====	=====	=====

			TOTAL GAS SYSTEM (1)	TOTAL RESIDENTIAL (2)	TOTAL COMMERICAL (3)
NET PLANT					
1	GAS SUPPLY	E	0	0	0
2	DISTRIBUTION - DEMAND	D	157,706	140,206	17,500
3	DISTRIBUTION - CUSTOMER	C	597,606	558,012	39,594
4	SERVICES	C	403,987	359,158	44,829
5	METERS & HOUSE REGULATORS	C	194,542	153,291	41,251
6	CUSTOMER INSTALLATION	C	0	0	0
7	CUSTOMER ACCOUNTING	C	0	0	0
8	UNCOLLECTIBLES	C	0	0	0
9	CUSTOMER SERVICE	C	0	0	0
10	REVENUES	R	0	0	0
11					
12	TOTAL REVENUE	R	0	0	0
13	TOTAL DEMAND	D	157,706	140,206	17,500
14	TOTAL COMMODITY	E	0	0	0
15	TOTAL CUSTOMER	C	1,196,135	1,070,460	125,675
16					
17	TOTAL		1,353,841	1,210,666	143,175
			=====	=====	=====

				TOTAL GAS SYSTEM (1)	TOTAL RESIDENTIAL (2)	TOTAL COMMERICAL (3)
WORKING CAPITAL						
1	GAS SUPPLY	E	E01	0	0	0
2	DISTRIBUTION - DEMAND	D	D02	8,372	7,443	929
3	DISTRIBUTION - CUSTOMER	C	C01	22,768	21,260	1,508
4	SERVICES	C	C02	13,773	12,245	1,528
5	METERS & HOUSE REGULATORS	C	C04	5,485	4,322	1,163
6	CUSTOMER INSTALLATION	C	C03	949	886	63
7	CUSTOMER ACCOUNTING	C	C05	3,431	3,200	231
8	UNCOLLECTIBLES	C	C06	0	0	0
9	CUSTOMER SERVICE	C	C07	257	240	17
10	REVENUES	R	S01	7,271	6,075	1,196
11						
12	TOTAL REVENUE	R		7,271	6,075	1,196
13	TOTAL DEMAND	D		8,372	7,443	929
14	TOTAL COMMODITY	E		0	0	0
15	TOTAL CUSTOMER	C		46,663	42,152	4,511
16						
17	TOTAL			62,306	55,670	6,636
				=====	=====	=====

				TOTAL GAS SYSTEM (1)	TOTAL RESIDENTIAL (2)	TOTAL COMMERICAL (3)
TOTAL RATE BASE ADJUSTMENTS						
1	GAS SUPPLY	E	E01	0	0	0
2	DISTRIBUTION - DEMAND	D	D02	(5,987)	(5,323)	(664)
3	DISTRIBUTION - CUSTOMER	C	C01	(22,689)	(21,186)	(1,503)
4	SERVICES	C	C02	(15,338)	(13,636)	(1,702)
5	METERS & HOUSE REGULATORS	C	C04	(7,386)	(5,820)	(1,566)
6	CUSTOMER INSTALLATION	C	C03	0	0	0
7	CUSTOMER ACCOUNTING	C	C05	0	0	0
8	UNCOLLECTIBLES	C	C06	0	0	0
9	CUSTOMER SERVICE	C	C07	0	0	0
10	REVENUES	R	S01	0	0	0
11						
12	TOTAL REVENUE	R		0	0	0
13	TOTAL DEMAND	D		(5,987)	(5,323)	(664)
14	TOTAL COMMODITY	E		0	0	0
15	TOTAL CUSTOMER	C		(45,413)	(40,642)	(4,771)
16						
17	TOTAL			(51,400)	(45,964)	(5,436)
				=====	=====	=====

			TOTAL GAS SYSTEM (1)	TOTAL RESIDENTIAL (2)	TOTAL COMMERICAL (3)
TOTAL RATE BASE					
1	GAS SUPPLY	E	0	0	0
2	DISTRIBUTION - DEMAND	D	160,091	142,326	17,765
3	DISTRIBUTION - CUSTOMER	C	597,685	558,086	39,599
4	SERVICES	C	402,422	357,766	44,656
5	METERS & HOUSE REGULATORS	C	192,641	151,793	40,848
6	CUSTOMER INSTALLATION	C	949	886	63
7	CUSTOMER ACCOUNTING	C	3,431	3,200	231
8	UNCOLLECTIBLES	C	0	0	0
9	CUSTOMER SERVICE	C	257	240	17
10	REVENUES	R	7,271	6,075	1,196
11					
12	TOTAL REVENUE	R	7,271	6,075	1,196
13	TOTAL DEMAND	D	160,091	142,326	17,765
14	TOTAL COMMODITY	E	0	0	0
15	TOTAL CUSTOMER	C	1,197,385	1,071,971	125,414
16					
17	TOTAL		1,364,747	1,220,372	144,375
			=====	=====	=====

				TOTAL GAS SYSTEM (1)	TOTAL RESIDENTIAL (2)	TOTAL COMMERICAL (3)
OPERATION & MAINTENANCE						
1	GAS SUPPLY	E	E01	0	0	0
2	DISTRIBUTION - DEMAND	D	D02	51,869	46,113	5,756
3	DISTRIBUTION - CUSTOMER	C	C01	150,882	140,885	9,997
4	SERVICES	C	C02	88,185	78,399	9,786
5	METERS & HOUSE REGULATORS	C	C04	34,357	27,072	7,285
6	CUSTOMER INSTALLATION	C	C03	8,469	7,908	561
7	CUSTOMER ACCOUNTING	C	C05	30,783	28,712	2,071
8	UNCOLLECTIBLES	C	C06	14,105	11,786	2,319
9	CUSTOMER SERVICE	C	C07	2,312	2,160	153
10	REVENUES	R	R99	0	0	0
11						
12	TOTAL REVENUE	R		0	0	0
13	TOTAL DEMAND	D		51,869	46,113	5,756
14	TOTAL COMMODITY	E		0	0	0
15	TOTAL CUSTOMER	C		329,093	296,922	32,171
16						
17	TOTAL			380,962	343,035	37,927
				=====	=====	=====

				TOTAL GAS SYSTEM (1)	TOTAL RESIDENTIAL (2)	TOTAL COMMERICAL (3)
DEPRECIATION & AMORTIZATION						
1	GAS SUPPLY	E	E01	0	0	0
2	DISTRIBUTION - DEMAND	D	D02	4,841	4,304	537
3	DISTRIBUTION - CUSTOMER	C	C01	10,585	9,884	701
4	SERVICES	C	C02	8,574	7,623	951
5	METERS & HOUSE REGULATORS	C	C04	5,040	3,971	1,069
6	CUSTOMER INSTALLATION	C	C03	0	0	0
7	CUSTOMER ACCOUNTING	C	C05	0	0	0
8	UNCOLLECTIBLES	C	C06	0	0	0
9	CUSTOMER SERVICE	C	C07	0	0	0
10	REVENUES	R	R99	0	0	0
11						
12	TOTAL REVENUE	R		0	0	0
13	TOTAL DEMAND	D		4,841	4,304	537
14	TOTAL COMMODITY	E		0	0	0
15	TOTAL CUSTOMER	C		24,199	21,478	2,721
16						
17	TOTAL			29,040	25,781	3,259
				=====	=====	=====

				TOTAL GAS SYSTEM (1)	TOTAL RESIDENTIAL (2)	TOTAL COMMERICAL (3)
PAYROLL & MISC. TAXES						
1	GAS SUPPLY	E	E01	0	0	0
2	DISTRIBUTION - DEMAND	D	D02	831	739	92
3	DISTRIBUTION - CUSTOMER	C	C01	2,651	2,475	176
4	SERVICES	C	C02	1,638	1,456	182
5	METERS & HOUSE REGULATORS	C	C04	698	550	148
6	CUSTOMER INSTALLATION	C	C03	93	87	6
7	CUSTOMER ACCOUNTING	C	C05	240	224	16
8	UNCOLLECTIBLES	C	C06	0	0	0
9	CUSTOMER SERVICE	C	C07	15	14	1
10	REVENUES	R	S02	9,359	7,820	1,539
11						
12	TOTAL REVENUE	R		9,359	7,820	1,539
13	TOTAL DEMAND	D		831	739	92
14	TOTAL COMMODITY	E		0	0	0
15	TOTAL CUSTOMER	C		5,335	4,806	529
16						
17	TOTAL			15,525	13,365	2,160
				=====	=====	=====

			TOTAL GAS SYSTEM (1)	TOTAL RESIDENTIAL (2)	TOTAL COMMERICAL (3)
TOTAL OPERATING EXPENSES					
1	GAS SUPPLY	E	0	0	0
2	DISTRIBUTION - DEMAND	D	57,541	51,156	6,385
3	DISTRIBUTION - CUSTOMER	C	164,118	153,245	10,873
4	SERVICES	C	98,397	87,478	10,919
5	METERS & HOUSE REGULATORS	C	40,095	31,593	8,502
6	CUSTOMER INSTALLATION	C	8,562	7,995	567
7	CUSTOMER ACCOUNTING	C	31,023	28,936	2,087
8	UNCOLLECTIBLES	C	14,105	11,786	2,319
9	CUSTOMER SERVICE	C	2,327	2,174	154
10	REVENUES	R	9,359	7,820	1,539
11					
12	TOTAL REVENUE	R	9,359	7,820	1,539
13	TOTAL DEMAND	D	57,541	51,156	6,385
14	TOTAL COMMODITY	E	0	0	0
15	TOTAL CUSTOMER	C	358,627	323,206	35,421
16					
17	TOTAL		425,528	382,182	43,346
			=====	=====	=====

				TOTAL GAS SYSTEM (1)	TOTAL RESIDENTIAL (2)	TOTAL COMMERICAL (3)
OPERATING REVENUES						
1	REVENUES FROM SALES	R	R01	341,552	285,388	56,164
2	OTHER GAS REVENUES	R	R02	5,607	4,685	922
3						
4	TOTAL OPERATING REVENUES			347,159	290,073	57,086
				=====	=====	=====

				TOTAL GAS SYSTEM (1)	TOTAL RESIDENTIAL (2)	TOTAL COMMERICAL (3)
FIT ADJUSTMENTS						
1	GAS SUPPLY	E	E01	0	0	0
2	DISTRIBUTION - DEMAND	D	D02	(976)	(868)	(108)
3	DISTRIBUTION - CUSTOMER	C	C01	(5,948)	(5,554)	(394)
4	SERVICES	C	C02	(9,577)	(8,514)	(1,063)
5	METERS & HOUSE REGULATORS	C	C04	(1,240)	(977)	(263)
6	CUSTOMER INSTALLATION	C	C03	(29)	(27)	(2)
7	CUSTOMER ACCOUNTING	C	C05	(74)	(69)	(5)
8	UNCOLLECTIBLES	C	C06	0	0	0
9	CUSTOMER SERVICE	C	C07	(5)	(5)	(0)
10	REVENUES	R	R99	0	0	0
11						
12	TOTAL REVENUE	R		0	0	0
13	TOTAL DEMAND	D		(976)	(868)	(108)
14	TOTAL COMMODITY	E		0	0	0
15	TOTAL CUSTOMER	C		(16,873)	(15,146)	(1,727)
16						
17	TOTAL			(17,849)	(16,014)	(1,835)
				=====	=====	=====

			TOTAL GAS SYSTEM (1)	TOTAL RESIDENTIAL (2)	TOTAL COMMERICAL (3)
FEDERAL INCOME TAX COMPUTATION					
1	GAS SUPPLY	E	0	0	0
2	DISTRIBUTION - DEMAND	D	(21,115)	(18,772)	(2,343)
3	DISTRIBUTION - CUSTOMER	C	(63,389)	(59,190)	(4,200)
4	SERVICES	C	(44,016)	(39,132)	(4,884)
5	METERS & HOUSE REGULATORS	C	(15,273)	(12,035)	(3,239)
6	CUSTOMER INSTALLATION	C	(3,026)	(2,825)	(200)
7	CUSTOMER ACCOUNTING	C	(10,932)	(10,197)	(736)
8	UNCOLLECTIBLES	C	(4,937)	(4,125)	(812)
9	CUSTOMER SERVICE	C	(820)	(765)	(54)
10	REVENUES	R	118,230	98,789	19,442
11					
12	TOTAL REVENUE	R	118,230	98,789	19,442
13	TOTAL DEMAND	D	(21,115)	(18,772)	(2,343)
14	TOTAL COMMODITY	E	0	0	0
15	TOTAL CUSTOMER	C	(142,393)	(128,268)	(14,124)
16					
17	TOTAL		(45,278)	(48,252)	2,974
			=====	=====	=====

	TOTAL GAS SYSTEM (1)	TOTAL RESIDENTIAL (2)	TOTAL COMMERICAL (3)
CUSTOMER COST BY CLASS			
1 NUMBER OF CUSTOMERS	1,170	1,092	78
2			
3 RATE BASE	1,203,795	1,077,334	126,461
4			
5 TOTAL CUSTOMER OPERATING EXPS	366,683	329,958	36,725
6 MONTHLY OP. EXPS. COST/CUST	26.12	25.17	39.49
7			
8 RETURN @ -2.42% (CUSTOMER)	(29,188)	(26,122)	(3,066)
9 F.I.T. PERCENT ON RETURN	136.83%		
10 INCOME TAX ON RETURN	(39,938)	(35,742)	(4,196)
11 TOTAL RETURN & F.I.T.	(69,126)	(61,864)	(7,262)
12 MONTHLY RET. F.I.T. COST/CUST	(4.92)	(4.72)	(7.81)
13			
14 MONTHLY CUSTOMER COSTS	21.20	20.45	31.68
	=====	=====	=====

			TOTAL GAS SYSTEM (1)	TOTAL RESIDENTIAL (2)	TOTAL COMMERICAL (3)
ALLOCATION FACTORS					
1	MAX. DEMAND 1 HR. NON-COINC.		775	689	86
2	PERCENT	D02	100.000000%	88.903226%	11.096774%
3					
4	ANNUAL GAS SALES TO CUSTOMERS		1,312,174	1,072,734	239,440
5	PERCENT	E01	100.000000%	81.752420%	18.247580%
6					
7	BOOK COST OF MAINS		737,163	688,323	48,840
8	PERCENT	C01	100.000000%	93.374600%	6.625400%
9					
10	BOOK COST - SERVICES		496,228	441,163	55,065
11	PERCENT	C02	100.000000%	88.903286%	11.096714%
12					
13	CUSTOMER INSTALLATION EXP.		5,965	5,570	395
14	PERCENT	C03	100.000000%	93.378039%	6.621961%
15					
16	BOOK COST OF METERS		231,782	182,634	49,148
17	PERCENT	C04	100.000000%	78.795592%	21.204408%
18					
19	CUSTOMER ACCOUNTING		25,756	24,023	1,733
20	PERCENT	C05	100.000000%	93.271471%	6.728529%
21					
22	UNCOLLECTIBLE ACCOUNTS		14,105	11,786	2,319
23	PERCENT	C06	100.000000%	83.559022%	16.440978%
24					
25	CUSTOMER SERVICE EXP.		1,999	1,867	132
26	PERCENT	C07	100.000000%	93.396698%	6.603302%
27					
28	REVENUES-WORKING CAPITAL		7,271	6,075	1,196
29	PERCENT	S01	100.000000%	83.551093%	16.448907%
30					
31	REVENUES-PAYROLL & MISC.		9,358	7,819	1,539
32	PERCENT	S02	100.000000%	83.554178%	16.445822%
33					
34	REVENUES		341,552	285,388	56,164
35	PERCENT	R01	100.000000%	83.556130%	16.443870%
36					
37	OTHER REVENUES		5,607	4,685	922
38	PERCENT	R02	100.000000%	83.556269%	16.443731%
39					
40	NULL REVENUE FACTOR	R99	0	0	0
41	PERCENT		0.000000%	0.000000%	0.000000%
42					
43	NUMBER OF CUSTOMERS	K01	1,170	1,092	78

EXHIBIT G-7
TABLE 1A

Pike County Light And Power Company
Gas Embedded Cost-of-Service Study Results
For the Year 2007

<u>Service Classification</u>	<u>Rate of Return</u>	<u>Initial Surplus/Deficiency*</u>	<u>Adjustment**</u>	<u>Adjusted Surplus/Deficiency*</u>
Total System	-2.42%			
Total Residential	-3.59%	(26,502)	4,014	(22,488)
Total Commercial	7.46%	22,488		22,488
Total System		(4,014)	4,014	0
			4,014	0

* Deficiencies shown as negative

** Applied to deficiency only

Pike County Light And Power Company
Index of Schedules
Gas Rate Design

Exhibit G-8

<u>Schedule</u>	<u>Title of Schedule</u>	<u>Witness</u>
(1)	Present and Proposed Rates (In Brief)	Rate Panel
(2)	Monthly Billing Comparisons	Rate Panel
(3)	Statements of Operating Revenues, Number of Customers and Annual Increases	Rate Panel

PIKE COUNTY LIGHT AND POWER COMPANY

Present and Proposed Rates (In Brief)

<u>Present SC1</u>		<u>Proposed SC1</u>	
Customer Charge	\$5.00	Customer Charge	\$6.29
All CCF @	1.2350 / CCF	All CCF @	1.5526 / CCF
Plus: STAS	-0.03%	Plus: STAS	0.00%
Plus: GCR*	0.14768 / CCF	Plus: GCR*	0.14768 / CCF
Minimum Charge: \$ 5 per month		Minimum Charge: \$ 6.29 per month	
<u>Present SC2</u>		<u>Proposed SC2</u>	
Customer Charge	\$5.00	Customer Charge	\$9.43
First 300 CCF @	1.3327 / CCF	First 300 CCF @	1.5115 / CCF
Over 300 CCF @	1.1971 / CCF	Over 300 CCF @	1.3577 / CCF
Plus: STAS	-0.03%	Plus: STAS	0.00%
Plus: GCR*	0.14768 / CCF	Plus: GCR*	0.14768 / CCF
Minimum Charge: \$ 5 per month		Minimum Charge: \$ 9.43 per month	

* GCR Rate is the average GCR rate for the Rate Year Period of April 2008 - March 2009. It is based on the GCR in effect from April 2008 to August 2008 and, for the period of September 2008 through March 2009, it is based on the GCR proposed by the Company in its July 2, 2008 preliminary GCR filing.

PIKE COUNTY LIGHT AND POWER COMPANY

Monthly Bill Comparison
Reflecting Proposed Rate Increase

<u>Monthly Usage (CCF)</u>	<u>Monthly Bill @ Present Rate</u>	<u>Monthly Bill @ Proposed Rate</u>	<u>Change</u>	<u>Percent Change</u>
Service Classification No. 1				
0	\$5.00	\$6.29	\$1.29	25.8%
3	9.15	11.39	2.24	24.5%
10	18.82	23.29	4.47	23.7%
30	46.47	57.29	10.83	23.3%
50	74.11	91.30	17.19	23.2%
100	143.23	176.31	33.08	23.1%
200	281.46	346.34	64.88	23.1%
300	419.69	516.37	96.68	23.0%
400	557.92	686.40	128.48	23.0%

Service Classification No. 2

0	\$5.00	\$9.43	\$4.43	88.6%
3	9.44	14.41	4.97	52.6%
10	19.80	26.02	6.22	31.4%
50	79.00	92.39	13.39	17.0%
100	153.00	175.35	22.35	14.6%
200	300.99	341.27	40.27	13.4%
250	374.99	424.23	49.23	13.1%
300	448.99	507.19	58.19	13.0%
400	583.43	657.72	74.29	12.7%
500	717.88	808.26	90.39	12.6%
750	1,053.98	1,184.61	130.63	12.4%
1,000	1,390.09	1,560.96	170.88	12.3%
2,000	2,734.51	3,066.36	331.85	12.1%
3,000	4,078.93	4,571.75	492.82	12.1%
4,000	5,423.35	6,077.15	653.80	12.1%

Included in the above bill calculations are:

	<u>Present</u>	<u>Proposed</u>
STAS	-0.03%	0.00%
GCR (\$/Ccf)*	0.14768	0.14768

* GCR Rate is the average GCR rate for the Rate Year Period of April 2008 - March 2009. It is based on the GCR in effect from April 2008 to August 2008 and, for the period of September 2008 through March 2009, it is based on the GCR proposed by the Company in its July 2, 2008 preliminary GCR filing.

PIKE COUNTY LIGHT AND POWER COMPANY

Statement of Revenues for the
Twelve Months Ending March 31, 2009
(At Current Rates)

<u>Customer Classification</u>	<u>Base Rate Revenue (\$)</u>	<u>Total Revenue (\$)</u>
SC1	1,480,591	1,627,822
SC2	<u>300,137</u>	<u>327,235</u>
Total	1,780,727	1,955,058

Note: Pike has other operating revenues of \$5,600.

Statement of Total Number of Customers
Served at March 31, 2009

SC1 Residential	1,084
SC2 Commercial	<u>76</u>
Total	<u>1,160</u>

PIKE COUNTY LIGHT AND POWER COMPANY

Tariff Regulations 52 Pa. Code § 53.52(b)(3) to (6)

53.52(b)(3) to (4) -- Statement of the number of gas customers whose bills will be increased and the annual increase in dollars.

<u>Customer Classification</u>	<u>Customers @ March 31, 2009</u>	<u>Annual Increase (\$)</u>
SC1 Residential	1,084	381,201
SC2 Commercial	<u>76</u>	<u>43,783</u>
Total	<u>1,160</u>	<u>424,985</u>

53.52(b)(5) to (6) -- Statement of the number of gas customers whose bills will be decreased and the annual decrease in dollars.

<u>Customer Classification</u>	<u>Customers @ March 31, 2009</u>	<u>Annual Decrease (\$)</u>
SC1 Residential	0	0
SC2 Commercial	<u>0</u>	<u>0</u>
Total	<u>0</u>	<u>0</u>

Pike County Light & Power Co.
Exhibit G-9 Cost of Equity

RAM Exhibit	Description	Pages
1	Resume of Roger A. Morin	20
2	Electric Utilities Beta Estimates	3
3	Electric Industry Historical Risk Premium	2
4	Distribution Utility Companies	5
5	S&P Distribution Electric Utilities - DCF Analysis: Value Line Growth Projections	2
6	S&P Distribution Electric Utilities - DCF Analysis: Analysts' Growth Forecasts	2
7	Moody's Electric Utilities - DCF Analysis: Value Line Growth Projections	4
8	Moody's Electric Utilities - DCF Analysis: Analysts' Growth Forecasts	3
Appendix A	CAPM, Empirical CAPM	15
Appendix B	Flotation Cost Allowance	9

RESUME OF ROGER A. MORIN

(Spring 2008)

NAME: Roger A. Morin

ADDRESS: 9 King Ave.
Jekyll Island, GA 31527, USA

87 Paddys Head Rd
Peggy's Cove Hway
Nova Scotia, Canada B3A 3N6

TELEPHONE: (912) 635-3233 business office
(912) 635-3233 business fax
(404) 229-2857 cellular
(902) 823-0000 summer office

E-MAIL ADDRESS: profmorin@mac.com

DATE OF BIRTH: 3/5/1945

PRESENT EMPLOYER: Georgia State University
Robinson College of Business
Atlanta, GA 30303

RANK: Emeritus Professor of Finance

HONORS: Professor of Finance for Regulated Industry
Director Center for the Study of Regulated Industry,
Robinson College of Business, Georgia State University.

EDUCATIONAL HISTORY

- Bachelor of Electrical Engineering, McGill University,
Montreal, Canada, 1967.
- Master of Business Administration, McGill University,
Montreal, Canada, 1969.
- PhD in Finance & Econometrics, Wharton School of Finance,
University of Pennsylvania, 1976.

EMPLOYMENT HISTORY

- Lecturer, Wharton School of Finance, Univ. of Pennsylvania, 1972-3
- Assistant Professor, University of Montreal School of Business, 1973-1976.
- Associate Professor, University of Montreal School of Business, 1976-1979.
- Professor of Finance, Georgia State University, 1979-2008
- Professor of Finance for Regulated Industry and Director, Center for the Study of Regulated Industry, Robinson College of Business, Georgia State University, 1985-2008
- Visiting Professor of Finance, Amos Tuck School of Business, Dartmouth College, Hanover, N.H., 1986
- Emeritus Professor of Finance, Georgia State University, 2007-8

OTHER BUSINESS ASSOCIATIONS

- Communications Engineer, Bell Canada, 1962-1967.
- Member of the Board of Directors, Financial Research Institute of Canada, 1974-1980.
- Co-founder and Director, Canadian Finance Research Foundation, 1977.
- Vice-President of Research, Garmaise-Thomson & Associates, Investment Management Consultants, 1980-1981.
- Executive Visions Inc., Board of Directors, Member.
- Board of External Advisors, College of Business, Georgia State University, Member 1987-1991.

PROFESSIONAL CLIENTS

AGL Resources
AT & T Communications
Alagasco - Energen
Alaska Anchorage Municipal Light & Power
Alberta Power Ltd.
Allete
Ameren
American Water Works Company
Ameritech
Arkansas Western Gas
Baltimore Gas & Electric – Constellation Energy
Bangor Hydro-Electric
B.C. Telephone
B C GAS
Bell Canada
Bellcore
Bell South Corp.
Bruncor (New Brunswick Telephone)
Burlington-Northern
C & S Bank
Cajun Electric
Canadian Radio-Television & Telecomm. Commission
Canadian Utilities
Canadian Western Natural Gas
Cascade Natural Gas
Centel
Centra Gas
Central Illinois Light & Power Co
Central Telephone

Central & South West Corp.
Chattanooga Gas Company
Cincinnati Gas & Electric
Cinergy Corp.
Citizens Utilities
City Gas of Florida
CN-CP Telecommunications
Commonwealth Telephone Co.
Columbia Gas System
Consolidated Natural Gas
Constellation Energy
Delmarva Power & Light Co
Deerpath Group
DTE Energy
Edison International
Edmonton Power Company
Elizabethtown Gas Co.
Emera
Energen
Engraph Corporation
Entergy Corp.
Entergy Arkansas Inc.
Entergy Gulf States, Inc.
Entergy Louisiana, Inc.
Entergy Mississippi Power
Entergy New Orleans, Inc.
First Energy
Florida Water Association
Fortis
Garmaise-Thomson & Assoc., Investment Consultants

Gaz Metropolitain
General Public Utilities
Georgia Broadcasting Corp.
Georgia Power Company
GTE California - Verizon
GTE Northwest Inc. - Verizon
GTE Service Corp. - Verizon
GTE Southwest Incorporated - Verizon
Gulf Power Company
Havasut Water Inc.
Hawaiian Electric Company
Hawaii Electric Light Company
Heater Utilities – Aqua - America
Hope Gas Inc.
Hydro-Quebec
ICG Utilities
Illinois Commerce Commission
Island Telephone
Jersey Central Power & Light
Kansas Power & Light
KeySpan Energy
Manitoba Hydro
Maritime Telephone
Maui Electric Company
Metropolitan Edison Co.
Minister of Natural Resources Province of Quebec
Minnesota Power & Light
Mississippi Power Company
Missouri Gas Energy
Mountain Bell

National Grid
Nevada Power Company
New Brunswick Power
Newfoundland Power Inc. - Fortis Inc.
New Market Hydro
New Tel Enterprises Ltd.
New York Telephone Co.
Niagara Mohawk Power Corp
Norfolk-Southern
Northeast Utilities
Northern Telephone Ltd.
Northwestern Bell
Northwestern Utilities Ltd.
Nova Scotia Power
Nova Scotia Utility and Review Board
NUI Corp.
NYNEX
Oklahoma G & E
Ontario Telephone Service Commission
Orange & Rockland
PNM Resources
Pacific Northwest Bell
People's Gas System Inc.
People's Natural Gas
Pennsylvania Electric Co.
Pepco Holdings
Potomac Electric Power Co.
Price Waterhouse
PSI Energy
Public Service Electric & Gas

Public Service of New Hampshire
Public Service of New Mexico
Puget Sound Electric Co.
Quebec Telephone
Regie de l'Energie du Quebec
Rochester Telephone
San Diego Gas & Electric
SaskPower
Sierra Pacific Power Company
Southern Bell
Southern States Utilities
Southern Union Gas
South Central Bell
Sun City Water Company
TECO Energy
The Southern Company
Touche Ross and Company
TransEnergie
Trans-Quebec & Maritimes Pipeline
TXU Corp
US WEST Communications
Union Heat Light & Power
Utah Power & Light
Vermont Gas Systems Inc.

MANAGEMENT DEVELOPMENT AND PROFESSIONAL EXECUTIVE EDUCATION

- Canadian Institute of Marketing, Corporate Finance, 1971-73
- Hydro-Quebec, "Capital Budgeting Under Uncertainty," 1974-75
- Institute of Certified Public Accountants, Mergers & Acquisitions, 1975-78

- Investment Dealers Association of Canada, 1977-78
 - Financial Research Foundation, bi-annual seminar, 1975-79
 - Advanced Management Research (AMR), faculty member, 1977-80
 - Financial Analysts Federation, Educational chapter: "Financial Futures Contracts" seminar
 - Exnet Inc. a.k.a. The Management Exchange Inc., faculty member 1981-2008.
- National Seminars:

Risk and Return on Capital Projects
Cost of Capital for Regulated Utilities
Capital Allocation for Utilities
Alternative Regulatory Frameworks
Utility Directors' Workshop
Shareholder Value Creation for Utilities
Fundamentals of Utility Finance in a Restructured Environment
Contemporary Issues in Utility Finance

- Georgia State University College of Business, Management Development Program, faculty member, 1981-1994.

EXPERT TESTIMONY & UTILITY CONSULTING AREAS OF EXPERTISE

Corporate Finance
Rate of Return
Capital Structure
Generic Cost of Capital
Costing Methodology
Depreciation
Flow-Through vs Normalization
Revenue Requirements Methodology
Utility Capital Expenditures Analysis
Risk Analysis
Capital Allocation
Divisional Cost of Capital, Unbundling
Incentive Regulation & Alternative Regulatory Plans
Shareholder Value Creation
Value-Based Management

REGULATORY BODIES

Alabama Public Service Commission
Alaska Public Utility Commission
Alberta Public Service Board
Arizona Corporation Commission
Arkansas Public Service Commission
British Columbia Board of Public Utilities
California Public Service Commission
Canadian Radio-Television & Telecommunications Comm.
Colorado Public Utilities Board
Delaware Public Utility Commission
District of Columbia Public Service Commission
Federal Communications Commission
Federal Energy Regulatory Commission
Florida Public Service Commission
Georgia Public Service Commission
Georgia Senate Committee on Regulated Industries
Hawaii Public Utilities Commission
Illinois Commerce Commission
Indiana Utility Regulatory Commission
Iowa Board of Public Utilities
Louisiana Public Service Commission
Maine Public Service Commission
Manitoba Board of Public Utilities
Michigan Public Service Commission
Minnesota Public Utilities Commission
Mississippi Public Service Commission
Missouri Public Service Commission
Montana Public Service Commission
National Energy Board of Canada

Nevada Public Service Commission
New Brunswick Board of Public Commissioners
New Hampshire Public Utility Commission
New Jersey Board of Public Utilities
New Mexico Public Regulatory Commission
New York Public Service Commission
Newfoundland Board of Commissioners of Public Utilities
North Carolina Utilities Commission
Ohio Public Utilities Commission
Oklahoma State Board of Equalization
Ontario Telephone Service Commission
Ontario Energy Board
Pennsylvania Public Service Commission
Quebec Natural Gas Board
Quebec Regie de l'Energie
Quebec Telephone Service Commission
South Carolina Public Service Commission
Tennessee Regulatory Authority
Texas Public Utility Commission
Utah Public Service Commission
Virginia Public Service Commission
Washington Utilities & Transportation Commission
West Virginia Public Service Commission

SERVICE AS EXPERT WITNESS

Southern Bell, So. Carolina PSC, Docket #81-201C
Southern Bell, So. Carolina PSC, Docket #82-294C
Southern Bell, North Carolina PSC, Docket #P-55-816
Metropolitan Edison, Pennsylvania PUC, Docket #R-822249
Pennsylvania Electric, Pennsylvania PUC, Docket #R-822250

Georgia Power, Georgia PSC, Docket # 3270-U, 1981
Georgia Power, Georgia PSC, Docket # 3397-U, 1983
Georgia Power, Georgia PSC, Docket # 3673-U, 1987
Georgia Power, F.E.R.C., Docket # ER 80-326, 80-327
Georgia Power, F.E.R.C., Docket # ER 81-730, 80-731
Georgia Power, F.E.R.C., Docket # ER 85-730, 85-731
Bell Canada, CRTC 1987
Northern Telephone, Ontario PSC
GTE-Quebec Telephone, Quebec PSC, Docket 84-052B
Newtel., Nfld. Brd of Public Commission PU 11-87
CN-CP Telecommunications, CRTC
Quebec Northern Telephone, Quebec PSC
Edmonton Power Company, Alberta Public Service Board
Kansas Power & Light, F.E.R.C., Docket # ER 83-418
NYNEX, FCC generic cost of capital Docket #84-800
Bell South, FCC generic cost of capital Docket #84-800
American Water Works - Tennessee, Docket #7226
Burlington-Northern - Oklahoma State Board of Taxes
Georgia Power, Georgia PSC, Docket # 3549-U
GTE Service Corp., FCC Docket #84-200
Mississippi Power Co., Miss. PSC, Docket U-4761
Citizens Utilities, Ariz. Corp. Comm., D # U2334-86020
Quebec Telephone, Quebec PSC, 1986, 1987, 1992
Newfoundland L & P, Nfld. Brd. Publ Comm. 1987, 1991
Northwestern Bell, Minnesota PSC, #P-421/CI-86-354
GTE Service Corp., FCC Docket #87-463
Anchorage Municipal Power & Light, Alaska PUC, 1988
New Brunswick Telephone, N.B. PUC, 1988
Trans-Quebec Maritime, Nat'l Energy Brd. of Cda, '88-92
Gulf Power Co., Florida PSC, Docket #88-1167-EI

Mountain States Bell, Montana PSC, #88-1.2
Mountain States Bell, Arizona CC, #E-1051-88-146
Georgia Power, Georgia PSC, Docket # 3840-U, 1989
Rochester Telephone, New York PSC, Docket # 89-C-022
Noverco - Gaz Metro, Quebec Natural Gas PSC, #R-3164-89
GTE Northwest, Washington UTC, #U-89-3031
Orange & Rockland, New York PSC, Case 89-E-175
Central Illinois Light Company, ICC, Case 90-0127
Peoples Natural Gas, Pennsylvania PSC, Case
Gulf Power, Florida PSC, Case # 891345-EI
ICG Utilities, Manitoba BPU, Case 1989
New Tel Enterprises, CRTC, Docket #90-15
Peoples Gas Systems, Florida PSC
Jersey Central Pwr & Light, N.J. PUB, Case ER 89110912J
Alabama Gas Co., Alabama PSC, Case 890001
Trans-Quebec Maritime Pipeline, Cdn. Nat'l Energy Board
Mountain Bell, Utah PSC,
Mountain Bell, Colorado PUB
South Central Bell, Louisiana PS
Hope Gas, West Virginia PSC
Vermont Gas Systems, Vermont PSC
Alberta Power Ltd., Alberta PUB
Ohio Utilities Company, Ohio PSC
Georgia Power Company, Georgia PSC
Sun City Water Company
Havas Water Inc.
Centra Gas (Manitoba) Co.
Central Telephone Co. Nevada
AGT Ltd., CRTC 1992
BC GAS, BCPUB 1992

California Water Association, California PUC 1992
Maritime Telephone 1993
BCE Enterprises, Bell Canada, 1993
Citizens Utilities Arizona gas division 1993
PSI Resources 1993-5
CILCORP gas division 1994
GTE Northwest Oregon 1993
Stentor Group 1994-5
Bell Canada 1994-1995
PSI Energy 1993, 1994, 1995, 1999
Cincinnati Gas & Electric 1994, 1996, 1999, 2004
Southern States Utilities, 1995
CILCO 1995, 1999, 2001
Commonwealth Telephone 1996
Edison International 1996, 1998
Citizens Utilities 1997
Stentor Companies 1997
Hydro-Quebec 1998
Entergy Gulf States Louisiana 1998, 1999, 2001, 2002, 2003
Detroit Edison, 1999, 2003
Entergy Gulf States, Texas, 2000, 2004
Hydro Quebec TransEnergie, 2001, 2004
Sierra Pacific Company, 2000, 2001, 2002, 2007
Nevada Power Company, 2001
Mid American Energy, 2001, 2002
Entergy Louisiana Inc. 2001, 2002, 2004
Mississippi Power Company, 2001, 2002, 2007
Oklahoma Gas & Electric Company, 2002 -2003
Public Service Electric & Gas, 2001, 2002
NUI Corp (Elizabethtown Gas Company), 2002

Jersey Central Power & Light, 2002
San Diego Gas & Electric, 2002
New Brunswick Power, 2002
Entergy New Orleans, 2002
Hydro-Quebec Distribution 2002
PSI Energy 2003
Fortis – Newfoundland Power & Light 2002
Emera – Nova Scotia Power 2004
Hydro-Quebec TransEnergie 2004
Hawaiian Electric 2004
Missouri Gas Energy 2004
AGL Resources 2004
Arkansas Western Gas 2004
Public Service of New Hampshire 2005
Hawaiian Electric Company 2005
Delmarva Power & Light Company 2005
Union Heat Power & Light 2005
Puget Sound Electric Co 2006
Cascade Natural Gas 2006
Entergy Arkansas 2006-7
Bangor Hydro 2006-7
Delmarva 2006-7
Potomac Electric Power Co. 2006, 2007
Detroit Edison Co. 2007
Nevada Power Co. 2007
Hawaiian Electric Co. 2006-7
Hawaii Electric Light Co. 2007
Maui Electric Co. 2007
Ameren Union Electric 2008
Consolidated Edison of New York 2007-2008

Orange & Rockland 2007
Niagara Mohawk Power Corp 2008
Allete (Minnesota Power) 2007-2008
Sierra Pacific Power 2007-2008

PROFESSIONAL AND LEARNED SOCIETIES

- Engineering Institute of Canada, 1967-1972
- Canada Council Award, recipient 1971 and 1972
- Canadian Association Administrative Sciences, 1973-80
- American Association of Decision Sciences, 1974-1978
- American Finance Association, 1975-2002
- Financial Management Association, 1978-2002

ACTIVITIES IN PROFESSIONAL ASSOCIATIONS AND MEETINGS

- Chairman of meeting on "New Developments in Utility Cost of Capital", Southern Finance Association, Atlanta, Nov. 1982
- Chairman of meeting on "Public Utility Rate of Return", Southeastern Public Utility Conference, Atlanta, Oct. 1982
- Chairman of meeting on "Current Issues in Regulatory Finance", Financial Management Association, Atlanta, Oct. 1983
- Chairman of meeting on "Utility Cost of Capital", Financial Management Association, Toronto, Canada, Oct. 1984.
- Committee on New Product Development, FMA, 1985
- Discussant, "Tobin's Q Ratio", paper presented at Financial Management Association, New York, N.Y., Oct. 1986
- Guest speaker, "Utility Capital Structure: New Developments", National Society of Rate of Return Analysts 18th Financial Forum, Wash., D.C. Oct. 1986
- Opening address, "Capital Expenditures Analysis: Methodology vs Mythology," Bellcore Economic Analysis Conference, Naples Fla., 1988.

- Guest speaker, "Mythodology in Regulatory Finance", Society of Utility Rate of Return Analysts (SURFA), Annual Conference, Wash., D.C. February 2007.

PAPERS PRESENTED:

"An Empirical Study of Multi-Period Asset Pricing," annual meeting of Financial Management Assoc., Las Vegas Nevada, 1987.

"Utility Capital Expenditures Analysis: Net Present Value vs Revenue Requirements", annual meeting of Financial Management Assoc., Denver, Colorado, October 1985.

"Intervention Analysis and the Dynamics of Market Efficiency", annual meeting of Financial Management Assoc., San Francisco, Oct. 1982

"Intertemporal Market-Line Theory: An Empirical Study," annual meeting of Eastern Finance Assoc., Newport, R.I. 1981

"Option Writing for Financial Institutions: A Cost-Benefit Analysis", 1979 annual meeting Financial Research Foundation

"Free-lunch on the Toronto Stock Exchange", annual meeting of Financial Research Foundation of Canada, 1978.

"Simulation System Computer Software SIMFIN", HP International Business Computer Users Group, London, 1975.

"Inflation Accounting: Implications for Financial Analysis." Institute of Certified Public Accountants Symposium, 1979.

OFFICES IN PROFESSIONAL ASSOCIATIONS

- President, International Hewlett-Packard Business Computers Users Group, 1977
- Chairman Program Committee, International HP Business Computers Users Group, London, England, 1975
- Program Coordinator, Canadian Assoc. of Administrative Sciences, 1976

- Member, New Product Development Committee, Financial Management Association, 1985-1986

- Reviewer: Journal of Financial Research

 - Financial Management

 - Financial Review

 - Journal of Finance

PUBLICATIONS

"Risk Aversion Revisited", Journal of Finance, Sept. 1983

"Hedging Regulatory Lag with Financial Futures," Journal of Finance, May 1983. (with G. Gay, R. Kolb)

"The Effect of CWIP on Cost of Capital," Public Utilities Fortnightly, July 1986.

"The Effect of CWIP on Revenue Requirements" Public Utilities Fortnightly, August 1986.

"Intervention Analysis and the Dynamics of Market Efficiency," Time-Series Applications, New York: North Holland, 1983. (with K. El-Sheshai)

"Market-Line Theory and the Canadian Equity Market," Journal of Business Administration, Jan. 1982, M. Brennan, editor

"Efficiency of Canadian Equity Markets," International Management Review, Feb. 1978.

"Intertemporal Market-Line Theory: An Empirical Test," Financial Review, Proceedings of the Eastern Finance Association, 1981.

BOOKS

Utilities' Cost of Capital, Public Utilities Reports Inc., Arlington, Va., 1984.

Regulatory Finance, Public Utilities Reports Inc., Arlington, Va., 2004

Driving Shareholder Value, McGraw-Hill, January 2001.

The New Regulatory Finance, Public Utilities Reports Inc., Arlington, Va., 2006.

MONOGRAPHS

Determining Cost of Capital for Regulated Industries, Public Utilities Reports, Inc., and The Management Exchange Inc., 1982 - 1993. (with V.L. Andrews)

Alternative Regulatory Frameworks, Public Utilities Reports, Inc., and The Management Exchange Inc., 1993. (with V.L. Andrews)

Risk and Return in Capital Projects, The Management Exchange Inc., 1980. (with B. Deschamps)

Utility Capital Expenditure Analysis, The Management Exchange Inc., 1983.

Regulation of Cable Television: An Econometric Planning Model, Quebec Department of Communications, 1978.

"An Economic & Financial Profile of the Canadian Cablevision Industry," Canadian Radio-Television & Telecommunication Commission (CRTC), 1978.

Computer Users' Manual: Finance and Investment Programs, University of Montreal Press, 1974, revised 1978.

Fiber Optics Communications: Economic Characteristics, Quebec Department of Communications, 1978.

"Canadian Equity Market Inefficiencies", Capital Market Research Memorandum, Garmaise & Thomson Investment Consultants, 1979.

MISCELLANEOUS CONSULTING REPORTS

"Operational Risk Analysis: California Water Utilities," Calif. Water Association, 1993.

"Cost of Capital Methodologies for Independent Telephone Systems", Ontario Telephone Service Commission, March 1989.

"The Effect of CWIP on Cost of Capital and Revenue Requirements", Georgia Power Company, 1985.

"Costing Methodology and the Effect of Alternate Depreciation and Costing Methods on Revenue Requirements and Utility Finances", Gaz Metropolitan Inc., 1985.

"Simulated Capital Structure of CN-CP Telecommunications: A Critique", CRTC, 1977.

"Telecommunications Cost Inquiry: Critique," CRTC, 1977.

"Social Rate of Discount in the Public Sector", CRTC Policy Statement, 1974.

"Technical Problems in Capital Projects Analysis", CRTC Policy Statement, 1974.

RESEARCH GRANTS

"Econometric Planning Model of the Cablevision Industry", International Institute of Quantitative Economics, CRTC.

"Application of the Averch-Johnson Model to Telecommunications Utilities", Canadian Radio-Television Commission. (CRTC)

"Economics of the Fiber Optics Industry", Quebec Dept. of Communications.

"Intervention Analysis and the Dynamics of Market Efficiency", Georgia State Univ. College of Business, 1981.

"Firm Size and Beta Stability", Georgia State University College of Business, 1982.

"Risk Aversion and the Demand for Risky Assets", Georgia State University College of Business, 1981.

Chase Econometrics, Interactive Data Corp., Research Grant, \$50,000 per annum, 1986-1989.

**S&P ELECTRIC DISTRIBUTION UTILITIES
BETA ESTIMATES**

Company Name	Beta
1 Amer. Elec. Power	0.85
2 Ameren Corp.	0.80
3 Consol. Edison	0.75
4 Energy East Corp.	0.75
5 Exelon Corp.	0.85
6 FirstEnergy Corp.	0.80
7 Northeast Utilities	0.75
8 NSTAR	0.80
9 Pepco Holdings	0.90
10 PPL Corp.	0.90
11 Public Serv. Enterprise	0.90
AVERAGE	0.82

Source: VLIA 06/2008

**MOODY'S ELECTRIC UTILITIES
BETA ESTIMATES**

Company Name	Beta
1 Amer. Elec. Power	0.85
2 CH Energy Group	0.90
3 Consol. Edison	0.75
4 Constellation Energy	0.90
5 Dominion Resources	0.80
6 DPL Inc.	0.80
7 DTE Energy	0.80
8 Duke Energy	N/A
9 Energy East Corp.	0.75
10 Exelon Corp.	0.85
11 FirstEnergy Corp.	0.80
12 IDACORP Inc.	0.90
13 NiSource Inc.	0.90
14 OGE Energy	0.90
15 PPL Corp.	0.90
16 Progress Energy	0.80
17 Public Serv. Enterprise	0.90
18 Southern Co.	0.70
19 TECO Energy	0.95
20 Xcel Energy Inc.	0.80
AVERAGE	0.84

Source: VLIA 06/2008

**MOODY'S ELECTRIC UTILITIES
BETA ESTIMATES**

Company Name	Beta
1 Amer. Elec. Power	0.85
2 Consol. Edison	0.75
3 DPL Inc.	0.80
4 DTE Energy	0.80
5 Duke Energy	N/A
6 Energy East Corp.	0.75
7 Exelon Corp.	0.85
8 FirstEnergy Corp.	0.80
9 IDACORP Inc.	0.90
10 PPL Corp.	0.90
11 Progress Energy	0.80
12 Public Serv. Enterprise	0.90
13 Southern Co.	0.70
14 TECO Energy	0.95
15 Xcel Energy Inc.	0.80
AVERAGE	0.83

Source: VLIA 06/2008

Electric Industry Historical Risk Premium

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
		Long-Term Government Bond	20 year Maturity Bond			Bond Total Return	Moody's Electric Utility Stock Index		Capital Gain/(Loss) % Growth		Stock Total Return	Equity Risk Premium Over Bond Returns	Equity Risk Premium Over Bond Yields
Line No.	Year	Yield	Value	Gain/Loss	Interest			Dividend		Yield			
1	1931	4.07%	1,000.00				43.23						
2	1932	3.15%	1,135.75	135.75	40.70	17.64%	39.42	2.22	-8.81%	5.14%	-3.68%	-21.32%	-6.83%
3	1933	3.36%	969.60	-30.40	31.50	0.11%	28.73	1.75	-27.12%	4.44%	-22.68%	-22.79%	-26.04%
4	1934	2.93%	1,064.73	64.73	33.60	9.83%	21.06	1.42	-26.70%	4.94%	-21.75%	-31.59%	-24.68%
5	1935	2.76%	1,025.99	25.99	29.30	5.53%	36.06	1.33	71.23%	6.32%	77.54%	72.01%	74.78%
6	1936	2.55%	1,032.74	32.74	27.60	6.03%	41.60	1.78	15.36%	4.94%	20.30%	14.27%	17.75%
7	1937	2.73%	972.40	-27.60	25.50	-0.21%	24.24	1.68	-41.73%	4.04%	-37.69%	-37.48%	-40.42%
8	1938	2.52%	1,032.83	32.83	27.30	6.01%	27.55	1.45	13.66%	5.98%	19.64%	13.62%	17.12%
9	1939	2.26%	1,041.65	41.65	25.20	6.68%	28.85	1.51	4.72%	5.48%	10.20%	3.51%	7.94%
10	1940	1.94%	1,052.84	52.84	22.60	7.54%	22.22	1.57	-22.98%	5.44%	-17.54%	-25.08%	-19.48%
11	1941	2.04%	983.64	-16.36	19.40	0.30%	13.45	1.27	-39.47%	5.72%	-33.75%	-34.06%	-35.79%
12	1942	2.46%	933.97	-66.03	20.40	-4.56%	14.29	1.28	6.25%	9.52%	15.76%	20.33%	13.30%
13	1943	2.48%	996.86	-3.14	24.60	2.15%	21.01	1.46	47.03%	10.22%	57.24%	55.10%	54.76%
14	1944	2.46%	1,003.14	3.14	24.80	2.79%	21.09	1.35	0.38%	6.43%	6.81%	4.01%	4.35%
15	1945	1.99%	1,077.23	77.23	24.60	10.18%	31.14	1.37	47.65%	6.50%	54.15%	43.97%	52.16%
16	1946	2.12%	978.90	-21.10	19.90	-0.12%	32.71	1.48	5.04%	4.75%	9.79%	9.91%	7.67%
17	1947	2.43%	951.13	-48.87	21.20	-2.77%	25.60	1.58	-21.74%	4.83%	-16.91%	-14.14%	-19.34%
18	1948	2.37%	1,009.51	9.51	24.30	3.38%	26.20	1.63	2.34%	6.37%	8.71%	5.33%	6.34%
19	1949	2.09%	1,045.58	45.58	23.70	6.93%	30.57	1.68	16.68%	6.41%	23.09%	16.16%	21.00%
20	1950	2.24%	975.93	-24.07	20.90	-0.32%	30.81	1.85	0.79%	6.05%	6.84%	7.15%	4.60%
21	1951	2.69%	930.75	-69.25	22.40	-4.69%	33.85	1.90	9.87%	6.17%	16.03%	20.72%	13.34%
22	1952	2.79%	984.75	-15.25	26.90	1.17%	37.85	1.92	11.82%	5.67%	17.49%	16.32%	14.70%
23	1953	2.74%	1,007.66	7.66	27.90	3.56%	39.61	2.09	4.65%	5.52%	10.17%	6.62%	7.43%
24	1954	2.72%	1,003.07	3.07	27.40	3.05%	47.56	2.14	20.07%	5.40%	25.47%	22.43%	22.75%
25	1955	2.95%	965.44	-34.56	27.20	-0.74%	49.35	2.27	3.76%	4.77%	8.54%	9.27%	5.59%
26	1956	3.45%	928.19	-71.81	29.50	-4.23%	48.96	2.37	-0.79%	4.80%	4.01%	8.24%	0.56%
27	1957	3.23%	1,032.23	32.23	34.50	6.67%	50.30	2.46	2.74%	5.02%	7.76%	1.09%	4.53%
28	1958	3.82%	918.01	-81.99	32.30	-4.97%	66.37	2.57	31.95%	5.11%	37.06%	42.03%	33.24%
29	1959	4.47%	914.65	-85.35	38.20	-4.71%	65.77	2.64	-0.90%	3.98%	3.07%	7.79%	-1.40%
30	1960	3.80%	1,093.27	93.27	44.70	13.80%	76.82	2.74	16.80%	4.17%	20.97%	7.17%	17.17%
31	1961	4.15%	952.75	-47.25	38.00	-0.92%	99.32	2.86	29.29%	3.72%	33.01%	33.94%	28.86%
32	1962	3.95%	1,027.48	27.48	41.50	6.90%	96.49	3.07	-2.85%	3.09%	0.24%	-6.66%	-3.71%
33	1963	4.17%	970.35	-29.65	39.50	0.99%	102.31	3.33	6.03%	3.45%	9.48%	8.50%	5.31%
34	1964	4.23%	991.96	-8.04	41.70	3.37%	115.54	3.68	12.93%	3.60%	16.53%	13.16%	12.30%
35	1965	4.50%	964.64	-35.36	42.30	0.69%	114.86	4.02	-0.59%	3.48%	2.89%	2.20%	-1.61%
36	1966	4.55%	993.48	-6.52	45.00	3.85%	105.99	4.18	-7.72%	3.64%	-4.08%	-7.93%	-8.63%
37	1967	5.56%	879.01	-120.99	45.50	-7.55%	98.19	4.44	-7.36%	4.19%	-3.17%	4.38%	-8.73%
38	1968	5.98%	951.38	-48.62	55.60	0.70%	104.04	4.58	5.96%	4.66%	10.62%	9.92%	4.64%
39	1969	6.87%	904.00	-96.00	59.80	-3.62%	84.62	4.63	-18.67%	4.45%	-14.22%	-10.60%	-21.09%
40	1970	6.48%	1,043.38	43.38	68.70	11.21%	88.59	4.73	4.69%	5.59%	10.28%	-0.93%	3.80%
41	1971	5.97%	1,059.09	59.09	64.80	12.39%	85.56	4.81	-3.42%	5.43%	2.01%	-10.38%	-3.96%
42	1972	5.99%	997.69	-2.31	59.70	5.74%	83.61	4.92	-2.28%	5.75%	3.47%	-2.27%	-2.52%
43	1973	7.26%	867.09	-132.91	59.90	-7.30%	60.87	5.04	-27.20%	6.03%	-21.17%	-13.87%	-28.43%
44	1974	7.60%	965.33	-34.67	72.60	3.79%	41.17	4.83	-32.36%	7.93%	-24.43%	-28.22%	-32.03%
45	1975	8.05%	955.63	-44.37	76.00	3.16%	55.66	4.99	35.20%	12.12%	47.32%	44.15%	39.27%
46	1976	7.21%	1,088.25	88.25	80.50	16.87%	66.29	5.25	19.10%	9.43%	28.53%	11.66%	21.32%
47	1977	8.03%	919.03	-80.97	72.10	-0.89%	68.19	5.68	2.87%	8.57%	11.43%	12.32%	3.40%
48	1978	8.98%	912.47	-87.53	80.30	-0.72%	59.75	5.98	-12.38%	8.77%	-3.61%	-2.88%	-12.59%
49	1979	10.12%	902.99	-97.01	89.80	-0.72%	56.41	6.34	-5.59%	10.61%	5.02%	5.74%	-5.10%
50	1980	11.99%	859.23	-140.77	101.20	-3.96%	54.42	6.67	-3.53%	11.82%	8.30%	12.25%	-3.69%

Electric Industry Historical Risk Premium

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
		Long-Term Government Bond	20 year Maturity Bond			Bond Total	Moody's Electric Utility Stock Index	Capital Gain/(Loss) %		Stock Total	Equity Risk Premium	Equity Risk Premium
Line No.	Year	Yield	Value	Gain/Loss	Interest	Return	Dividend	% Growth	Yield	Return	Over Bond Returns	Over Bond Yields
51	1981	13.34%	906.45	-93.55	119.90	2.63%	57.20	7.16	5.11%	13.16%	15.63%	4.93%
52	1982	10.95%	1,192.38	192.38	133.40	32.58%	70.26	7.64	22.83%	13.36%	3.61%	25.24%
53	1983	11.97%	923.12	-76.88	109.50	3.26%	72.03	8.00	2.52%	11.39%	10.64%	1.94%
54	1984	11.70%	1,020.70	20.70	119.70	14.04%	80.16	8.37	11.29%	11.62%	8.87%	11.21%
55	1985	9.56%	1,189.27	189.27	117.00	30.63%	94.98	8.71	18.49%	10.87%	-1.27%	19.79%
56	1986	7.89%	1,166.63	166.63	95.60	26.22%	113.66	8.97	19.67%	9.44%	2.89%	21.22%
57	1987	9.20%	881.17	-118.83	78.90	-3.99%	94.24	9.12	-17.09%	8.02%	-5.07%	-18.26%
58	1988	9.18%	1,001.82	1.82	92.00	9.38%	100.94	8.71	7.11%	9.24%	6.97%	7.17%
59	1989	8.16%	1,099.75	99.75	91.80	19.16%	122.52	8.85	21.38%	8.77%	10.99%	21.99%
60	1990	8.44%	973.17	-26.83	81.60	5.48%	117.77	8.76	-3.88%	7.15%	-2.20%	-5.17%
61	1991	7.30%	1,118.94	118.94	84.40	20.33%	144.02	9.02	22.29%	7.66%	9.61%	22.65%
62	1992	7.26%	1,004.19	4.19	73.00	7.72%	141.06	8.82	-2.06%	6.12%	-3.65%	-3.19%
63	1993	6.54%	1,079.70	79.70	72.60	15.23%	146.70	9.04	4.00%	6.41%	-4.82%	3.87%
64	1994	7.99%	856.40	-143.60	65.40	-7.82%	115.50	9.01	-21.27%	6.14%	-7.31%	-23.12%
65	1995	6.03%	1,225.98	225.98	79.90	30.59%	142.90	9.06	23.72%	7.84%	0.98%	25.54%
66	1996	6.73%	923.67	-76.33	60.30	-1.60%	136.00	9.06	-4.83%	6.34%	3.11%	-5.22%
67	1997	6.02%	1,081.92	81.92	67.30	14.92%	155.73	9.06	14.51%	6.66%	6.25%	15.15%
68	1998	5.42%	1,072.71	72.71	60.20	13.29%	181.84	8.01	16.77%	5.14%	8.62%	16.49%
69	1999	6.82%	848.41	-151.59	54.20	-9.74%	137.30	8.06	-24.49%	4.43%	-10.32%	-26.88%
70	2000	5.58%	1,148.30	148.30	68.20	21.65%	227.09	8.71	65.40%	6.34%	50.09%	66.16%
71	2001	5.75%	979.95	-20.05	55.80	3.57%	200.50	8.95	-11.71%	3.94%	-11.34%	-13.52%
72	2002	4.84%	1,115.77	115.77	57.50	17.33%	169.50	8.83	-15.46%	4.40%	-28.38%	-15.90%
73	2003	5.11%	966.42	-33.58	48.40	1.48%	201.21	8.52	18.71%	5.03%	22.25%	18.62%
74	2004	4.84%	1,034.35	34.35	51.10	8.54%	249.70	9.98	24.10%	4.96%	20.51%	24.22%
75	2005	4.61%	1,029.84	29.84	48.40	7.82%	285.86	10.72	14.48%	4.29%	10.95%	14.16%
76	2006	4.91%	962.06	-37.94	46.10	0.82%	326.19	11.31	14.11%	3.96%	17.25%	13.15%
78	Mean										5.7%	5.8%

Source: Mergent Public Utility Manual December stock prices and dividends

Dec. Bond yields from Morningstar (formerly Ibbotson Associates) 2008 Valuation Yearbook Table B-9 Long-Term Government Bonds Yields

Distribution Utility Companies	Parent
1 Atlanta Gas Light Co	AGL Resources Inc
2 Central Illinois Public Service Co.	Ameren
3 AEP Texas North Co	American Electric Power
4 AEP Texas Central Co.	American Electric Power
5 Ohio Power Co	American Electric Power
6 Columbus Southern Power Co.	American Electric Power
7 American States Water Co.	American States Water Company
8 Southern California Water Co.	American States Water Company
9 American Water Capital Corp	American Water Works Company Inc
10 Aqua Pennsylvania	Aqua America Inc
11 Aquarion Water Co. of Connecticut	Aquarion
12 California Water Service Co	California Water Service Group
13 Cascade Natural Gas Corp	Cascade Natural Gas Corp
14 CenterPoint Energy Houston Electric LLC	CenterPoint Energy
15 CenterPoint Energy Resources Corp.LLC	CenterPoint Energy
16 Central Hudson Gas & Electric Co.	CH Energy Group
17 Atlantic City Sewerage Co.	City of Atlantic City
18 Connecticut Water Co.	Connecticut Water Service Inc.
19 Connecticut Water Service Inc.	Connecticut Water Service Inc.
20 Consolidated Edison Inc.	Consolidated Edison
21 Orange and Rockland Utilities Inc.	Consolidated Edison
22 Consolidated Edison Co. of New York Inc.	Consolidated Edison
23 Baltimore Gas & Electric Co	Constellation Energy
24 Duquesne Light Holdings Inc.	Duquesne Light Holdings Inc.
25 Duquesne Light Co	Duquesne Light Holdings Inc.
26 Alabama Gas Corp.	Energen
27 Central Maine Power Co.	Energy East Corporation
28 Connecticut Natural Gas Corp.	Energy East Corporation
29 Southern Connecticut Gas Co.	Energy East Corporation
30 Commonwealth Edison Co.	Exelon
31 PECO Energy Co.	Exelon
32 Jersey Central Power & Light Co.	FirstEnergy
33 Metropolitan Edison Co.	FirstEnergy
34 Pennsylvania Electric Co.	FirstEnergy
35 Aquarion Co.	Kelda Group Plc
36 KeySpan Energy Delivery Long Island	KeySpan
37 KeySpan Energy Delivery New York	KeySpan
38 Boston Gas CO	KeySpan
39 Colonial Gas Co.	KeySpan
40 Laclede Group Inc.	Laclede
41 Laclede Gas Co.	Laclede
42 Middlesex Water Co	Middlesex Water Co
43 Niagara Mohawk Power Corp.	National Grid
44 Narragansett Electric Co.	National Grid
45 National Grid USA	National Grid USA

Distribution Utility Companies	Parent
46 Massachusetts Electric Co.	New England Electric Systems
47 New Jersey Natural Gas Co	New Jersey Resources
48 Nicor Gas Co.	Nicor Inc
49 Nicor Inc	Nicor Inc
50 Bay State Gas Co.	NiSource
51 Yankee Gas Services Co.	Northeast Utilities
52 Western Massachusetts Electric Co	Northeast Utilities System
53 Connecticut Light & Power Co.	Northeast Utilities System
54 Northwest Natural Gas Co.	Northwest Natural Gas Co.
55 NSTAR	NSTAR
56 Boston Edison Co.	NSTAR
57 Commonwealth Electric Co	NSTAR
58 NSTAR Gas Co.	NSTAR
59 Cambridge Electric Light Co.	NSTAR
60 ONEOK Inc.	ONEOK Inc.
61 Rockland Electric Co	Orange and Rockland Utilities Inc.
62 Peoples Gas Light & Coke Co.	Peoples Energy
63 North Shore Gas Co.	Peoples Energy
64 Delmarva Power & Light Co	PEPCO Holdings
65 Atlantic City Electric Co.	PEPCO Holdings
66 Potomac Electric Power Co.	PEPCO Holdings
67 Piedmont Natural Gas Co. Inc.	Piedmont Natural Gas
68 PPL Electric Utilities Corp.	PPL Corp
69 Baton Rouge Water Works Co. (The)	Private
70 Public Service Electric & Gas Co	Public Service Enterprise Group
71 Questar Gas Co	Questar
72 Public Service Co. of North Carolina Inc.	SCANA Corp.
73 Southern California Gas Co	Sempra Energy
74 South Jersey Gas Co	South Jersey Industries
75 Southern Union Co	Southern Union
76 Southwest Gas Corp.	Southwest Gas
77 Elizabethtown Water Co	Thames Water Co
78 TXU Gas Co.	TXU
79 Oncor Electric Delivery Co.	TXU
80 UGI Utilities Inc	UGI
81 United Water New Jersey	United Water Resources
82 United Waterworks	United Water Resources
83 Indiana Gas Co. Inc.	Vectren
84 WGL Holdings Inc.	WGL Holdings
85 Washington Gas Light Co.	WGL Holdings
86 Wisconsin Gas Co.	Wisconsin Energy Corp
87 York Water Co. (The)	York Water Co. (The)

Source: Standard & Poor's "New Business Profile Scores Assigned for U.S. Utility and Power Companies; Financial Guidelines Revised," June 2004

	Electricity Distribution Companies	Parent
1	Central Illinois Public Service Co.	Ameren
2	AEP Texas North Co	American Electric Power
3	AEP Texas Central Co.	American Electric Power
4	Ohio Power Co	American Electric Power
5	Columbus Southem Power Co.	American Electric Power
6	CenterPoint Energy Houston Electric	CenterPoint Energy
7	CenterPoint Energy Resources Corp	CenterPoint Energy
8	Central Hudson Gas & Electric Co.	CH Energy Group
9	Consolidated Edison Inc.	Consolidated Edison
10	Orange and Rockland Utilities Inc.	Consolidated Edison
11	Consolidated Edison Co. of New York	Consolidated Edison
12	Baltimore Gas & Electric Co	Constellation Energy
13	Duquesne Light Holdings Inc.	Duquesne Light Holdings Inc.
14	Duquesne Light Co	Duquesne Light Holdings Inc.
15	Central Maine Power Co.	Energy East Corporation
16	Connecticut Natural Gas Corp.	Energy East Corporation
17	Southern Connecticut Gas Co.	Energy East Corporation
18	Commonwealth Edison Co.	Exelon
19	PECO Energy Co.	Exelon
20	Jersey Central Power & Light Co.	FirstEnergy
21	Metropolitan Edison Co	FirstEnergy
22	Pennsylvania Electric Co.	FirstEnergy
23	Western Massachusetts Electric Co	Northeast Utilities
24	Connecticut Light & Power Co.	Northeast Utilities
25	NSTAR	NSTAR
26	Boston Edison Co.	NSTAR
27	Commonwealth Electric Co	NSTAR
28	NSTAR Gas Co.	NSTAR
29	Cambridge Electric Light Co.	NSTAR
30	Delmarva Power & Light Co	PEPCO Holdings
31	Atlantic City Electric Co.	PEPCO Holdings
32	Potomac Electric Power Co.	PEPCO Holdings
33	PPL Electric Utilities Corp.	PPL Corp
34	Public Service Electric & Gas Co	Public Service Enterprise Group
35	Public Service Co. of North Carolina Inc.	SCANA Corp.
36	Oncor Electric Delivery Co.	TXU

Source: Standard & Poor's "New Business Profile Scores Assigned for U.S. Utility and Power Companies; Financial Guidelines Revised," June 2004

Parent of Electricity Distribution Companies		% Elec Reg Rev
1	Ameren	83
2	American Electric Power	89
3	CenterPoint Energy	17
4	CH Energy Group	48
5	Consolidated Edison	62
6	Constellation Energy	13
7	Duquesne Light Holdings Inc.	na
8	Energy East Corporation	56
9	Exelon	56
10	FirstEnergy	88
11	Northeast Utilities	84
12	NSTAR	78
13	PEPCO Holdings	56
14	PPL Corp	62
15	Public Service Enterprise Group	66
16	SCANA Corp.	42
17	TXU	na

Source: AUS Utility Reports June 2008

Parent of Electricity Distribution Companies

		% Elec Reg Rev
1	Ameren	83
2	American Electric Power	89
3	Consolidated Edison	62
4	Energy East Corporation	56
5	Exelon	56
6	FirstEnergy	88
7	Northeast Utilities	84
8	NSTAR	78
9	PEPCO Holdings	56
10	PPL Corp	62
11	Public Service Enterprise Group	66
	AVERAGE	71

Companies < 50% Regul Rev:

Centerpoint, CH Energy, Constellation, SCANA.
TXU, Duquesne n.a.

S&P 's DISTRIBUTION ELECTRIC UTILITIES
DCF ANALYSIS: VALUE LINE GROWTH PROJECTIONS

Company	% Current Divid Yield	Proj EPS Growth	% Expected Divid Yield	Cost of Equity	ROE
	(1)	(2)	(3)	(4)	(5)
1 Amer. Elec. Power	3.9	6.0	4.2	10.2	10.4
2 Ameren Corp.	5.5	3.5	5.7	9.2	9.5
3 Consol. Edison	5.7	2.0	5.8	7.8	8.1
4 Energy East Corp.	5.0	-0.5	4.9	4.4	4.7
5 Exelon Corp.	2.3	9.0	2.5	11.5	11.6
6 FirstEnergy Corp.	2.9	11.0	3.2	14.2	14.4
7 Northeast Utilities	3.3	13.5	3.7	17.2	17.4
8 NSTAR	4.3	7.5	4.6	12.1	12.4
9 Pepco Holdings	4.0	13.0	4.5	17.5	17.7
10 PPL Corp.	2.8	14.0	3.2	17.2	17.3
11 Public Serv. Enterprise	3.0	10.0	3.3	13.3	13.5
AVERAGE	3.9	8.1	4.1	12.2	12.5
MEDIAN					12.4

Notes:

Column 1, 2: Value Line Investment Analyzer, 06/2008

Column 3 = Column 1 times (1 + Column 2/100)

Column 4 = Column 3 + Column 2

Column 5 = (Column 3 /0.95) + Column 2

S&P 's DISTRIBUTION ELECTRIC UTILITIES
DCF ANALYSIS: VALUE LINE GROWTH PROJECTIONS

Company	% Current Divid Yield (1)	Proj DPS Growth (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1 Amer. Elec. Power	3.9	7.5	4.2	11.7	12.0
2 Ameren Corp.	5.5	-	5.5	5.5	5.8
3 Consol. Edison	5.7	1.0	5.7	6.7	7.0
4 Energy East Corp.	5.0	2.0	5.0	7.0	7.3
5 Exelon Corp.	2.3	6.0	2.4	8.4	8.5
6 FirstEnergy Corp.	2.9	8.5	3.1	11.6	11.8
7 Northeast Utilities	3.3	6.0	3.4	9.4	9.6
8 NSTAR	4.3	7.0	4.6	11.6	11.9
9 Pepco Holdings	4.0	10.0	4.4	14.4	14.6
10 PPL Corp.	2.8	14.0	3.2	17.2	17.3
11 Public Serv. Enterprise	3.0	6.5	3.2	9.7	9.9
AVERAGE	3.9	6.2	4.1	10.3	10.5
AVERAGE w/o Ameren					11.0

Notes:

Column 1, 2: Value Line Investment Analyzer, 06/2008

Column 3 = Column 1 times (1 + Column 2/100)

Column 4 = Column 3 + Column 2

Column 5 = (Column 3 /0.95) + Column 2

DCF ANALYSIS ANALYSTS' GROWTH PROJECTIONS

	Company	% Current Divid Yield (1)	Proj EPS Growth (2)
1	Amer. Elec. Power	3.9	5.4
2	Ameren Corp.	5.5	5.0
3	Consol. Edison	5.7	3.2
4	Energy East Corp.	5.0	N/A
5	Exelon Corp.	2.3	11.5
6	FirstEnergy Corp.	2.9	6.5
7	Northeast Utilities	3.3	10.0
8	NSTAR	4.3	6.4
9	Pepco Holdings	4.0	9.6
10	PPL Corp.	2.8	16.3
11	Public Serv. Enterprise	3.0	14.3

Notes:

Column 1: Value Line Investment Analyzer, 06/2008

Column 2: Zacks 06/2008

No growth projection available for Energy East

S&P'S DISTRIBUTION ELECTRIC UTILITIES
DCF ANALYSIS: ANALYSTS' GROWTH FORECASTS

	Company	% Current Divid Yield	Proj EPS Growth	% Expected Divid Yield	Cost of Equity	ROE
		(1)	(2)	(3)	(4)	(5)
1	Amer. Elec. Power	3.9	5.4	4.2	9.6	9.8
2	Ameren Corp.	5.5	5.0	5.8	10.8	11.1
3	Consol. Edison	5.7	3.2	5.9	9.0	9.3
4	Exelon Corp.	2.3	11.5	2.5	14.0	14.2
5	FirstEnergy Corp.	2.9	6.5	3.1	9.6	9.7
6	Northeast Utilities	3.3	10.0	3.6	13.6	13.8
7	NSTAR	4.3	6.4	4.6	11.0	11.2
8	Pepco Holdings	4.0	9.6	4.4	14.0	14.2
9	PPL Corp.	2.8	16.3	3.2	19.5	19.6
10	Public Serv. Enterprise	3.0	14.3	3.4	17.8	17.9
	AVERAGE	3.8	8.8	4.1	12.9	13.1
	MEDIAN w/o PPL					11.2

Notes:

Column 1: Value Line Investment Analyzer, 06/2008

Column 2: Zacks long-term earnings growth forecast, 06/2008

Column 3 = Column 1 times (1 + Column 2/100)

Column 4 = Column 3 + Column 2

Column 5 = (Column 3 / 0.95) + Column 2

MOODY'S ELECTRIC UTILITIES

DCF ANALYSIS: VALUE LINE GROWTH PROJECTION

Company	% Current Divid Yield (1)	Proj EPS Growth (2)
1 Amer. Elec. Power	3.9	6.0
2 CH Energy Group	5.7	2.0
3 Consol. Edison	5.7	2.0
4 Constellation Energy	2.3	13.0
5 Dominion Resources	3.7	12.0
6 DPL Inc.	3.9	11.0
7 DTE Energy	4.8	4.5
8 Duke Energy	5.0	N/A
9 Energy East Corp.	5.0	-0.5
10 Exelon Corp.	2.3	9.0
11 FirstEnergy Corp.	2.9	11.0
12 IDACORP Inc.	3.9	3.0
13 NiSource Inc.	5.1	5.0
14 OGE Energy	4.2	4.5
15 PPL Corp.	2.8	14.0
16 Progress Energy	5.8	5.0
17 Public Serv. Enterprise	3.0	10.0
18 Southern Co.	4.7	5.5
19 TECO Energy	3.9	4.5
20 Xcel Energy Inc.	4.5	7.5

Notes:

Column 1, 2: Value Line Investment Analyzer, 6/2008

No growth forecast available for Duke Energy

MOODY'S ELECTRIC UTILITIES
DCF ANALYSIS: VALUE LINE GROWTH PROJECTIONS

Company	% Current Divid Yield (1)	Proj EPS Growth (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1 Amer. Elec. Power	3.9	6.0	4.2	10.2	10.4
2 CH Energy Group	5.7	2.0	5.8	7.8	8.1
3 Consol. Edison	5.7	2.0	5.8	7.8	8.1
4 Constellation Energy	2.3	13.0	2.6	15.6	15.7
5 Dominion Resources	3.7	12.0	4.2	16.2	16.4
6 DPL Inc.	3.9	11.0	4.4	15.4	15.6
7 DTE Energy	4.8	4.5	5.0	9.5	9.7
8 Energy East Corp.	5.0	-0.5	4.9	4.4	4.7
9 Exelon Corp.	2.3	9.0	2.5	11.5	11.6
10 FirstEnergy Corp.	2.9	11.0	3.2	14.2	14.4
11 IDACORP Inc.	3.9	3.0	4.0	7.0	7.2
12 NiSource Inc.	5.1	5.0	5.3	10.3	10.6
13 OGE Energy	4.2	4.5	4.4	8.9	9.1
14 PPL Corp.	2.8	14.0	3.2	17.2	17.3
15 Progress Energy	5.8	5.0	6.1	11.1	11.4
16 Public Serv. Enterprise	3.0	10.0	3.3	13.3	13.5
17 Southern Co.	4.7	5.5	4.9	10.4	10.7
18 TECO Energy	3.9	4.5	4.1	8.6	8.8
19 Xcel Energy Inc.	4.5	7.5	4.8	12.3	12.6
AVERAGE	4.1	6.8	4.4	11.1	11.4

Notes:

Column 1, 2: Value Line Investment Analyzer, 6/2008

Column 3 = Column 1 times (1 + Column 2/100)

Column 4 = Column 3 + Column 2

Column 5 = (Column 3 / 0.95) + Column 2

MOODY'S ELECTRIC UTILITIES
DCF ANALYSIS: VALUE LINE GROWTH PROJECTIONS

Company	% Current Divid Yield (1)	Proj EPS Growth (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1 Amer. Elec. Power	3.9	6.0	4.2	10.2	10.4
2 Consol. Edison	5.7	2.0	5.8	7.8	8.1
3 DPL Inc.	3.9	11.0	4.4	15.4	15.6
4 DTE Energy	4.8	4.5	5.0	9.5	9.7
5 Energy East Corp.	5.0	-0.5	4.9	4.4	4.7
6 Exelon Corp.	2.3	9.0	2.5	11.5	11.6
7 FirstEnergy Corp.	2.9	11.0	3.2	14.2	14.4
8 IDACORP Inc.	3.9	3.0	4.0	7.0	7.2
9 PPL Corp.	2.8	14.0	3.2	17.2	17.3
10 Progress Energy	5.8	5.0	6.1	11.1	11.4
11 Public Serv. Enterprise	3.0	10.0	3.3	13.3	13.5
12 Southern Co.	4.7	5.5	4.9	10.4	10.7
13 TECO Energy	3.9	4.5	4.1	8.6	8.8
14 Xcel Energy Inc.	4.5	7.5	4.8	12.3	12.6
AVERAGE	4.1	6.6	4.3	10.9	11.1

Notes:

Column 1, 2: Value Line Investment Analyzer, 6/2008

Column 3 = Column 1 times (1 + Column 2/100)

Column 4 = Column 3 + Column 2

Column 5 = (Column 3 / 0.95) + Column 2

No earnings growth forecast for Duke Energy.

MOODY'S ELECTRIC UTILITIES
DCF ANALYSIS: VALUE LINE GROWTH PROJECTIONS

Company	% Current Divid Yield (1)	Proj DPS Growth (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1 Amer. Elec. Power	3.9	7.5	4.2	11.7	12.0
2 Consol. Edison	5.7	1.0	5.7	6.7	7.0
3 DPL Inc.	3.9	5.0	4.1	9.1	9.3
4 DTE Energy	4.8	1.5	4.8	6.3	6.6
5 Energy East Corp.	5.0	2.0	5.0	7.0	7.3
6 Exelon Corp.	2.3	6.0	2.4	8.4	8.5
7 FirstEnergy Corp.	2.9	8.5	3.1	11.6	11.8
8 PPL Corp.	2.8	14.0	3.2	17.2	17.3
9 Progress Energy	5.8	1.0	5.9	6.9	7.2
10 Public Serv. Enterprise	3.0	6.5	3.2	9.7	9.9
11 Southern Co.	4.7	4.5	4.9	9.4	9.6
12 TECO Energy	3.9	2.5	4.0	6.5	6.7
13 Xcel Energy Inc.	4.5	4.5	4.7	9.2	9.5
AVERAGE	4.1	5.0	4.3	9.2	9.4

Notes:

Column 1, 2: Value Line Investment Analyzer, 6/2008

Column 3 = Column 1 times (1 + Column 2/100)

Column 4 = Column 3 + Column 2

Column 5 = (Column 3 / 0.95) + Column 2

No dividend growth forecast available for Duke Energy and IDACORP

MOODY'S ELECTRIC UTILITIES

DCF ANALYSIS: ANALYSTS' GROWTH FORECASTS

Company	% Current Divid Yield (1)	Analysts' Growth Forecast (2)
1 Amer. Elec. Power	3.9	5.4
2 CH Energy Group	5.7	N/A
3 Consol. Edison	5.7	3.2
4 Constellation Energy	2.3	18.0
5 Dominion Resources	3.7	10.3
6 DPL Inc.	3.9	10.7
7 DTE Energy	4.8	6.3
8 Duke Energy	5.0	5.8
9 Energy East Corp.	5.0	N/A
10 Exelon Corp.	2.3	11.5
11 FirstEnergy Corp.	2.9	6.5
12 IDACORP Inc.	3.9	6.0
13 NiSource Inc.	5.1	3.0
14 OGE Energy	4.2	4.0
15 PPL Corp.	2.8	16.3
16 Progress Energy	5.8	4.7
17 Public Serv. Enterprise	3.0	14.3
18 Southern Co.	4.7	4.7
19 TECO Energy	3.9	8.8
20 Xcel Energy Inc.	4.5	5.4

Notes:

Column 1: Value Line Investment Analyzer, 6/2008

Column 2: Zacks long-term earnings growth forecast, 06/2008

No growth forecast available for CH Energy Group, Energy East.

MOODY'S ELECTRIC UTILITIES
DCF ANALYSIS: ANALYSTS' GROWTH FORECASTS

Company	% Current Divid Yield (1)	Analysts' Growth Forecast (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1 Amer. Elec. Power	3.9	5.4	4.2	9.6	9.8
2 Consol. Edison	5.7	3.2	5.9	9.0	9.3
3 Constellation Energy	2.3	18.0	2.7	20.7	20.9
4 Dominion Resources	3.7	10.3	4.1	14.5	14.7
5 DPL Inc.	3.9	10.7	4.3	15.0	15.2
6 DTE Energy	4.8	6.3	5.1	11.4	11.7
7 Duke Energy	5.0	5.8	5.3	11.1	11.4
8 Exelon Corp.	2.3	11.5	2.5	14.0	14.2
9 FirstEnergy Corp.	2.9	6.5	3.1	9.6	9.7
10 IDACORP Inc.	3.9	6.0	4.1	10.1	10.3
11 NiSource Inc.	5.1	3.0	5.2	8.2	8.5
12 OGE Energy	4.2	4.0	4.4	8.4	8.6
13 PPL Corp.	2.8	16.3	3.2	19.5	19.6
14 Progress Energy	5.8	4.7	6.1	10.8	11.1
15 Public Serv. Enterprise	3.0	14.3	3.4	17.8	17.9
16 Southern Co.	4.7	4.7	4.9	9.6	9.9
17 TECO Energy	3.9	8.8	4.3	13.0	13.2
18 Xcel Energy Inc.	4.5	5.4	4.8	10.2	10.4
AVERAGE	4.0	8.0	4.3	12.4	12.6

Notes:

Column 1: Value Line Investment Analyzer, 6/2008

Column 2: Zacks long-term earnings growth forecast, 06/2008

Column 3 = Column 1 times (1 + Column 2/100)

Column 4 = Column 3 + Column 2

Column 5 = (Column 3 / 0.95) + Column 2

MOODY'S ELECTRIC UTILITIES
DCF ANALYSIS: ANALYSTS' GROWTH FORECASTS

Company	% Current Divid Yield (1)	Analysts' Growth Forecast (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1 Amer. Elec. Power	3.9	5.4	4.2	9.6	9.8
2 Consol. Edison	5.7	3.2	5.9	9.0	9.3
3 DPL Inc.	3.9	10.7	4.3	15.0	15.2
4 DTE Energy	4.8	6.3	5.1	11.4	11.7
5 Duke Energy	5.0	5.8	5.3	11.1	11.4
7 Exelon Corp.	2.3	11.5	2.5	14.0	14.2
8 FirstEnergy Corp.	2.9	6.5	3.1	9.6	9.7
9 IDACORP Inc.	3.9	6.0	4.1	10.1	10.3
10 PPL Corp.	2.8	16.3	3.2	19.5	19.6
11 Progress Energy	5.8	4.7	6.1	10.8	11.1
12 Public Serv. Enterprise	3.0	14.3	3.4	17.8	17.9
13 Southern Co.	4.7	4.7	4.9	9.6	9.9
14 TECO Energy	3.9	8.8	4.3	13.0	13.2
15 Xcel Energy Inc.	4.5	5.4	4.8	10.2	10.4
AVERAGE	4.1	7.8	4.4	12.2	12.4
MEDIAN					11.3

Notes:

Column 1: Value Line Investment Analyzer, 6/2008

Column 2: Zacks long-term earnings growth forecast, 6/2008

Column 3 = Column 1 times (1 + Column 2/100)

Column 4 = Column 3 + Column 2

Column 5 = (Column 3 / 0.95) + Column 2

No growth forecast available for Energy East

APPENDIX A

CAPM, EMPIRICAL CAPM

The Capital Asset Pricing Model (CAPM) is a fundamental paradigm of finance. Simply put, the fundamental idea underlying the CAPM is that risk-averse investors demand higher returns for assuming additional risk, and higher-risk securities are priced to yield higher expected returns than lower-risk securities. The CAPM quantifies the additional return, or risk premium, required for bearing incremental risk. It provides a formal risk-return relationship anchored on the basic idea that only market risk matters, as measured by beta. According to the CAPM, securities are priced such that their:

$$\text{EXPECTED RETURN} = \text{RISK-FREE RATE} + \text{RISK PREMIUM}$$

Denoting the risk-free rate by R_F and the return on the market as a whole by R_M , the CAPM is:

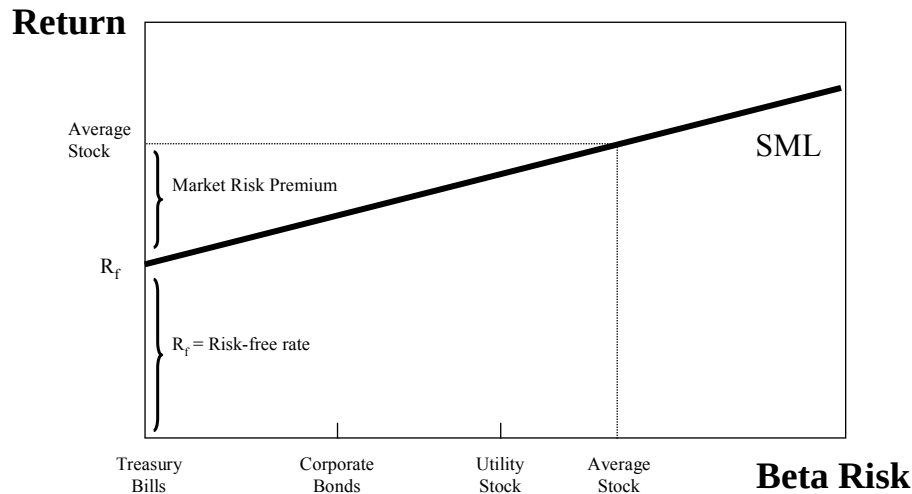
$$K = R_F + \beta(R_M - R_F) \quad (1)$$

Equation 1 is the CAPM expression which asserts that an investor expects to earn a return, K , that could be gained on a risk-free investment, R_F , plus a risk premium for assuming risk, proportional to the security's market risk, also known as beta, β , and the market risk premium, $(R_M - R_F)$, where R_M is the market return. The market risk premium $(R_M - R_F)$ can be abbreviated MRP so that the CAPM becomes:

$$K = R_F + \beta \times \text{MRP} \quad (2)$$

The CAPM risk-return relationship is depicted in the figure below and is typically labeled as the Security Market Line (SML) by the investment community.

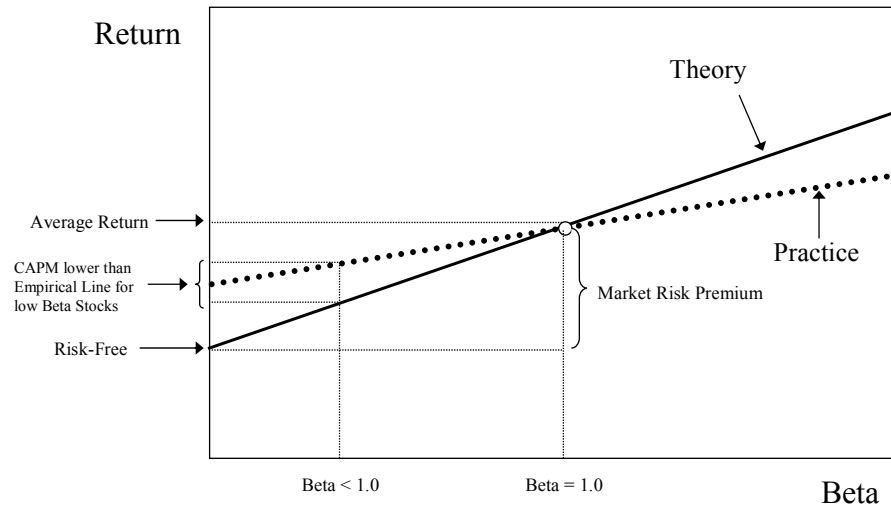
CAPM and Risk - Return in Capital Markets



A myriad empirical tests of the CAPM have shown that the risk-return tradeoff is not as steeply sloped as that predicted by the CAPM, however. That is, low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. In other words, the CAPM tends to overstate the actual sensitivity of the cost of capital to beta: low-beta stocks tend to have higher returns and high-beta stocks tend to have lower risk returns than predicted by the CAPM. The difference between the CAPM and the type of relationship observed in the empirical studies is depicted in the figure below. This is one of the most widely known empirical findings of the finance literature. This extensive literature is summarized in Chapter 13 of Dr. Morin's book [Regulatory Finance, Public Utilities Report Inc., Arlington, VA, 1994].

Risk vs Return

Theory vs. Practice



A number of refinements and expanded versions of the original CAPM theory have been proposed to explain the empirical findings. These revised CAPMs typically produce a risk-return relationship that is flatter than the standard CAPM prediction. The following equation makes use of these empirical findings by flattening the slope of the risk-return relationship and increasing the intercept:

$$K = R_F + \alpha + \beta (MRP - \alpha) \quad (3)$$

where α is the "alpha" of the risk-return line, a constant determined empirically, and the other symbols are defined as before. Alternatively, Equation 3 can be written as follows:

$$K = R_F + a MRP + (1-a) \beta MRP \quad (4)$$

where a is a fraction to be determined empirically. Comparing Equations 3 and 4, it is easy to see that alpha equals 'a' times MRP, that is, $\alpha = a \times MRP$

Theoretical Underpinnings

The obvious question becomes what would produce a risk return relationship which is flatter than the CAPM prediction, or in other words, how do you explain the presence of “alpha” in the above equation. The exclusion of variables aside from beta would produce this result. Three such variables are noteworthy: dividend yield, skewness, and hedging potential.

The dividend yield effects stem from the differential taxation on corporate dividends and capital gains. The standard CAPM does not consider the regularity of dividends received by investors. Utilities generally maintain high dividend payout ratios relative to the market, and by ignoring dividend yield, the CAPM provides biased cost of capital estimates. To the extent that dividend income is taxed at a higher rate than capital gains, investors will require higher pre-tax returns in order to equalize the after-tax returns provided by high-yielding stocks (e.g. utility stocks) with those of low-yielding stocks. In other words, high-yielding stocks must offer investors higher pre-tax returns. Even if dividends and capital gains are undifferentiated for tax purposes, there is still a tax bias in favor of earnings retention (lower dividend payout), as capital gains taxes are paid only when gains are realized.

Empirical studies by Litzenberger and Ramaswamy (1979) and Litzenberger et al. (1980) find that security returns are positively related to dividend yield as well as to beta. These results are consistent with after-tax extensions of the CAPM developed by Breenan (1973) and Litzenberger and Ramaswamy (1979) and suggest that the relationship between return, beta, and dividend yield should be estimated and employed to calculate the cost of equity capital.

As far as skewness is concerned, investors are more concerned with losing money than with total variability of return. If risk is defined as the probability of loss, it appears more logical to measure risk as the probability of achieving a return which is below the expected return. The traditional CAPM provides downward-biased estimates of cost of capital to the extent that these skewness effects are significant. As shown by Kraus and Litzenberger (1976), expected return depends on both on a stock's systematic risk (beta) and the systematic skewness. Empirical studies by Kraus and Litzenberger (1976), Friend, Westerfield, and Granito (1978), and Morin (1981) found that, in addition to beta, skewness of returns has a significant negative relationship with security returns. This

result is consistent with the skewness version of the CAPM developed by Rubinstein (1973) and Kraus and Litzenberger (1976).

This is particularly relevant for public utilities whose future profitability is constrained by the regulatory process on the upside and relatively unconstrained on the downside in the face of socio-political realities of public utility regulation. The process of regulation, by restricting the upward potential for returns and responding sluggishly on the downward side, may impart some asymmetry to the distribution of returns, and is more likely to result in utilities earning less, rather than more, than their cost of capital. The traditional CAPM provides downward-biased estimates of cost of capital to the extent that these skewness effects are significant.

As far as hedging potential is concerned, investors are exposed to another kind of risk, namely, the risk of unfavorable shifts in the investment opportunity set. Merton (1973) shows that investors will hold portfolios consisting of three funds: the risk-free asset, the market portfolio, and a portfolio whose returns are perfectly negatively correlated with the riskless asset so as to hedge against unforeseen changes in the future risk-free rate. The higher the degree of protection offered by an asset against unforeseen changes in interest rates, the lower the required return, and conversely. Merton argues that low beta assets, like utility stocks, offer little protection against changes in interest rates, and require higher returns than suggested by the standard CAPM.

Another explanation for the CAPM's inability to fully explain the process determining security returns involves the use of an inadequate or incomplete market index. Empirical studies to validate the CAPM invariably rely on some stock market index as a proxy for the true market portfolio. The exclusion of several asset categories from the definition of market index mis-specifies the CAPM and biases the results found using only stock market data. Kolbe and Read (1983) illustrate the biases in beta estimates which result from applying the CAPM to public utilities. Unfortunately, no comprehensive and easily accessible data exist for several classes of assets, such as mortgages and business investments, so that the exact relation between return and stock betas predicted by the CAPM does not exist. This suggests that the empirical relationship between returns and stock betas is best estimated empirically (ECAPM) rather than by relying on theoretical and elegant CAPM models expanded to include missing assets

effects. In any event, stock betas may be highly correlated with the true beta measured with the true market index.

Yet another explanation for the CAPM's inability to fully explain the observed risk-return tradeoff involves the possibility of constraints on investor borrowing that run counter to the assumptions of the CAPM. In response to this inadequacy, several versions of the CAPM have been developed by researchers. One of these versions is the so-called zero-beta, or two-factor, CAPM which provides for a risk-free return in a market where borrowing and lending rates are divergent. If borrowing rates and lending rates differ, or there is no risk-free borrowing or lending, or there is risk-free lending but no risk-free borrowing, then the CAPM has the following form:

$$K = R_Z + \beta(R_m - R_F)$$

The model, christened the zero-beta model, is analogous to the standard CAPM, but with the return on a minimum risk portfolio which is unrelated to market returns, R_Z , replacing the risk-free rate, R_F . The model has been empirically tested by Black, Jensen, and Scholes (1972), who found a flatter than predicted CAPM, consistent with the model and other researchers' findings.

The zero-beta CAPM cannot be literally employed in cost of capital projections, since the zero-beta portfolio is a statistical construct difficult to replicate.

Empirical Evidence

A summary of the empirical evidence on the magnitude of alpha is provided in the table below.

Empirical Evidence on the Alpha Factor		
Author	Range of alpha	Period relied
Black (1993)	-3.6% to 3.6%	1931-1991
Black, Jensen and Scholes (1972)	-9.61% to 12.24%	1931-1965
Fama and McBeth (1972)	4.08% to 9.36%	1935-1968
Fama and French (1992)	10.08% to 13.56%	1941-1990
Litzenberger and Ramaswamy (1979)	5.32% to 8.17%	
Litzenberger, Ramaswamy and Sosin (1980)	1.63% to 5.04%	1926-1978
Pettengill, Sundaram and Mathur (1995)	4.6%	
Morin (1994)	2.0%	1926-1984
Harris, Marston, Mishra, and O'Brien (2003)	2.0%	1983-1998

Given the observed magnitude of alpha, the empirical evidence indicates that the risk-return relationship is flatter than that predicted by the CAPM. Typical of the empirical evidence is the findings cited in Morin (1989) over the period 1926-1984 indicating that the observed expected return on a security is related to its risk by the following equation:

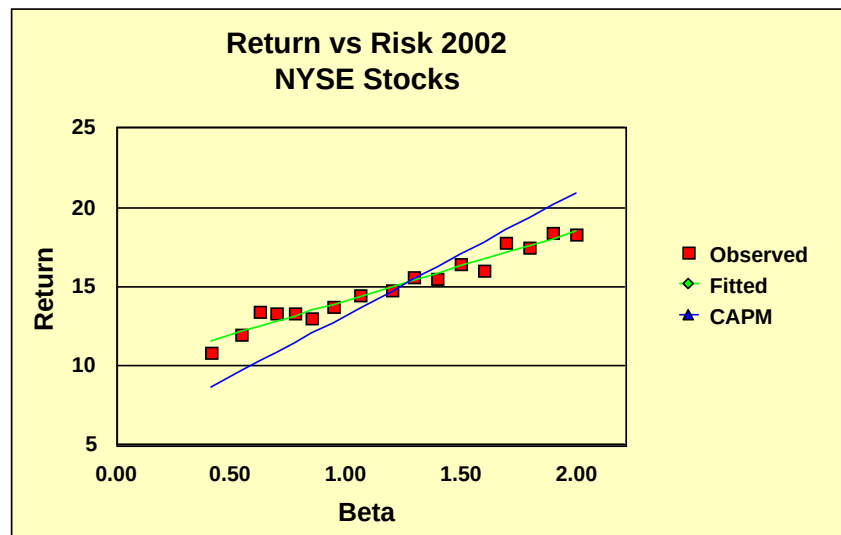
$$K = .0829 + .0520 \beta$$

Given that the risk-free rate over the estimation period was approximately 6 percent, this relationship implies that the intercept of the risk-return relationship is higher than the 6 percent risk-free rate, contrary to the CAPM's prediction. Given that the average return on an average risk stock exceeded the risk-free rate by about 8.0 percent in that period, that is, the market risk premium ($R_M - R_F$) = 8 percent, the intercept of the observed relationship between return and beta exceeds the risk-free rate by about 2 percent, suggesting an alpha factor of 2 percent.

Most of the empirical studies cited in the above table utilize raw betas rather than Value Line adjusted betas because the latter were not available over most of the time periods covered in these studies. A study of the relationship between return and adjusted beta is reported on Table 6-7 in Ibbotson Associates Valuation Yearbook 2001. If we

exclude the portfolio of very small cap stocks from the relationship due to significant size effects, the relationship between the arithmetic mean return and beta for the remaining portfolios is flatter than predicted and the intercept slightly higher than predicted by the CAPM, as shown on the graph below. It is noteworthy that the Ibbotson study relies on adjusted betas as stated on page 95 of the aforementioned study.

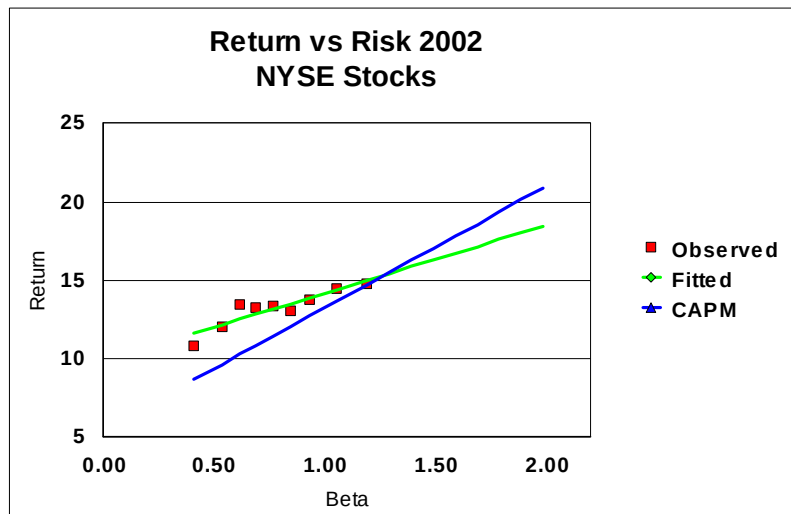
CAPM vs ECAPM



Another study by Morin in May 2002 provides empirical support for the ECAPM. All the stocks covered in the Value Line Investment Survey for Windows for which betas and returns data were available were retained for analysis. There were nearly 2000 such stocks. The expected return was measured as the total shareholder return ("TSR") reported by Value Line over the past ten years. The Value Line adjusted beta was also retrieved from the same data base. The nearly 2000 companies for which all data were available were ranked in ascending order of beta, from lowest to highest. In order to palliate measurement error, the nearly 2000 securities were grouped into ten portfolios of approximately 180 securities for each portfolio. The average returns and betas for each portfolio were as follows:

Portfolio #	Beta	Return
portfolio 1	0.41	10.87
portfolio 2	0.54	12.02
portfolio 3	0.62	13.50
portfolio 4	0.69	13.30
portfolio 5	0.77	13.39
portfolio 6	0.85	13.07
portfolio 7	0.94	13.75
portfolio 8	1.06	14.53
portfolio 9	1.19	14.78
portfolio 10	1.48	20.78

It is clear from the graph below that the observed relationship between DCF returns and Value Line adjusted betas is flatter than that predicted by the plain vanilla CAPM. The observed intercept is higher than the prevailing risk-free rate of 5.7 percent while the slope is less than equal to the market risk premium of 7.7 percent predicted by the plain vanilla CAPM for that period.



In an article published in Financial Management, Harris, Marston, Mishra, and O'Brien ("HMMO") estimate ex ante expected returns for S&P 500 companies over the period 1983-1998¹. HMMO measure the expected rate of return (cost of equity) of each dividend-paying stock in the S&P 500 for each month from January 1983 to August 1998 by using the constant growth DCF model. They then investigate the relation between the

risk premium (expected return over the 20-year U.S. Treasury Bond yield) estimates for each month to equity betas as of that same month (5-year raw betas).

The table below, drawn from HMMO Table 4, displays the average estimate prospective risk premium (Column 2) by industry and the corresponding beta estimate for that industry, both in raw form (Column 3) and adjusted form (Column 4). The latter were calculated with the traditional Value Line – Merrill Lynch – Bloomberg adjustment methodology by giving 1/3 weight of to a beta estimate of 1.00 and 2/3 weight to the raw beta estimate.

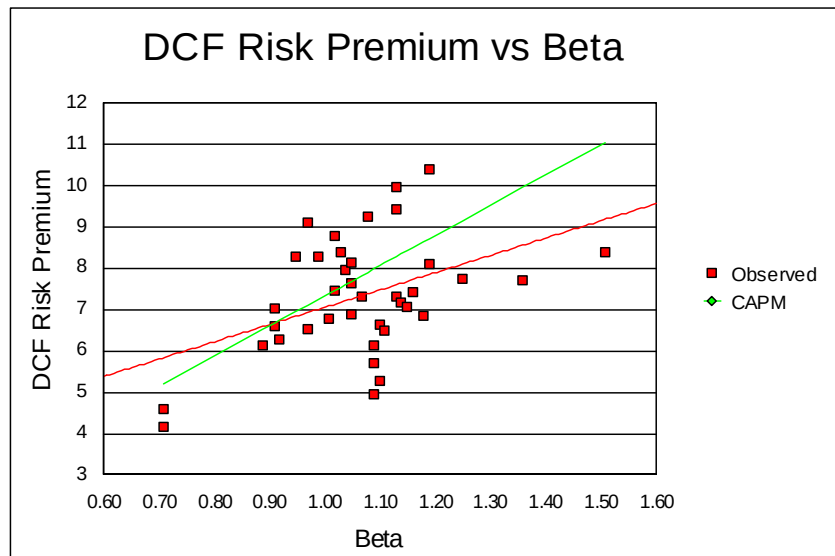
Table A-1 Risk Premium and Beta Estimates by Industry

	Industry	DCF Risk Premium	Raw Industry Beta	Adjusted Industry Beta
	(1)	(2)	(3)	(4)
1	Aero	6.63	1.15	1.10
2	Autos	5.29	1.15	1.10
3	Banks	7.16	1.21	1.14
4	Beer	6.60	0.87	0.91
5	BldMat	6.84	1.27	1.18
6	Books	7.64	1.07	1.05
7	Boxes	8.39	1.04	1.03
8	BusSv	8.15	1.07	1.05
9	Chems	6.49	1.16	1.11
10	Chips	8.11	1.28	1.19
11	Clths	7.74	1.37	1.25
12	Cnstr	7.70	1.54	1.36
13	Comps	9.42	1.19	1.13
14	Drugs	8.29	0.99	0.99
15	ElcEq	6.89	1.08	1.05
16	Energy	6.29	0.88	0.92
17	Fin	8.38	1.76	1.51
18	Food	7.02	0.86	0.91
19	Fun	9.98	1.19	1.13
20	Gold	4.59	0.57	0.71
21	Hlth	10.40	1.29	1.19
22	Hsld	6.77	1.02	1.01
23	Insur	7.46	1.03	1.02
24	LabEq	7.31	1.10	1.07
25	Mach	7.32	1.20	1.13
26	Meals	7.98	1.06	1.04
27	MedEq	8.80	1.03	1.02
28	Pap	6.14	1.13	1.09
29	PerSv	9.12	0.95	0.97
30	Retail	9.27	1.12	1.08
31	Rubber	7.06	1.22	1.15

¹ Harris, R. S., Marston, F. C., Mishra, D. R., and O'Brien, T. J., "Ex Ante Cost of Equity Estimates of S&P 500 Firms: The Choice Between Global and Domestic CAPM," Financial Management, Autumn 2003, pp. 51-66.

32	Ships	1.95	0.95	0.97
33	Stee	4.96	1.13	1.09
34	Tele	6.12	0.83	0.89
35	Toys	7.42	1.24	1.16
36	Trans	5.70	1.14	1.09
37	Txtls	6.52	0.95	0.97
38	Util	4.15	0.57	0.71
39	Whlsl	8.29	0.92	0.95
MEAN		7.19		

The observed statistical relationship between expected return and **adjusted beta** is shown in the graph below along with the CAPM prediction:



If the plain vanilla version of the CAPM is correct, then the intercept of the graph should be zero, recalling that the vertical axis represents returns in excess of the risk-free rate. Instead, the observed intercept is approximately 2 percent, that is approximately equal to 25 percent of the expected market risk premium of 7.2 percent shown at the bottom of Column 2 over the 1983-1998 period, as predicted by the ECAPM. The same is true for the slope of the graph. If the plain vanilla version of the CAPM is correct, then the slope of the relationship should equal the market risk premium of 7.2 percent. Instead, the observed slope of close to 5 percent is approximately equal to 75 percent of the expected market risk premium of 7.2 percent, as predicted by the ECAPM.

In short, the HMMO empirical findings are quite consistent with the predictions of the ECAPM.

Practical Implementation of the ECAPM

The empirical evidence reviewed above suggests that the expected return on a security is related to its risk by the following relationship:

$$K = R_F + \alpha + \beta (MRP - \alpha) \quad (5)$$

or, alternatively by the following equivalent relationship:

$$K = R_F + a MRP + (1-a) \beta MRP \quad (6)$$

The empirical findings support values of α from approximately 2 percent to 7 percent. If one is using the short-term U.S. Treasury Bills yield as a proxy for the risk-free rate, and given that utility stocks have lower than average betas, an alpha in the lower range of the empirical findings, 2 percent - 3 percent is reasonable, albeit conservative.

Using the long-term U.S. Treasury yield as a proxy for the risk-free rate, a lower alpha adjustment is indicated. This is because the use of the long-term U.S. Treasury yield as a proxy for the risk-free rate partially incorporates the desired effect of using the ECAPM². An alpha in the range of 1 percent - 2 percent is therefore reasonable.

To illustrate, consider a utility with a beta of 0.80. The risk-free rate is 5 percent, the MRP is 7 percent, and the alpha factor is 2 percent. The cost of capital is determined as follows:

$$\begin{aligned} K &= R_F + \alpha + \beta (MRP - \alpha) \\ K &= 5\% + 2\% + 0.80(7\% - 2\%) \\ &= 11\% \end{aligned}$$

² The Security Market Line (SML) using the long-term risk-free rate has a higher intercept and a flatter slope than the SML using the short-term risk-free rate

A practical alternative is to rely on the second variation of the ECAPM:

$$K = R_F + a \text{ MRP} + (1-a) \beta \text{ MRP}$$

With an alpha of 2 percent, a MRP in the 6 percent - 8 percent range, the ‘a’ coefficient is 0.25, and the ECAPM becomes³:

$$K = R_F + 0.25 \text{ MRP} + 0.75 \beta \text{ MRP}$$

Returning to the numerical example, the utility’s cost of capital is:

$$\begin{aligned} K &= 5\% + 0.25 \times 7\% + 0.75 \times 0.80 \times 7\% \\ &= 11\% \end{aligned}$$

For reasonable values of beta and the MRP, both renditions of the ECAPM produce results that are virtually identical⁴.

³ Recall that alpha equals ‘a’ times MRP, that is, $\alpha = a \text{ MRP}$, and therefore $a = \alpha / \text{MRP}$. If alpha is 2 percent, then $a = 0.25$

⁴ In the Morin (1994) study, the value of “a” was actually derived by systematically varying the constant "a" in equation 6 from 0 to 1 in steps of 0.05 and choosing that value of 'a' that minimized the mean square error between the observed relationship between return and beta:

$$K = 0.0829 + .0520 \beta$$

The value of a that best explained the observed relationship was 0.25.

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APPENDIX B

FLOTATION COST ALLOWANCE

To obtain the final cost of equity financing from the investors' expected rate of return, it is necessary to make allowance for underpricing, which is the sum of market pressure, costs of flotation, and underwriting fees associated with new issues. Allowance for market pressure should be made because large blocks of new stock may cause significant pressure on market prices even in stable markets. Allowance must also be made for company costs of flotation (including such items as printing, legal and accounting expenses) and for underwriting fees.

1. MAGNITUDE OF FLOTATION COSTS

According to empirical studies, underwriting costs and expenses average at least 4% of gross proceeds for utility stock offerings in the U.S. (See Logue & Jarrow: "Negotiations vs. Competitive Bidding in the Sale of Securities by Public Utilities", Financial Management, Fall 1978.) A study of 641 common stock issues by 95 electric utilities identified a flotation cost allowance of 5.0%. (See Borum & Malley: "Total Flotation Cost for Electric Company Equity Issues", Public Utilities Fortnightly, Feb. 20, 1986.)

Empirical studies suggest an allowance of 1% for market pressure in U.S. studies. Logue and Jarrow found that the absolute magnitude of the relative price decline due to market pressure was less than 1.5%. Bowyer and Yawitz examined 278 public utility stock issues and found an average market pressure of 0.72%. (See Bowyer & Yawitz, "The Effect of New Equity Issues on Utility Stock Prices", Public Utilities Fortnightly, May 22, 1980.)

Eckbo & Masulis ("Rights vs. Underwritten Stock Offerings: An Empirical Analysis", University of British Columbia, Working Paper No. 1208, Sept., 1987) found an average flotation cost of 4.175% for utility common stock offerings. Moreover, flotation costs increased progressively for smaller size issues. They also found that the relative price decline due to market pressure in the days

surrounding the announcement amounted to slightly more than 1.5%. In a classic and monumental study published in the prestigious Journal of Financial Economics by a prominent scholar, a market pressure effect of 3.14% for industrial stock issues and 0.75% for utility common stock issues was found (see Smith, C.W., "Investment Banking and the Capital Acquisition Process," Journal of Financial Economics 15, 1986). Other studies of market pressure are reported in Logue ("On the Pricing of Unseasoned Equity Offerings, Journal of Financial and Quantitative Analysis, Jan. 1973), Pettway ("The Effects of New Equity Sales Upon Utility Share Prices," Public Utilities Fortnightly, May 10 1984), and Reilly and Hatfield ("Investor Experience with New Stock Issues," Financial Analysts' Journal, Sept.- Oct. 1969). In the Pettway study, the market pressure effect for a sample of 368 public utility equity sales was in the range of 2% to 3%. Adding the direct and indirect effects of utility common stock issues, the indicated total flotation cost allowance is above 5.0%, corroborating the results of earlier studies.

As shown in the table below, a comprehensive empirical study by Lee, Lochhead, Ritter, and Zhao, "The Costs of Raising Capital," Journal of Financial Research, Vol. XIX, NO. 1, Spring 1996, shows average direct flotation costs for equity offerings of 3.5% - 5% for stock issues between \$60 and \$500 million. Allowing for market pressure costs raises the flotation cost allowance to well above 5%.

FLOTATION COSTS: RAISING EXTERNAL CAPITAL

(Percent of Total Capital Raised)

Amount Raised in \$ Millions	Average Flotation Cost: Common Stock	Average Flotation Cost: New Debt
\$ 2 - 9.99	13.28%	4.39%
10 - 19.99	8.72	2.76
20 - 39.99	6.93	2.42
40 - 59.99	5.87	1.32
60 - 79.99	5.18	2.34
80 - 99.99	4.73	2.16
100 - 199.99	4.22	2.31
200 - 499.99	3.47	2.19
500 and Up	3.15	1.64

Note: Flotation costs for IPOs are about 17 percent of the value of common stock issued if the amount raised is less than \$10 million and about 6 percent if more than \$500 million is raised. Flotation costs are somewhat lower for utilities than others.

Source: Lee, Inmoo, Scott Lochhead, Jay Ritter, and Quanshui Zhao, "The Costs of Raising Capital," *The Journal of Financial Research*, Spring 1996.

Therefore, based on empirical studies, total flotation costs including market pressure amount to approximately 5% of gross proceeds. I have therefore assumed a 5% gross total flotation cost allowance in my cost of capital analyses.

2. APPLICATION OF THE FLOTATION COST ADJUSTMENT

The section below shows: 1) why it is necessary to apply an allowance of 5% to the dividend yield component of equity cost by dividing that yield by 0.95 (100% - 5%) to obtain the fair return on equity capital, and 2) why the flotation adjustment is permanently required to avoid confiscation even if

no further stock issues are contemplated. Flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years.

Flotation costs are just as real as costs incurred to build utility plant. Fair regulatory treatment absolutely must permit the recovery of these costs. An analogy with bond issues is useful to understand the treatment of flotation costs in the case of common stocks.

In the case of a bond issue, flotation costs are not expensed but are rather amortized over the life of the bond, and the annual amortization charge is embedded in the cost of service. This is analogous to the process of depreciation, which allows the recovery of funds invested in utility plant. The recovery of bond flotation expense continues year after year, irrespective of whether the company issues new debt capital in the future, until recovery is complete. In the case of common stock that has no finite life, flotation costs are not amortized. Therefore, the recovery of flotation cost requires an upward adjustment to the allowed return on equity. Roger A. Morin, Regulatory Finance, Public Utilities Reports Inc., Arlington, Va., 1994, provides numerical illustrations that show that even if a utility does not contemplate any additional common stock issues, a flotation cost adjustment is still permanently required. Examples there also demonstrate that the allowance applies to retained earnings as well as to the original capital.

From the standard DCF model, the investor's required return on equity capital is expressed as:

$$K = D_1/P_o + g$$

If P_o is regarded as the proceeds per share actually received by the company from which dividends and earnings will be generated, that is, P_o equals B_o , the book value per share, then the company's required return is:

$$r = D_1/B_o + g$$

Denoting the percentage flotation costs 'f', proceeds per share B_o are related to market price P_o as follows:

$$P - fP = B_o$$

$$P(1 - f) = B_o$$

Substituting the latter equation into the above expression for return on equity, we obtain:

$$r = D_1/P(1-f) + g$$

that is, the utility's required return adjusted for underpricing. For flotation costs of 5%, dividing the expected dividend yield by 0.95 will produce the adjusted cost of equity capital. For a dividend yield of 6% for example, the magnitude of the adjustment is 32 basis points: $.06/.95 = .0632$.

In deriving DCF estimates of fair return on equity, it is therefore necessary to apply a conservative after-tax allowance of 5% to the dividend yield component of equity cost.

Even if no further stock issues are contemplated, the flotation adjustment is still permanently required to keep shareholders whole. Flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years, even if no future financing is contemplated. This is demonstrated by the numerical example contained in pages 7-9 of this Appendix. Moreover, even if the stock price, hence the DCF estimate of equity return, fully reflected the lack of permanent allowance, the company always nets less than the market price. Only the net proceeds from an equity issue are used to add to the rate base on which the investor earns. A permanent allowance for flotation costs must be authorized in order to insure that in each year the investor earns the required return on the total amount of capital actually supplied.

The example shown on pages 7-9 shows the flotation cost adjustment process using illustrative, yet realistic, market data. The assumptions used in the computation are shown on page 7. The stock is selling in the market for \$25, investors expect the firm to pay a dividend of \$2.25 that will grow at a rate of 5% thereafter. The traditional DCF cost of equity is thus $k = D/P + g = 2.25/25 + .05 = 14\%$. The firm sells one share stock, incurring a flotation cost of 5%. The traditional DCF cost of equity adjusted for flotation cost is thus $ROE = D/P(1-f) + g = .09/.95 + .05 = 14.47\%$.

The initial book value (rate base) is the net proceeds from the stock issue, which are \$23.75, that is, the market price less the 5% flotation costs. The example demonstrates that only if the company is allowed to earn 14.47% on rate base will investors earn their cost of equity of 14%. On page 8, Column

1 shows the initial common stock account, Column 2 the cumulative retained earnings balance, starting at zero, and steadily increasing from the retention of earnings. Total equity in Column 3 is the sum of common stock capital and retained earnings. The stock price in Column 4 is obtained from the seminal DCF formula: $D_1/(k - g)$. Earnings per share in Column 6 are simply the allowed return of 14.47% times the total common equity base. Dividends start at \$2.25 and grow at 5% thereafter, which they must do if investors are to earn a 14% return. The dividend payout ratio remains constant, as per the assumption of the DCF model. All quantities, stock price, book value, earnings, and dividends grow at a 5% rate, as shown at the bottom of the relevant columns. Only if the company is allowed to earn 14.47% on equity do investors earn 14%. For example, if the company is allowed only 14%, the stock price drops from \$26.25 to \$26.13 in the second year, inflicting a loss on shareholders. This is shown on page 9. The growth rate drops from 5% to 4.53%. Thus, investors only earn $9\% + 4.53\% = 13.53\%$ on their investment. It is noteworthy that the adjustment is always required each and every year, whether or not new stock issues are sold in the future, and that the allowed return on equity must be earned on total equity, including retained earnings, for investors to earn the cost of equity.

ASSUMPTIONS:

ISSUE PRICE = \$25.00
FLOTATION COST = 5.00%
DIVIDEND YIELD = 9.00%
GROWTH = 5.00%

EQUITY RETURN = **14.00%**
 $(D/P + g)$
ALLOWED RETURN ON EQUITY = **14.47%**
 $(D/P(1-f) + g)$

					MARKET/ BOOK			
Yr	COMMON STOCK (1)	RETAINED EARNINGS (2)	TOTAL EQUITY (3)	STOCK PRICE (4)	RATIO (5)	EPS (6)	DPS (7)	PAYOUT (8)
1	\$23.75	\$0.000	\$23.750	\$25.000	1.0526	\$3.438	\$2.250	65.45%
2	\$23.75	\$1.188	\$24.938	\$26.250	1.0526	\$3.609	\$2.363	65.45%
3	\$23.75	\$2.434	\$26.184	\$27.563	1.0526	\$3.790	\$2.481	65.45%
4	\$23.75	\$3.744	\$27.494	\$28.941	1.0526	\$3.979	\$2.605	65.45%
5	\$23.75	\$5.118	\$28.868	\$30.388	1.0526	\$4.178	\$2.735	65.45%
6	\$23.75	\$6.562	\$30.312	\$31.907	1.0526	\$4.387	\$2.872	65.45%
7	\$23.75	\$8.077	\$31.827	\$33.502	1.0526	\$4.607	\$3.015	65.45%
8	\$23.75	\$9.669	\$33.419	\$35.178	1.0526	\$4.837	\$3.166	65.45%
9	\$23.75	\$11.340	\$35.090	\$36.936	1.0526	\$5.079	\$3.324	65.45%
10	\$23.75	\$13.094	\$36.844	\$38.783	1.0526	\$5.333	\$3.490	65.45%
			5.00%	5.00%		5.00%	5.00%	

Yr	COMMON STOCK (1)	RETAINED EARNINGS (2)	TOTAL EQUITY (3)	STOCK PRICE (4)	MARKET/ BOOK RATIO		EPS (6)	DPS (7)	PAYOUT (8)
					(5)				
1	\$23.75	\$0.000	\$23.750	\$25.000	1.0526		\$3.325	\$2.250	67.67%
2	\$23.75	\$1.075	\$24.825	\$26.132	1.0526		\$3.476	\$2.352	67.67%
3	\$23.75	\$2.199	\$25.949	\$27.314	1.0526		\$3.633	\$2.458	67.67%
4	\$23.75	\$3.373	\$27.123	\$28.551	1.0526		\$3.797	\$2.570	67.67%
5	\$23.75	\$4.601	\$28.351	\$29.843	1.0526		\$3.969	\$2.686	67.67%
6	\$23.75	\$5.884	\$29.634	\$31.194	1.0526		\$4.149	\$2.807	67.67%
7	\$23.75	\$7.225	\$30.975	\$32.606	1.0526		\$4.337	\$2.935	67.67%
8	\$23.75	\$8.627	\$32.377	\$34.082	1.0526		\$4.533	\$3.067	67.67%
9	\$23.75	\$10.093	\$33.843	\$35.624	1.0526		\$4.738	\$3.206	67.67%
10	\$23.75	\$11.625	\$35.375	\$37.237	1.0526		\$4.952	\$3.351	67.67%
							4.53%	4.53%	

Pike County Light & Power Co.
Exhibit G-10 Depreciation

<u>Schedule</u>	<u>Description</u>	<u>Pages</u>
1	Proposed Depreciation Rate Changes	2
2	Summary of Average Service Lives	17

PIKE COUNTY LIGHT AND POWER COMPANY

**PROPOSED DEPRECIATION RATE CHANGES
FOR GAS PLANT
AT DECEMBER 31, 2007**

JULY 2008

PIKE COUNTY LIGHT AND POWER COMPANY
PROPOSED DEPRECIATION RATE CHANGES FOR GAS PLANT
AT DECEMBER 31, 2007

ACCOUNT	ACCOUNT TITLE	BOOK BASIS					PROPOSED BASIS						
		BOOK COST	ACCUM PROVISION FOR DEPREC	AVG. SERVICE LIFE	ANNUAL DEPREC EXPENSE	COMPUTED RESERVE FOR DEPREC	RESERVE VARIATION	LIFE TABLE	AVG. SERVICE LIFE	ANNUAL DEPREC EXPENSE	COMPUTED RESERVE FOR DEPREC	RESERVE VARIATION	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
<u>GAS PLANT</u>													
<u>DISTRIBUTION PLANT</u>													
374000	LAND - EASEMENTS	1,551	625	h 3.0	60	26	587	37	h 3.0	60	26	587	37
376000	MAINS	865,596	173,090	h 2.5	70	12,378	209,948	(36,858)	h 2.5	70	12,378	209,948	(36,858)
378000	MEASURING AND REGULATING EQUIPMENT	77,776	41,931	h 1.5	30	2,590	29,460	12,471	h 1.5	30	2,590	29,460	12,471
380000	SERVICES	496,228	97,526	h 2.5	60	8,287	103,056	(5,530)	h 2.5	65	7,642	96,712	815
381000	METERS	82,468	21,725	h 2.5	35	2,359	25,873	(4,148)	h 2.5	30	2,746	28,959	(7,234)
382000	METER INSTALLATIONS	114,834	14,800	h 2.5	50	2,297	15,991	(1,191)	h 2.5	40	2,871	19,058	(4,258)
382400	METER BARS	17,882	1,340	h 2.5	50	358	1,509	(169)	h 2.5	40	447	1,875	(535)
384000	HOUSE REGULATOR INSTALLATIONS	16,598	1,844	h 2.5	50	332	1,865	(21)	h 2.5	40	415	2,310	(466)
385000	INDUSTRIAL MEASURING AND REGULATING EQUIPMENT	17,146	1,357	h 4.0	45	381	1,303	54	h 4.5	35	490	1,677	(320)
	TOTAL DISTRIBUTION PLANT	1,690,079	354,238			29,008	389,592	(35,355)			29,605	390,585	(36,347)
	TOTAL GAS	1,690,079	354,238			29,008	389,592	(35,355)			29,605	390,585	(36,347)
	RESERVE VARIATION PERCENTAGE							-9.07%					-9.31%

PIKE COUNTY LIGHT AND POWER COMPANY

GAS UTILITY PLANT

**SUMMARY OF AVERAGE SERVICE LIVES, EQUIVALENT "h" CURVES AND OTHER
STATISTICAL DATA INDICATED BY PLANT MORTALITY STUDIES BASED ON
EXPERIENCE THROUGH DECEMBER 31, 2006**

JULY 2008

ORANGE AND ROCKLAND UTILITIES INC. MORTALITY STUDY BY LEAST SQUARE FITTING OF WEIGHTED RETIREMENT RATIOS
ACCOUNT 2376000 MAINS PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2006

SUMMARY OF ROLLING BANDS

YEAR	YEAR	FIRST DEGREE				SECOND DEGREE				THIRD DEGREE			
		AVERAGE SERVICE LIFE (YEARS)	FIT INDEX	TERMINAL A/L RATIO (PERCENT)	EQUIV. H CURVE	AVERAGE SERVICE LIFE (YEARS)	FIT INDEX	TERMINAL A/L RATIO (PERCENT)	EQUIV. H CURVE	AVERAGE SERVICE LIFE (YEARS)	FIT INDEX	TERMINAL A/L RATIO (PERCENT)	EQUIV. H CURVE
1952 TO 1961	1952 TO 1961	96.75	0.000303	367.42	1.43	0.00	0.000000	0.00	0.00	98.70	0.000292	209.21	1.95
1953 TO 1962	1953 TO 1962	98.36	0.000251	368.55	1.41	0.00	0.000000	0.00	0.00	94.72	0.000234	202.17	2.10
1954 TO 1963	1954 TO 1963	87.74	0.000382	364.16	1.46	0.00	0.000000	0.00	0.00	110.79	0.000368	208.95	1.56
1955 TO 1964	1955 TO 1964	80.89	0.000463	360.38	1.51	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1956 TO 1965	1956 TO 1965	79.63	0.000460	358.55	1.53	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1957 TO 1966	1957 TO 1966	84.65	0.000431	358.52	1.53	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1958 TO 1967	1958 TO 1967	78.19	0.000447	358.73	1.52	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1959 TO 1968	1959 TO 1968	76.80	0.000419	357.42	1.54	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1960 TO 1969	1960 TO 1969	75.35	0.000432	361.63	1.49	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1961 TO 1970	1961 TO 1970	71.00	0.000459	359.84	1.51	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1962 TO 1971	1962 TO 1971	65.62	0.000548	354.32	1.58	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1963 TO 1972	1963 TO 1972	64.46	0.000576	351.36	1.62	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1964 TO 1973	1964 TO 1973	54.09	0.000765	342.96	1.71	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1965 TO 1974	1965 TO 1974	56.35	0.000679	343.39	1.73	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1966 TO 1975	1966 TO 1975	57.58	0.000670	344.74	1.70	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1967 TO 1976	1967 TO 1976	58.51	0.000702	342.67	1.73	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1968 TO 1977	1968 TO 1977	60.49	0.000668	339.72	1.76	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1969 TO 1978	1969 TO 1978	61.94	0.000637	338.25	1.79	60.70	0.000641	307.26	1.94	0.00	0.000000	0.00	0.00
1970 TO 1979	1970 TO 1979	64.00	0.000609	335.13	1.83	62.10	0.000613	295.50	2.04	0.00	0.000000	0.00	0.00
1971 TO 1980	1971 TO 1980	68.05	0.000606	334.29	1.84	64.53	0.000610	279.69	2.18	0.00	0.000000	0.00	0.00
1972 TO 1981	1972 TO 1981	72.93	0.000518	336.61	1.82	67.37	0.000519	267.91	2.27	0.00	0.000000	0.00	0.00
1973 TO 1982	1973 TO 1982	73.50	0.000509	334.00	1.85	66.22	0.000504	254.45	2.44	0.00	0.000000	0.00	0.00
1974 TO 1983	1974 TO 1983	88.28	0.000335	334.73	1.84	73.80	0.000322	240.51	2.67	0.00	0.000000	0.00	0.00
1975 TO 1984	1975 TO 1984	93.21	0.000269	335.26	1.87	76.59	0.000254	239.59	2.68	0.00	0.000000	0.00	0.00
1976 TO 1985	1976 TO 1985	98.13	0.000233	332.72	1.84	80.16	0.000219	238.90	2.73	0.00	0.000000	0.00	0.00
1977 TO 1986	1977 TO 1986	106.41	0.000219	334.07	1.85	84.94	0.000209	238.40	2.73	0.00	0.000000	0.00	0.00
1978 TO 1987	1978 TO 1987	115.84	0.000159	335.37	1.84	90.92	0.000150	240.32	2.70	0.00	0.000000	0.00	0.00
1979 TO 1988	1979 TO 1988	121.29	0.000165	328.54	1.80	97.36	0.000162	248.06	2.56	0.00	0.000000	0.00	0.00
1980 TO 1989	1980 TO 1989	101.71	0.000278	331.82	1.88	83.09	0.000270	241.30	2.70	0.00	0.000000	0.00	0.00
1981 TO 1990	1981 TO 1990	87.13	0.000346	327.65	1.94	75.26	0.000339	245.16	2.64	0.00	0.000000	0.00	0.00
1982 TO 1991	1982 TO 1991	85.37	0.000370	326.23	1.96	73.65	0.000362	242.37	2.69	0.00	0.000000	0.00	0.00
1983 TO 1992	1983 TO 1992	86.67	0.000340	327.09	1.94	74.82	0.000334	245.27	2.66	0.00	0.000000	0.00	0.00
1984 TO 1993	1984 TO 1993	84.94	0.000330	327.88	1.94	74.00	0.000323	246.62	2.62	0.00	0.000000	0.00	0.00
1985 TO 1994	1985 TO 1994	84.78	0.000314	328.51	1.92	74.04	0.000306	247.85	2.60	0.00	0.000000	0.00	0.00
1986 TO 1995	1986 TO 1995	83.11	0.000326	327.87	1.94	72.05	0.000313	242.20	2.68	0.00	0.000000	0.00	0.00
1987 TO 1996	1987 TO 1996	83.14	0.000311	328.06	1.92	72.05	0.000296	242.18	2.69	0.00	0.000000	0.00	0.00
1988 TO 1997	1988 TO 1997	83.14	0.000290	328.96	1.91	71.90	0.000272	242.71	2.68	0.00	0.000000	0.00	0.00
1989 TO 1998	1989 TO 1998	80.66	0.000328	330.39	1.90	70.00	0.000308	240.73	2.70	0.00	0.000000	0.00	0.00
1990 TO 1999	1990 TO 1999	82.48	0.000337	332.82	1.86	70.61	0.000315	238.55	2.71	0.00	0.000000	0.00	0.00
1991 TO 2000	1991 TO 2000	82.91	0.000405	333.49	1.85	70.56	0.000387	237.37	2.74	0.00	0.000000	0.00	0.00
1992 TO 2001	1992 TO 2001	83.24	0.000390	338.16	1.80	70.47	0.000369	237.68	2.67	0.00	0.000000	0.00	0.00
1993 TO 2002	1993 TO 2002	83.68	0.000376	338.80	1.79	70.85	0.000354	237.81	2.66	0.00	0.000000	0.00	0.00
1994 TO 2003	1994 TO 2003	80.93	0.000411	335.47	1.82	68.89	0.000382	233.00	2.76	0.00	0.000000	0.00	0.00
1995 TO 2004	1995 TO 2004	78.90	0.000426	335.25	1.83	67.52	0.000390	231.77	2.83	0.00	0.000000	0.00	0.00
1996 TO 2005	1996 TO 2005	79.35	0.000400	334.59	1.83	67.80	0.000359	229.34	2.83	0.00	0.000000	0.00	0.00
1997 TO 2006	1997 TO 2006	76.96	0.000417	334.58	1.83	66.46	0.000372	229.46	2.81	0.00	0.000000	0.00	0.00

ORANGE AND ROCKLAND UTILITIES INC. MORTALITY STUDY BY LEAST SQUARE FITTING OF WEIGHTED RETIREMENT RATIOS
PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2006

ACCOUNT 2376000 MAINS

SUMMARY OF SHRINKING BANDS

YEAR	YEAR	AVERAGE SERVICE LIFE (YEARS)	FIRST DEGREE			SECOND DEGREE			THIRD DEGREE			EQUIV. H CURVE	
			FIT INDEX	TERMINAL A/L RATIO (PERCENT)	EQUIV. H CURVE	AVERAGE SERVICE LIFE (YEARS)	FIT INDEX	TERMINAL A/L RATIO (PERCENT)	EQUIV. H CURVE	AVERAGE SERVICE LIFE (YEARS)	FIT INDEX		TERMINAL A/L RATIO (PERCENT)
2006	TO 2006	70.79	0.000987	335.52	1.82	62.96	0.000961	231.09	2.75	62.74	0.000965	219.15	2.78
2005	TO 2006	77.15	0.000686	332.45	1.86	66.49	0.000649	223.33	2.96	66.22	0.000651	212.17	3.01
2004	TO 2006	75.68	0.000706	332.30	1.87	65.71	0.000667	222.95	2.96	65.50	0.000670	214.49	3.00
2003	TO 2006	73.57	0.000595	328.27	1.91	64.70	0.000542	221.79	3.02	64.70	0.000545	221.80	3.02
2002	TO 2006	75.58	0.000540	330.12	1.89	65.94	0.000495	225.19	2.96	0.00	0.000000	0.00	0.00
2001	TO 2006	76.55	0.000508	333.77	1.84	66.26	0.000465	227.13	2.87	0.00	0.000000	0.00	0.00
2000	TO 2006	75.49	0.000480	333.17	1.85	65.84	0.000439	228.57	2.84	0.00	0.000000	0.00	0.00
1999	TO 2006	75.90	0.000464	335.30	1.83	65.80	0.000419	228.73	2.83	0.00	0.000000	0.00	0.00
1998	TO 2006	75.77	0.000438	334.57	1.83	65.77	0.000391	230.35	2.81	0.00	0.000000	0.00	0.00
1997	TO 2006	76.96	0.000417	334.58	1.83	66.46	0.000372	229.46	2.81	0.00	0.000000	0.00	0.00
1996	TO 2006	78.13	0.000407	334.68	1.83	67.10	0.000363	230.25	2.82	0.00	0.000000	0.00	0.00
1995	TO 2006	78.49	0.000401	334.45	1.84	67.25	0.000356	229.75	2.84	0.00	0.000000	0.00	0.00
1994	TO 2006	79.15	0.000385	334.16	1.84	67.69	0.000342	229.71	2.83	0.00	0.000000	0.00	0.00
1993	TO 2006	79.18	0.000374	334.06	1.84	67.80	0.000332	230.81	2.82	0.00	0.000000	0.00	0.00
1992	TO 2006	79.44	0.000364	334.23	1.84	68.00	0.000323	231.61	2.81	0.00	0.000000	0.00	0.00
1991	TO 2006	79.52	0.000357	333.87	1.86	68.07	0.000315	231.39	2.81	0.00	0.000000	0.00	0.00
1990	TO 2006	78.39	0.000344	333.57	1.86	67.60	0.000302	232.99	2.79	0.00	0.000000	0.00	0.00
1989	TO 2006	77.81	0.000342	332.23	1.86	67.22	0.000298	232.80	2.79	0.00	0.000000	0.00	0.00
1988	TO 2006	78.34	0.000335	332.53	1.86	67.57	0.000293	233.11	2.79	0.00	0.000000	0.00	0.00
1987	TO 2006	79.05	0.000332	333.35	1.86	67.97	0.000291	233.21	2.79	0.00	0.000000	0.00	0.00
1986	TO 2006	79.69	0.000328	333.15	1.86	68.33	0.000288	233.42	2.80	0.00	0.000000	0.00	0.00
1985	TO 2006	80.19	0.000323	332.35	1.86	68.64	0.000284	232.36	2.79	0.00	0.000000	0.00	0.00
1984	TO 2006	80.62	0.000317	333.04	1.86	68.90	0.000279	232.96	2.80	0.00	0.000000	0.00	0.00
1983	TO 2006	80.83	0.000314	332.16	1.87	69.01	0.000275	232.58	2.80	0.00	0.000000	0.00	0.00
1982	TO 2006	80.71	0.000311	332.67	1.87	68.93	0.000272	232.84	2.80	0.00	0.000000	0.00	0.00
1981	TO 2006	80.88	0.000307	331.98	1.87	69.06	0.000269	233.85	2.80	0.00	0.000000	0.00	0.00
1980	TO 2006	81.11	0.000303	332.28	1.87	69.21	0.000265	233.36	2.80	0.00	0.000000	0.00	0.00
1979	TO 2006	81.19	0.000299	331.93	1.87	69.29	0.000261	233.09	2.79	0.00	0.000000	0.00	0.00
1978	TO 2006	81.17	0.000296	332.02	1.87	69.26	0.000258	233.18	2.80	0.00	0.000000	0.00	0.00
1977	TO 2006	81.15	0.000293	332.08	1.87	69.24	0.000254	233.23	2.80	0.00	0.000000	0.00	0.00
1976	TO 2006	81.14	0.000291	332.12	1.87	69.25	0.000252	233.21	2.80	0.00	0.000000	0.00	0.00
1975	TO 2006	81.16	0.000289	332.06	1.87	69.25	0.000250	233.22	2.78	0.00	0.000000	0.00	0.00
1974	TO 2006	81.18	0.000286	331.97	1.87	69.27	0.000247	233.14	2.78	0.00	0.000000	0.00	0.00
1973	TO 2006	80.20	0.000286	333.55	1.86	68.82	0.000249	234.67	2.75	0.00	0.000000	0.00	0.00
1972	TO 2006	80.11	0.000283	332.68	1.86	68.86	0.000245	235.99	2.74	0.00	0.000000	0.00	0.00
1971	TO 2006	79.87	0.000280	333.65	1.86	68.83	0.000243	236.09	2.72	0.00	0.000000	0.00	0.00
1970	TO 2006	79.78	0.000278	334.04	1.85	68.83	0.000242	237.53	2.71	0.00	0.000000	0.00	0.00
1969	TO 2006	79.81	0.000276	333.91	1.85	68.83	0.000241	237.54	2.69	0.00	0.000000	0.00	0.00
1968	TO 2006	79.81	0.000275	333.91	1.84	68.87	0.000241	237.42	2.69	0.00	0.000000	0.00	0.00
1967	TO 2006	79.77	0.000274	334.07	1.84	68.86	0.000240	238.90	2.68	0.00	0.000000	0.00	0.00
1966	TO 2006	79.84	0.000273	335.03	1.84	68.90	0.000239	238.75	2.68	0.00	0.000000	0.00	0.00
1965	TO 2006	79.83	0.000272	335.32	1.83	68.92	0.000238	238.69	2.67	0.00	0.000000	0.00	0.00
1964	TO 2006	79.77	0.000271	335.45	1.83	68.92	0.000238	238.67	2.66	0.00	0.000000	0.00	0.00
1963	TO 2006	79.74	0.000270	335.45	1.83	68.92	0.000237	240.03	2.66	0.00	0.000000	0.00	0.00
1962	TO 2006	79.79	0.000269	335.26	1.83	68.95	0.000236	239.92	2.66	0.00	0.000000	0.00	0.00
1961	TO 2006	79.83	0.000269	335.09	1.83	68.98	0.000236	239.92	2.66	0.00	0.000000	0.00	0.00
1960	TO 2006	79.88	0.000268	334.88	1.83	69.01	0.000235	239.78	2.65	0.00	0.000000	0.00	0.00
1959	TO 2006	79.92	0.000267	335.97	1.83	69.02	0.000235	239.78	2.65	0.00	0.000000	0.00	0.00
1958	TO 2006	79.95	0.000267	335.83	1.82	69.05	0.000234	239.69	2.65	0.00	0.000000	0.00	0.00
1957	TO 2006	79.99	0.000266	335.65	1.82	69.07	0.000234	239.60	2.65	0.00	0.000000	0.00	0.00
1956	TO 2006	79.98	0.000266	335.71	1.82	69.08	0.000233	239.58	2.65	0.00	0.000000	0.00	0.00
1955	TO 2006	79.98	0.000265	335.72	1.82	69.08	0.000233	239.58	2.65	0.00	0.000000	0.00	0.00
1954	TO 2006	79.99	0.000265	335.66	1.82	69.08	0.000233	239.58	2.65	0.00	0.000000	0.00	0.00

ORANGE AND ROCKLAND UTILITIES INC. MORTALITY STUDY BY LEAST SQUARE FITTING OF WEIGHTED RETIREMENT RATIOS
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SUMMARY OF SHRINKING BANDS

YEAR	YEAR	FIRST DEGREE				SECOND DEGREE				THIRD DEGREE			
		AVERAGE SERVICE LIFE (YEARS)	FIT INDEX	TERMINAL A/L RATIO (PERCENT)	EQUIV. H CURVE	AVERAGE SERVICE LIFE (YEARS)	FIT INDEX	TERMINAL A/L RATIO (PERCENT)	EQUIV. H CURVE	AVERAGE SERVICE LIFE (YEARS)	FIT INDEX	TERMINAL A/L RATIO (PERCENT)	EQUIV. H CURVE
1953 TO 2006	2006	80.02	0.000265	335.54	1.82	69.10	0.000232	239.52	2.65	0.00	0.000000	0.00	0.00
1952 TO 2006	2006	80.02	0.000265	335.53	1.82	69.10	0.000232	239.51	2.65	0.00	0.000000	0.00	0.00

ORANGE AND ROCKLAND UTILITIES INC. MORTALITY STUDY BY LEAST SQUARE FITTING OF WEIGHTED RETIREMENT RATIOS
ACCOUNT 2378000 MEAS. AND REG. EQUIPMENT PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2006
SUMMARY OF ROLLING BANDS

YEAR	YEAR	FIRST DEGREE				SECOND DEGREE				THIRD DEGREE			
		AVERAGE SERVICE LIFE (YEARS)	FIT INDEX	TERMINAL A/L RATIO (PERCENT)	EQUIV. H CURVE	AVERAGE SERVICE LIFE (YEARS)	FIT INDEX	TERMINAL A/L RATIO (PERCENT)	EQUIV. H CURVE	AVERAGE SERVICE LIFE (YEARS)	FIT INDEX	TERMINAL A/L RATIO (PERCENT)	EQUIV. H CURVE
1952 TO 1961	1952 TO 1961	42.88	0.002065	483.86	0.32	0.00	0.000000	0.00	0.00	45.38	0.002061	263.30	0.54
1953 TO 1962	1953 TO 1962	66.01	0.001471	603.67	-1.54	0.00	0.000000	0.00	0.00	52.31	0.001459	203.61	1.39
1954 TO 1963	1954 TO 1963	54.77	0.001396	539.50	-0.15	0.00	0.000000	0.00	0.00	52.21	0.001370	203.97	1.34
1955 TO 1964	1955 TO 1964	61.20	0.001284	553.06	-0.26	0.00	0.000000	0.00	0.00	55.86	0.001271	203.19	1.42
1956 TO 1965	1956 TO 1965	55.63	0.001234	515.00	0.05	0.00	0.000000	0.00	0.00	52.57	0.001187	187.38	1.73
1957 TO 1966	1957 TO 1966	65.74	0.001138	552.93	-0.27	59.79	0.001147	398.89	0.45	54.02	0.001123	193.46	1.79
1958 TO 1967	1958 TO 1967	38.88	0.002558	420.55	0.86	0.00	0.000000	0.00	0.00	43.79	0.002569	282.03	0.69
1959 TO 1968	1959 TO 1968	41.17	0.002040	416.52	0.90	0.00	0.000000	0.00	0.00	46.42	0.002045	276.82	0.79
1960 TO 1969	1960 TO 1969	45.27	0.001610	403.17	1.04	0.00	0.000000	0.00	0.00	51.04	0.001614	275.26	0.93
1961 TO 1970	1961 TO 1970	43.31	0.001400	419.04	0.89	0.00	0.000000	0.00	0.00	50.02	0.001380	262.92	0.85
1962 TO 1971	1962 TO 1971	33.66	0.003958	375.85	1.31	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1963 TO 1972	1963 TO 1972	33.42	0.002975	387.45	1.17	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1964 TO 1973	1964 TO 1973	34.45	0.002321	381.68	1.26	0.00	0.000000	0.00	0.00	35.41	0.002117	306.40	1.32
1965 TO 1974	1965 TO 1974	34.05	0.002098	362.71	1.45	0.00	0.000000	0.00	0.00	37.18	0.002214	361.75	1.39
1966 TO 1975	1966 TO 1975	34.66	0.002313	350.50	1.60	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1967 TO 1976	1967 TO 1976	36.01	0.002189	348.52	1.63	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1968 TO 1977	1968 TO 1977	40.03	0.001964	358.49	1.51	39.16	0.001975	320.50	1.67	0.00	0.000000	0.00	0.00
1969 TO 1978	1969 TO 1978	37.87	0.001886	357.83	1.53	37.65	0.001839	343.98	1.58	37.73	0.001912	316.75	1.60
1970 TO 1979	1970 TO 1979	37.40	0.001826	356.91	1.52	37.40	0.001839	357.00	1.52	37.49	0.001851	313.40	1.55
1971 TO 1980	1971 TO 1980	39.29	0.001657	349.98	1.62	38.56	0.001666	315.12	1.76	0.00	0.000000	0.00	0.00
1972 TO 1981	1972 TO 1981	42.04	0.001510	357.96	1.52	39.43	0.001507	285.59	1.88	0.00	0.000000	0.00	0.00
1973 TO 1982	1973 TO 1982	42.12	0.001577	357.31	1.52	40.37	0.001482	281.16	1.87	0.00	0.000000	0.00	0.00
1974 TO 1983	1974 TO 1983	43.31	0.001487	363.67	1.46	35.02	0.002267	295.55	1.76	0.00	0.000000	0.00	0.00
1975 TO 1984	1975 TO 1984	36.32	0.002263	359.27	1.50	37.30	0.002070	293.59	1.75	0.00	0.000000	0.00	0.00
1976 TO 1985	1976 TO 1985	39.10	0.002067	364.42	1.45	36.22	0.001922	296.81	1.75	0.00	0.000000	0.00	0.00
1977 TO 1986	1977 TO 1986	37.73	0.001922	361.79	1.48	0.00	0.001236	277.74	1.99	0.00	0.000000	0.00	0.00
1978 TO 1987	1978 TO 1987	34.75	0.002148	341.03	1.73	33.66	0.002014	279.74	2.05	0.00	0.000000	0.00	0.00
1979 TO 1988	1979 TO 1988	33.47	0.002026	336.09	1.79	32.71	0.002014	302.39	1.87	0.00	0.000000	0.00	0.00
1980 TO 1989	1980 TO 1989	28.10	0.002414	339.84	1.76	27.94	0.002414	323.13	1.72	0.00	0.000000	0.00	0.00
1981 TO 1990	1981 TO 1990	27.49	0.002413	347.46	1.66	27.39	0.002423	304.61	1.76	0.00	0.000000	0.00	0.00
1982 TO 1991	1982 TO 1991	27.22	0.002345	347.15	1.64	27.08	0.002339	321.77	1.85	0.00	0.000000	0.00	0.00
1983 TO 1992	1983 TO 1992	23.40	0.002526	335.41	1.81	23.46	0.002538	283.65	2.05	0.00	0.000000	0.00	0.00
1984 TO 1993	1984 TO 1993	23.15	0.002631	326.11	1.91	23.44	0.002550	297.29	1.99	0.00	0.000000	0.00	0.00
1985 TO 1994	1985 TO 1994	23.54	0.002554	329.22	1.88	23.71	0.002550	296.59	2.01	0.00	0.000000	0.00	0.00
1986 TO 1995	1986 TO 1995	23.96	0.002480	327.66	1.90	24.11	0.002479	303.48	1.94	0.00	0.000000	0.00	0.00
1987 TO 1996	1987 TO 1996	24.49	0.002455	332.85	1.84	24.55	0.002463	323.91	1.81	0.00	0.000000	0.00	0.00
1988 TO 1997	1988 TO 1997	25.49	0.002119	335.49	1.77	25.47	0.002132	315.01	1.86	0.00	0.000000	0.00	0.00
1989 TO 1998	1989 TO 1998	26.56	0.002077	336.95	1.79	26.51	0.002088	318.17	1.62	0.00	0.000000	0.00	0.00
1990 TO 1999	1990 TO 1999	29.52	0.002210	360.73	1.48	29.07	0.002218	316.32	1.64	0.00	0.000000	0.00	0.00
1991 TO 2000	1991 TO 2000	31.09	0.002322	358.64	1.49	30.51	0.002331	319.33	1.66	0.00	0.000000	0.00	0.00
1992 TO 2001	1992 TO 2001	30.97	0.002246	353.56	1.56	30.53	0.002257	0.00	0.00	34.95	0.001884	261.80	1.30
1993 TO 2002	1993 TO 2002	35.90	0.001875	422.00	0.85	0.00	0.000000	0.00	0.00	38.28	0.001720	265.12	1.12
1994 TO 2003	1994 TO 2003	39.35	0.001711	451.05	0.58	0.00	0.000000	0.00	0.00	37.55	0.001767	328.93	0.96
1995 TO 2004	1995 TO 2004	37.66	0.001747	426.18	0.80	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1996 TO 2005	1996 TO 2005	31.28	0.002048	417.21	0.89	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1997 TO 2006	1997 TO 2006	29.87	0.002301	403.39	1.02	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00

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SUMMARY OF SHRINKING BANDS

YEAR	YEAR	AVERAGE SERVICE LIFE (YEARS)	FIRST DEGREE			SECOND DEGREE			THIRD DEGREE			EQUIV. H CURVE	
			FIT INDEX	TERMINAL A/L RATIO (PERCENT)	EQUIV. H CURVE	AVERAGE SERVICE LIFE (YEARS)	FIT INDEX	TERMINAL A/L RATIO (PERCENT)	EQUIV. H CURVE	AVERAGE SERVICE LIFE (YEARS)	FIT INDEX		TERMINAL A/L RATIO (PERCENT)
2006	TO 2006	27.27	0.005471	357.56	1.53	0.00	0.000000	0.00	0.00	27.84	0.005384	285.61	1.15
2005	TO 2006	22.29	0.005552	388.12	1.15	0.00	0.000000	0.00	0.00	31.07	0.005513	905.91	-2.60
2004	TO 2006	24.86	0.004489	360.04	1.46	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
2003	TO 2006	27.37	0.003820	352.56	1.56	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
2002	TO 2006	25.82	0.003627	416.41	1.08	0.00	0.000000	0.00	0.00	57.00	0.003617	699.14	-2.60
2001	TO 2006	26.46	0.003330	398.66	1.05	0.00	0.000000	0.00	0.00	29.30	0.003333	588.81	-0.07
2000	TO 2006	27.85	0.003002	389.58	1.14	0.00	0.000000	0.00	0.00	51.97	0.002997	766.81	-2.60
1999	TO 2006	28.33	0.002789	425.41	0.81	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1998	TO 2006	29.17	0.002525	406.20	1.00	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1997	TO 2006	29.87	0.002301	403.39	1.02	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1996	TO 2006	30.44	0.002059	405.76	1.01	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1995	TO 2006	31.11	0.001938	400.15	1.07	0.00	0.000000	0.00	0.00	57.18	0.001943	696.92	-2.60
1994	TO 2006	30.94	0.001788	395.97	1.11	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1993	TO 2006	30.70	0.001702	382.77	1.22	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1992	TO 2006	28.69	0.001718	371.21	1.37	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1991	TO 2006	28.67	0.001676	367.97	1.38	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1990	TO 2006	28.68	0.001611	371.28	1.37	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1989	TO 2006	27.85	0.001604	368.01	1.39	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1988	TO 2006	27.85	0.001529	364.42	1.41	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1987	TO 2006	27.85	0.001555	364.45	1.44	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1986	TO 2006	27.98	0.001538	362.76	1.45	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1985	TO 2006	28.26	0.001504	362.71	1.45	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1984	TO 2006	28.09	0.001500	361.30	1.46	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1983	TO 2006	28.26	0.001479	362.73	1.46	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1982	TO 2006	28.36	0.001472	361.49	1.45	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1981	TO 2006	28.42	0.001473	364.24	1.45	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1980	TO 2006	28.55	0.001463	362.48	1.45	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1979	TO 2006	28.63	0.001445	361.50	1.45	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1978	TO 2006	28.67	0.001429	364.53	1.45	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1977	TO 2006	28.75	0.001424	363.44	1.45	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1976	TO 2006	28.86	0.001407	362.13	1.45	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1975	TO 2006	28.91	0.001385	361.46	1.46	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1974	TO 2006	28.96	0.001379	360.89	1.46	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1973	TO 2006	29.01	0.001374	360.23	1.47	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1972	TO 2006	29.03	0.001367	363.42	1.46	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1971	TO 2006	28.96	0.001367	360.83	1.46	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1970	TO 2006	28.97	0.001364	360.69	1.46	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1969	TO 2006	29.02	0.001360	363.51	1.46	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1968	TO 2006	29.07	0.001356	362.95	1.46	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1967	TO 2006	29.03	0.001341	363.37	1.46	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1966	TO 2006	29.07	0.001339	362.92	1.46	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1965	TO 2006	29.08	0.001335	362.84	1.46	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1964	TO 2006	29.10	0.001333	362.53	1.46	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1963	TO 2006	29.11	0.001330	362.37	1.46	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1962	TO 2006	29.14	0.001328	362.10	1.46	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1961	TO 2006	29.14	0.001327	362.00	1.46	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1960	TO 2006	29.16	0.001326	361.82	1.46	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1959	TO 2006	29.15	0.001325	361.91	1.45	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1958	TO 2006	29.16	0.001324	361.80	1.45	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1957	TO 2006	29.17	0.001322	361.67	1.45	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1956	TO 2006	29.17	0.001322	361.63	1.45	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1955	TO 2006	29.17	0.001321	361.66	1.45	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1954	TO 2006	29.17	0.001317	361.65	1.45	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00

ORANGE AND ROCKLAND UTILITIES INC. MORTALITY STUDY BY LEAST SQUARE FITTING OF WEIGHTED RETIREMENT RATIOS
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SUMMARY OF SHRINKING BANDS

YEAR	YEAR	FIRST DEGREE			SECOND DEGREE			THIRD DEGREE		
		AVERAGE SERVICE LIFE (YEARS)	FIT INDEX	TERMINAL A/L RATIO (PERCENT)	EQUIV. H CURVE	AVERAGE SERVICE LIFE (YEARS)	FIT INDEX	TERMINAL A/L RATIO (PERCENT)	EQUIV. H CURVE	TERMINAL A/L RATIO (PERCENT)
1953 TO 2006		29.18	0.001317	365.01	1.45	0.00	0.000000	0.00	0.00	0.00
1952 TO 2006		29.17	0.001317	361.65	1.45	0.00	0.000000	0.00	0.00	0.00

ORANGE AND ROCKLAND UTILITIES INC. MORTALITY STUDY BY LEAST SQUARE FITTING OF WEIGHTED RETIREMENT RATIOS
ACCOUNT 2380000 SERVICES PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2006
SUMMARY OF ROLLING BANDS

YEAR	YEAR	FIRST DEGREE			SECOND DEGREE			THIRD DEGREE			EQUIV. H CURVE		
		AVERAGE SERVICE LIFE (YEARS)	FIT INDEX	TERMINAL A/L RATIO (PERCENT)	EQUIV. H CURVE	AVERAGE SERVICE LIFE (YEARS)	FIT INDEX	TERMINAL A/L RATIO (PERCENT)	EQUIV. H CURVE	AVERAGE SERVICE LIFE (YEARS)		FIT INDEX	TERMINAL A/L RATIO (PERCENT)
1952 TO 1961	1952 TO 1961	55.22	0.000432	352.23	1.59	48.75	0.000341	238.96	2.50	47.02	0.000297	196.74	2.78
1953 TO 1962	1953 TO 1962	53.76	0.000439	354.35	1.58	48.05	0.000362	242.46	2.44	46.73	0.000340	204.35	2.67
1954 TO 1963	1954 TO 1963	52.26	0.000393	353.05	1.59	47.34	0.000320	248.18	2.35	46.13	0.000291	207.03	2.60
1955 TO 1964	1955 TO 1964	51.78	0.000335	350.55	1.63	47.45	0.000273	253.97	2.30	46.42	0.000256	214.36	2.53
1956 TO 1965	1956 TO 1965	49.60	0.000299	349.81	1.64	46.35	0.000252	264.28	2.18	45.66	0.000246	231.04	2.34
1957 TO 1966	1957 TO 1966	49.22	0.000270	348.47	1.65	46.45	0.000239	274.47	2.09	45.95	0.000238	244.82	2.21
1958 TO 1967	1958 TO 1967	48.10	0.000243	348.26	1.65	46.13	0.000227	289.40	1.97	0.00	0.000000	0.00	0.00
1959 TO 1968	1959 TO 1968	50.32	0.000229	348.76	1.65	48.13	0.000219	291.91	1.95	0.00	0.000000	0.00	0.00
1960 TO 1969	1960 TO 1969	47.27	0.000277	345.86	1.68	47.20	0.000279	342.13	1.69	0.00	0.000000	0.00	0.00
1961 TO 1970	1961 TO 1970	43.62	0.000357	342.74	1.73	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1962 TO 1971	1962 TO 1971	42.02	0.000417	339.10	1.76	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1963 TO 1972	1963 TO 1972	35.81	0.000653	333.69	1.82	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1964 TO 1973	1964 TO 1973	32.65	0.000840	332.29	1.85	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1965 TO 1974	1965 TO 1974	32.81	0.000816	333.71	1.84	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1966 TO 1975	1966 TO 1975	33.27	0.000783	335.14	1.81	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1967 TO 1976	1967 TO 1976	33.39	0.000728	333.88	1.83	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1968 TO 1977	1968 TO 1977	33.77	0.000689	333.10	1.84	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1969 TO 1978	1969 TO 1978	34.29	0.000617	333.91	1.84	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1970 TO 1979	1970 TO 1979	35.83	0.000537	333.50	1.83	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1971 TO 1980	1971 TO 1980	37.57	0.000492	334.00	1.81	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1972 TO 1981	1972 TO 1981	39.72	0.000423	336.07	1.80	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1973 TO 1982	1973 TO 1982	44.32	0.000337	339.59	1.77	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1974 TO 1983	1974 TO 1983	49.82	0.000273	340.21	1.75	48.90	0.000276	317.98	1.86	0.00	0.000000	0.00	0.00
1975 TO 1984	1975 TO 1984	54.37	0.000230	341.20	1.76	52.19	0.000232	301.76	1.96	0.00	0.000000	0.00	0.00
1976 TO 1985	1976 TO 1985	57.57	0.000209	339.61	1.76	54.29	0.000210	290.13	2.05	0.00	0.000000	0.00	0.00
1977 TO 1986	1977 TO 1986	63.40	0.000198	343.08	1.73	58.40	0.000197	283.37	2.09	0.00	0.000000	0.00	0.00
1978 TO 1987	1978 TO 1987	72.00	0.000174	346.52	1.69	64.33	0.000171	277.49	2.13	0.00	0.000000	0.00	0.00
1979 TO 1988	1979 TO 1988	74.43	0.000176	347.33	1.67	62.57	0.000163	259.70	2.30	0.00	0.000000	0.00	0.00
1980 TO 1989	1980 TO 1989	75.46	0.000176	347.85	1.66	62.41	0.000160	255.59	2.35	0.00	0.000000	0.00	0.00
1981 TO 1990	1981 TO 1990	78.05	0.000200	347.85	1.67	61.61	0.000174	245.89	2.49	0.00	0.000000	0.00	0.00
1982 TO 1991	1982 TO 1991	82.72	0.000187	351.18	1.63	63.55	0.000159	244.69	2.50	0.00	0.000000	0.00	0.00
1983 TO 1992	1983 TO 1992	83.84	0.000203	351.28	1.62	63.36	0.000173	240.68	2.54	0.00	0.000000	0.00	0.00
1984 TO 1993	1984 TO 1993	83.03	0.000245	348.69	1.65	61.87	0.000210	236.81	2.63	0.00	0.000000	0.00	0.00
1985 TO 1994	1985 TO 1994	80.63	0.000282	346.65	1.68	59.78	0.000235	231.68	2.71	0.00	0.000000	0.00	0.00
1986 TO 1995	1986 TO 1995	85.05	0.000255	348.60	1.66	61.70	0.000209	230.97	2.72	0.00	0.000000	0.00	0.00
1987 TO 1996	1987 TO 1996	86.56	0.000231	348.32	1.66	62.89	0.000186	231.37	2.71	0.00	0.000000	0.00	0.00
1988 TO 1997	1988 TO 1997	85.32	0.000254	347.51	1.67	61.88	0.000204	230.27	2.75	0.00	0.000000	0.00	0.00
1989 TO 1998	1989 TO 1998	92.96	0.000215	348.01	1.67	65.79	0.000173	228.77	2.78	0.00	0.000000	0.00	0.00
1990 TO 1999	1990 TO 1999	90.10	0.000245	357.95	1.54	63.62	0.000198	231.86	2.65	0.00	0.000000	0.00	0.00
1991 TO 2000	1991 TO 2000	88.64	0.000252	354.82	1.58	63.77	0.000208	231.31	2.67	0.00	0.000000	0.00	0.00
1992 TO 2001	1992 TO 2001	87.71	0.000262	350.57	1.63	63.29	0.000211	228.31	2.74	0.00	0.000000	0.00	0.00
1993 TO 2002	1993 TO 2002	92.93	0.000237	350.26	1.64	65.83	0.000190	227.11	2.78	0.00	0.000000	0.00	0.00
1994 TO 2003	1994 TO 2003	100.25	0.000204	353.62	1.60	69.55	0.000166	229.35	2.75	0.00	0.000000	0.00	0.00
1995 TO 2004	1995 TO 2004	105.24	0.000196	353.94	1.60	71.53	0.000159	228.58	2.87	70.67	0.000160	217.20	2.87
1996 TO 2005	1996 TO 2005	101.10	0.000196	348.66	1.66	69.83	0.000147	225.55	2.87	69.28	0.000148	217.23	2.93
1997 TO 2006	1997 TO 2006	99.56	0.000189	346.01	1.69	69.43	0.000130	223.98	2.93	68.91	0.000130	216.96	2.99

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SUMMARY OF SHRINKING BANDS

YEAR	YEAR	FIRST DEGREE			SECOND DEGREE			THIRD DEGREE			EQUIV. H CURVE		
		AVERAGE SERVICE LIFE (YEARS)	FIT INDEX	TERMINAL A/L RATIO (PERCENT)	EQUIV. H CURVE	AVERAGE SERVICE LIFE (YEARS)	FIT INDEX	TERMINAL A/L RATIO (PERCENT)	EQUIV. H CURVE	AVERAGE SERVICE LIFE (YEARS)		FIT INDEX	TERMINAL A/L RATIO (PERCENT)
2006	TO 2006	92.99	0.000270	332.84	1.86	68.94	0.000225	218.30	3.19	67.78	0.000225	204.33	3.36
2005	TO 2006	90.72	0.000262	331.23	1.89	67.07	0.000198	215.46	3.27	66.56	0.000199	208.09	3.37
2004	TO 2006	96.15	0.000240	332.31	1.87	68.53	0.000171	215.22	3.31	67.43	0.000171	199.48	3.51
2003	TO 2006	103.24	0.000200	335.64	1.83	71.79	0.000146	217.99	3.21	70.10	0.000145	200.42	3.44
2002	TO 2006	107.44	0.000179	336.47	1.82	73.24	0.000126	217.77	3.21	71.62	0.000125	201.75	3.42
2001	TO 2006	104.02	0.000189	335.99	1.83	71.57	0.000129	217.26	3.22	70.46	0.000129	205.07	3.38
2000	TO 2006	100.21	0.000185	335.78	1.83	70.63	0.000124	218.73	3.17	69.94	0.000125	210.88	3.26
1999	TO 2006	97.25	0.000199	346.01	1.69	68.86	0.000139	224.37	2.91	67.78	0.000139	210.23	3.03
1998	TO 2006	100.32	0.000189	345.38	1.70	69.98	0.000133	223.63	2.93	68.99	0.000133	210.90	3.04
1997	TO 2006	99.56	0.000189	346.01	1.69	69.43	0.000130	223.98	2.93	68.91	0.000130	216.96	2.99
1996	TO 2006	99.76	0.000185	346.34	1.69	69.65	0.000129	224.70	2.91	68.97	0.000129	215.31	2.98
1995	TO 2006	100.59	0.000182	346.46	1.68	69.93	0.000128	225.22	2.90	69.17	0.000128	214.69	2.99
1994	TO 2006	98.71	0.000182	345.97	1.70	69.08	0.000122	223.65	2.91	68.74	0.000122	218.95	2.95
1993	TO 2006	97.24	0.000180	345.02	1.70	68.60	0.000119	225.22	2.90	0.00	0.000000	0.00	0.00
1992	TO 2006	96.61	0.000177	346.25	1.70	68.39	0.000116	225.93	2.88	0.00	0.000000	0.00	0.00
1991	TO 2006	96.94	0.000176	346.10	1.69	68.43	0.000115	225.79	2.87	0.00	0.000000	0.00	0.00
1990	TO 2006	96.48	0.000175	346.69	1.68	68.14	0.000112	225.27	2.86	0.00	0.000000	0.00	0.00
1989	TO 2006	95.79	0.000172	347.10	1.68	68.05	0.000111	227.04	2.84	0.00	0.000000	0.00	0.00
1988	TO 2006	95.25	0.000171	348.04	1.67	67.78	0.000109	227.96	2.82	0.00	0.000000	0.00	0.00
1987	TO 2006	95.80	0.000169	348.13	1.67	68.02	0.000108	227.15	2.82	0.00	0.000000	0.00	0.00
1986	TO 2006	95.92	0.000167	348.72	1.66	68.05	0.000106	227.04	2.81	0.00	0.000000	0.00	0.00
1985	TO 2006	95.57	0.000163	347.91	1.66	68.04	0.000103	228.54	2.80	0.00	0.000000	0.00	0.00
1984	TO 2006	95.56	0.000160	347.95	1.67	68.12	0.000100	228.26	2.80	0.00	0.000000	0.00	0.00
1983	TO 2006	95.08	0.000157	347.61	1.67	68.14	0.000098	229.68	2.78	0.00	0.000000	0.00	0.00
1982	TO 2006	94.63	0.000154	348.21	1.66	68.09	0.000096	229.83	2.77	0.00	0.000000	0.00	0.00
1981	TO 2006	94.21	0.000153	348.70	1.66	68.03	0.000095	230.05	2.76	0.00	0.000000	0.00	0.00
1980	TO 2006	93.75	0.000150	348.27	1.66	68.04	0.000093	231.49	2.74	0.00	0.000000	0.00	0.00
1979	TO 2006	93.33	0.000148	348.78	1.66	68.04	0.000092	231.48	2.72	0.00	0.000000	0.00	0.00
1978	TO 2006	92.75	0.000146	348.79	1.65	68.04	0.000092	232.95	2.70	0.00	0.000000	0.00	0.00
1977	TO 2006	91.98	0.000144	349.54	1.65	68.02	0.000093	234.49	2.68	0.00	0.000000	0.00	0.00
1976	TO 2006	91.25	0.000143	350.15	1.64	67.90	0.000094	234.89	2.65	0.00	0.000000	0.00	0.00
1975	TO 2006	90.90	0.000142	350.37	1.63	67.85	0.000094	236.54	2.63	0.00	0.000000	0.00	0.00
1974	TO 2006	90.41	0.000141	351.18	1.63	67.86	0.000094	236.51	2.61	0.00	0.000000	0.00	0.00
1973	TO 2006	89.09	0.000139	351.89	1.62	67.80	0.000097	239.68	2.56	67.61	0.000098	235.91	2.58
1972	TO 2006	87.72	0.000139	352.82	1.61	67.66	0.000101	241.67	2.52	67.22	0.000102	234.31	2.56
1971	TO 2006	87.31	0.000138	352.20	1.61	67.65	0.000102	243.18	2.50	67.13	0.000102	234.61	2.55
1970	TO 2006	86.87	0.000138	352.83	1.60	67.61	0.000103	243.30	2.49	67.02	0.000103	233.53	2.55
1969	TO 2006	86.58	0.000137	352.86	1.60	67.60	0.000102	243.34	2.48	66.98	0.000103	233.67	2.54
1968	TO 2006	86.56	0.000136	352.94	1.60	67.62	0.000102	244.75	2.48	66.99	0.000102	233.63	2.54
1967	TO 2006	86.44	0.000136	353.44	1.60	67.60	0.000102	244.83	2.47	66.94	0.000102	233.79	2.54
1966	TO 2006	86.36	0.000136	352.60	1.60	67.57	0.000102	244.92	2.47	66.90	0.000102	233.93	2.54
1965	TO 2006	86.24	0.000136	353.07	1.60	67.52	0.000102	245.13	2.47	66.84	0.000102	232.64	2.54
1964	TO 2006	86.14	0.000136	353.49	1.60	67.48	0.000102	245.27	2.47	66.80	0.000102	232.79	2.54
1963	TO 2006	86.08	0.000136	353.73	1.60	67.42	0.000102	243.99	2.47	66.74	0.000102	232.99	2.54
1962	TO 2006	86.03	0.000136	352.78	1.60	67.37	0.000102	244.18	2.47	66.70	0.000102	233.13	2.54
1961	TO 2006	85.98	0.000136	352.98	1.60	67.32	0.000102	244.34	2.47	66.66	0.000102	233.27	2.54
1960	TO 2006	85.96	0.000136	353.05	1.60	67.29	0.000102	244.45	2.47	66.64	0.000102	233.34	2.54
1959	TO 2006	85.93	0.000137	353.19	1.60	67.26	0.000102	244.56	2.47	66.61	0.000102	233.44	2.54
1958	TO 2006	85.88	0.000137	353.40	1.60	67.23	0.000102	244.67	2.47	66.58	0.000102	233.54	2.54
1957	TO 2006	85.86	0.000137	353.50	1.60	67.22	0.000102	244.71	2.47	66.57	0.000102	233.58	2.54
1956	TO 2006	85.84	0.000137	353.58	1.60	67.20	0.000102	244.77	2.47	66.56	0.000102	233.63	2.54
1955	TO 2006	85.82	0.000137	353.63	1.60	67.19	0.000102	244.82	2.47	66.54	0.000103	233.68	2.54
1954	TO 2006	85.79	0.000137	353.78	1.60	67.16	0.000102	244.94	2.47	66.52	0.000103	233.76	2.54

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SUMMARY OF SHRINKING BANDS

YEAR	YEAR	FIRST DEGREE			SECOND DEGREE			THIRD DEGREE					
		AVERAGE SERVICE LIFE (YEARS)	FIT INDEX	TERMINAL A/L RATIO (PERCENT)	EQUIV. H CURVE	AVERAGE SERVICE LIFE (YEARS)	FIT INDEX	TERMINAL A/L RATIO (PERCENT)	EQUIV. H CURVE	AVERAGE SERVICE LIFE (YEARS)	FIT INDEX	TERMINAL A/L RATIO (PERCENT)	EQUIV. H CURVE
1953 TO 2006		85.78	0.000137	353.83	1.60	67.15	0.000103	244.98	2.47	66.51	0.000103	233.79	2.54
1952 TO 2006		85.76	0.000137	353.88	1.60	67.14	0.000103	245.02	2.47	66.50	0.000103	233.83	2.54

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ACCOUNT 2381000 METERS

SUMMARY OF ROLLING BANDS

YEAR	YEAR	FIRST DEGREE				SECOND DEGREE				THIRD DEGREE			
		AVERAGE SERVICE LIFE (YEARS)	FIT INDEX	TERMINAL A/L RATIO (PERCENT)	EQUIV. H CURVE	AVERAGE SERVICE LIFE (YEARS)	FIT INDEX	TERMINAL A/L RATIO (PERCENT)	EQUIV. H CURVE	AVERAGE SERVICE LIFE (YEARS)	FIT INDEX	TERMINAL A/L RATIO (PERCENT)	EQUIV. H CURVE
1952 TO 1961	1952 TO 1961	24.32	0.002417	302.27	2.23	26.53	0.001994	220.54	3.07	0.00	0.000000	0.00	0.00
1953 TO 1962	1953 TO 1962	23.00	0.002543	302.14	2.26	25.41	0.002042	222.36	3.08	0.00	0.000000	0.00	0.00
1954 TO 1963	1954 TO 1963	21.79	0.002455	300.65	2.23	23.87	0.001999	228.27	2.84	0.00	0.000000	0.00	0.00
1955 TO 1964	1955 TO 1964	20.53	0.002945	304.49	2.18	22.08	0.002619	242.25	2.54	0.00	0.000000	0.00	0.00
1956 TO 1965	1956 TO 1965	20.14	0.002892	305.34	2.21	21.64	0.002530	242.61	2.58	0.00	0.000000	0.00	0.00
1957 TO 1966	1957 TO 1966	20.51	0.002748	304.70	2.20	21.84	0.002308	240.41	2.59	0.00	0.000000	0.00	0.00
1958 TO 1967	1958 TO 1967	20.62	0.002729	303.14	2.23	21.90	0.002055	230.57	2.68	0.00	0.000000	0.00	0.00
1959 TO 1968	1959 TO 1968	21.22	0.002821	299.25	2.26	22.25	0.002018	222.46	2.80	0.00	0.000000	0.00	0.00
1960 TO 1969	1960 TO 1969	22.09	0.002860	301.00	2.25	22.63	0.001981	218.76	2.87	0.00	0.000000	0.00	0.00
1961 TO 1970	1961 TO 1970	21.89	0.002956	299.19	2.29	22.07	0.001747	215.18	2.96	0.00	0.000000	0.00	0.00
1962 TO 1971	1962 TO 1971	23.73	0.002833	301.29	2.24	22.95	0.001646	211.29	3.02	0.00	0.000000	206.62	3.02
1963 TO 1972	1963 TO 1972	23.59	0.002866	303.15	2.25	22.67	0.001905	213.96	3.03	0.00	0.000000	0.00	0.00
1964 TO 1973	1964 TO 1973	24.12	0.002837	300.54	2.27	23.03	0.001993	210.61	3.18	0.00	0.000000	0.00	0.00
1965 TO 1974	1965 TO 1974	25.06	0.002651	301.27	2.28	23.65	0.001783	205.06	3.37	0.00	0.000000	0.00	0.00
1966 TO 1975	1966 TO 1975	25.97	0.002592	302.33	2.27	24.15	0.001768	204.99	3.41	0.00	0.000000	0.00	0.00
1967 TO 1976	1967 TO 1976	26.41	0.002552	301.03	2.30	24.43	0.001656	202.58	3.50	0.00	0.000000	0.00	0.00
1968 TO 1977	1968 TO 1977	28.66	0.001959	305.34	2.19	25.76	0.001321	207.72	3.28	0.00	0.000000	0.00	0.00
1969 TO 1978	1969 TO 1978	29.98	0.001813	308.57	2.17	26.78	0.001326	210.99	3.19	0.00	0.000000	0.00	0.00
1970 TO 1979	1970 TO 1979	31.14	0.001656	309.94	2.16	27.74	0.001254	210.91	3.16	0.00	0.000000	0.00	0.00
1971 TO 1980	1971 TO 1980	34.13	0.001498	312.02	2.11	29.41	0.001104	209.08	3.15	0.00	0.000000	0.00	0.00
1972 TO 1981	1972 TO 1981	35.29	0.001345	315.98	2.09	30.30	0.000954	212.89	3.12	0.00	0.000000	0.00	0.00
1973 TO 1982	1973 TO 1982	38.92	0.001380	317.32	2.05	31.96	0.000974	208.09	3.20	0.00	0.000000	0.00	0.00
1974 TO 1983	1974 TO 1983	42.70	0.001237	322.03	1.99	33.93	0.000899	207.76	3.18	0.00	0.000000	0.00	0.00
1975 TO 1984	1975 TO 1984	46.49	0.001040	323.73	1.98	36.13	0.000758	208.94	3.23	0.00	0.000000	0.00	0.00
1976 TO 1985	1976 TO 1985	46.25	0.001146	318.93	2.04	36.28	0.000842	205.33	3.33	0.00	0.000000	0.00	0.00
1977 TO 1986	1977 TO 1986	46.47	0.001205	317.42	2.07	36.52	0.000855	201.27	3.39	36.45	0.000865	198.88	3.43
1978 TO 1987	1978 TO 1987	47.29	0.001298	314.03	2.12	37.69	0.001013	202.99	3.53	37.20	0.001020	184.13	3.90
1979 TO 1988	1979 TO 1988	47.16	0.001332	310.62	2.14	37.66	0.000964	200.50	3.60	37.10	0.000951	176.55	4.19
1980 TO 1989	1980 TO 1989	47.21	0.001585	312.46	2.13	37.13	0.001108	195.26	3.60	36.65	0.001053	170.55	4.37
1981 TO 1990	1981 TO 1990	44.37	0.002057	309.87	2.17	35.67	0.001430	192.05	3.56	35.58	0.001349	167.24	4.39
1982 TO 1991	1982 TO 1991	43.28	0.002080	308.47	2.17	35.64	0.001419	192.17	3.59	35.64	0.001349	166.95	4.40
1983 TO 1992	1983 TO 1992	42.99	0.002055	308.21	2.20	35.91	0.001384	190.75	3.59	35.92	0.001321	168.42	4.39
1984 TO 1993	1984 TO 1993	42.28	0.002051	303.90	2.20	36.02	0.001357	190.15	3.62	36.11	0.001315	167.53	4.37
1985 TO 1994	1985 TO 1994	39.51	0.002352	299.96	2.23	35.10	0.001555	189.48	3.63	35.40	0.001522	168.06	4.37
1986 TO 1995	1986 TO 1995	38.34	0.002436	298.68	2.31	34.85	0.001554	187.95	3.65	35.23	0.001528	168.90	4.34
1987 TO 1996	1987 TO 1996	38.99	0.002307	301.36	2.29	35.51	0.001465	187.29	3.67	35.82	0.001449	171.67	4.31
1988 TO 1997	1988 TO 1997	39.72	0.001991	303.39	2.25	36.41	0.001254	180.91	3.66	36.55	0.001259	176.46	4.11
1989 TO 1998	1989 TO 1998	37.87	0.002203	299.74	2.29	35.72	0.001254	188.95	3.67	36.00	0.001366	176.41	4.12
1990 TO 1999	1990 TO 1999	38.45	0.001925	300.41	2.28	36.53	0.001358	189.91	3.67	36.66	0.001227	181.39	3.98
1991 TO 2000	1991 TO 2000	40.91	0.001557	304.34	2.23	38.38	0.001051	196.73	3.67	38.38	0.001064	191.52	3.77
1992 TO 2001	1992 TO 2001	43.32	0.001344	308.17	2.19	40.14	0.000990	200.56	3.58	0.00	0.000000	0.00	0.00
1993 TO 2002	1993 TO 2002	40.21	0.001261	307.16	2.21	38.65	0.000846	205.69	3.42	38.62	0.000854	200.68	3.48
1994 TO 2003	1994 TO 2003	41.24	0.001245	306.72	2.21	39.46	0.000870	206.53	3.39	39.42	0.000877	199.14	3.47
1995 TO 2004	1995 TO 2004	33.95	0.002879	298.99	2.29	34.32	0.002541	208.35	3.03	0.00	0.000000	0.00	0.00
1996 TO 2005	1996 TO 2005	35.23	0.002633	302.33	2.27	35.09	0.002357	212.28	2.93	0.00	0.000000	0.00	0.00
1997 TO 2006	1997 TO 2006	33.51	0.002635	299.93	2.29	33.58	0.002199	212.93	2.75	0.00	0.000000	0.00	0.00

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SUMMARY OF SHRINKING BANDS

YEAR	YEAR	AVERAGE SERVICE LIFE (YEARS)	FIRST DEGREE			SECOND DEGREE			THIRD DEGREE			EQUIV. H CURVE	
			FIT INDEX	TERMINAL A/L RATIO (PERCENT)	EQUIV. H CURVE	AVERAGE SERVICE LIFE (YEARS)	FIT INDEX	TERMINAL A/L RATIO (PERCENT)	EQUIV. H CURVE	AVERAGE SERVICE LIFE (YEARS)	FIT INDEX		TERMINAL A/L RATIO (PERCENT)
2006	TO 2006	27.77	0.005244	289.83	2.47	26.91	0.004093	224.81	1.74	27.50	0.004035	212.75	1.84
2005	TO 2006	34.03	0.003252	298.22	2.32	32.37	0.002630	217.77	2.17	32.97	0.002603	198.65	2.33
2004	TO 2006	26.02	0.006742	282.48	2.53	25.61	0.006361	236.26	1.94	0.00	0.000000	0.00	0.00
2003	TO 2006	28.51	0.004987	289.40	2.47	28.25	0.004572	228.31	2.12	0.00	0.000000	0.00	0.00
2002	TO 2006	28.71	0.004132	290.80	2.44	28.65	0.003727	228.60	2.21	0.00	0.000000	0.00	0.00
2001	TO 2006	30.51	0.003646	293.30	2.37	30.43	0.003274	225.09	2.34	0.00	0.000000	0.00	0.00
2000	TO 2006	32.05	0.003282	298.02	2.32	31.90	0.002923	221.04	2.46	0.00	0.000000	0.00	0.00
1999	TO 2006	32.90	0.002996	299.41	2.30	32.75	0.002626	218.29	2.56	0.00	0.000000	0.00	0.00
1998	TO 2006	32.76	0.002807	297.64	2.33	32.95	0.002381	213.94	2.69	0.00	0.000000	0.00	0.00
1997	TO 2006	33.51	0.002635	299.93	2.29	33.58	0.002199	212.93	2.75	0.00	0.000000	0.00	0.00
1996	TO 2006	34.02	0.002503	301.30	2.29	34.05	0.002038	209.99	2.83	34.05	0.002053	209.96	2.83
1995	TO 2006	33.96	0.002439	298.86	2.30	34.11	0.001956	209.65	2.89	34.11	0.001970	209.64	2.90
1994	TO 2006	33.84	0.002425	299.93	2.31	34.09	0.001929	206.81	2.95	0.00	0.000000	0.00	0.00
1993	TO 2006	34.11	0.002378	300.46	2.31	34.31	0.001870	205.46	3.00	34.31	0.001884	205.46	3.05
1992	TO 2006	34.36	0.002339	298.30	2.30	34.48	0.001817	204.47	3.04	34.48	0.001830	204.47	3.09
1991	TO 2006	34.54	0.002289	299.67	2.31	34.61	0.001751	203.68	3.08	34.61	0.001764	203.68	3.10
1990	TO 2006	34.56	0.002281	299.44	2.31	34.60	0.001714	203.78	3.10	34.59	0.001727	203.79	3.11
1989	TO 2006	34.76	0.002273	300.63	2.30	34.68	0.001683	203.28	3.12	34.68	0.001695	200.39	3.13
1988	TO 2006	34.93	0.002247	299.19	2.31	34.77	0.001647	202.77	3.15	34.78	0.001659	199.84	3.17
1987	TO 2006	35.17	0.002234	299.95	2.31	34.90	0.001624	202.03	3.17	34.92	0.001636	199.02	3.20
1986	TO 2006	35.27	0.002205	299.12	2.31	34.92	0.001592	201.87	3.19	34.95	0.001604	198.83	3.22
1985	TO 2006	35.34	0.002177	298.49	2.31	34.94	0.001564	201.79	3.20	34.97	0.001576	198.75	3.23
1984	TO 2006	35.53	0.002159	299.78	2.31	35.01	0.001544	201.37	3.21	35.05	0.001556	198.28	3.25
1983	TO 2006	35.66	0.002142	298.62	2.30	35.05	0.001526	201.11	3.22	35.10	0.001538	198.00	3.27
1982	TO 2006	35.75	0.002133	300.67	2.30	35.08	0.001518	200.98	3.23	35.13	0.001529	197.85	3.28
1981	TO 2006	35.85	0.002117	299.83	2.30	35.11	0.001500	200.78	3.24	35.17	0.001512	194.77	3.30
1980	TO 2006	35.92	0.002101	299.24	2.30	35.13	0.001484	200.71	3.24	35.18	0.001495	194.69	3.30
1979	TO 2006	35.95	0.002081	299.02	2.31	35.11	0.001467	200.77	3.25	35.17	0.001478	197.60	3.30
1978	TO 2006	35.96	0.002062	298.96	2.31	35.09	0.001451	200.90	3.24	35.15	0.001462	197.74	3.30
1977	TO 2006	35.99	0.002051	298.69	2.30	35.05	0.001435	201.17	3.22	35.09	0.001446	198.04	3.27
1976	TO 2006	35.95	0.002030	299.02	2.29	35.01	0.001419	201.36	3.22	35.05	0.001430	198.26	3.27
1975	TO 2006	35.92	0.002011	299.32	2.29	34.98	0.001407	201.56	3.22	35.01	0.001417	198.51	3.26
1974	TO 2006	35.86	0.001994	299.81	2.28	34.92	0.001396	201.91	3.20	34.94	0.001405	198.94	3.24
1973	TO 2006	35.77	0.001973	300.50	2.28	34.85	0.001385	202.29	3.19	34.86	0.001393	199.38	3.23
1972	TO 2006	35.64	0.001944	301.63	2.27	34.74	0.001372	202.92	3.17	34.74	0.001380	200.07	3.20
1971	TO 2006	35.68	0.001936	301.33	2.27	34.77	0.001365	202.78	3.16	34.76	0.001372	199.93	3.21
1970	TO 2006	35.57	0.001913	302.24	2.26	34.68	0.001355	206.19	3.16	34.67	0.001362	200.45	3.19
1969	TO 2006	35.55	0.001904	302.39	2.26	34.66	0.001349	206.31	3.15	34.65	0.001356	200.56	3.18
1968	TO 2006	35.51	0.001896	302.73	2.26	34.63	0.001343	206.46	3.15	34.63	0.001350	200.71	3.18
1967	TO 2006	35.43	0.001889	303.43	2.26	34.57	0.001334	203.92	3.15	34.57	0.001341	201.04	3.18
1966	TO 2006	35.41	0.001887	303.55	2.25	34.54	0.001331	206.98	3.14	34.54	0.001338	201.21	3.17
1965	TO 2006	35.37	0.001882	303.92	2.25	34.50	0.001327	207.22	3.13	34.50	0.001335	201.45	3.16
1964	TO 2006	35.30	0.001866	304.51	2.24	34.40	0.001320	207.86	3.09	34.39	0.001334	202.07	3.13
1963	TO 2006	35.24	0.001884	305.02	2.23	34.33	0.001326	205.36	3.07	34.33	0.001332	202.47	3.11
1962	TO 2006	35.18	0.001883	305.53	2.23	34.30	0.001325	205.56	3.08	34.29	0.001331	202.66	3.11
1961	TO 2006	35.13	0.001882	305.99	2.23	34.27	0.001324	205.72	3.08	34.27	0.001330	202.83	3.11
1960	TO 2006	35.09	0.001877	303.52	2.23	34.25	0.001319	205.84	3.08	34.25	0.001325	202.95	3.11
1959	TO 2006	35.04	0.001876	303.92	2.23	34.23	0.001318	205.97	3.08	34.22	0.001324	203.08	3.11
1958	TO 2006	34.99	0.001873	304.39	2.23	34.20	0.001315	206.15	3.08	34.19	0.001322	203.25	3.11
1957	TO 2006	34.93	0.001870	304.92	2.23	34.17	0.001312	206.34	3.08	34.16	0.001319	203.44	3.11
1956	TO 2006	34.90	0.001870	305.18	2.23	34.15	0.001310	206.43	3.08	34.15	0.001317	203.53	3.11
1955	TO 2006	34.90	0.001867	305.17	2.23	34.15	0.001310	206.41	3.08	34.15	0.001317	203.52	3.11
1954	TO 2006	34.91	0.001865	305.05	2.23	34.16	0.001308	206.35	3.08	34.16	0.001315	203.46	3.11

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SUMMARY OF SHRINKING BANDS

YEAR	YEAR	FIRST DEGREE				SECOND DEGREE				THIRD DEGREE			
		AVERAGE SERVICE LIFE (YEARS)	FIT INDEX	TERMINAL A/L RATIO (PERCENT)	EQUIV. H CURVE	AVERAGE SERVICE LIFE (YEARS)	FIT INDEX	TERMINAL A/L RATIO (PERCENT)	EQUIV. H CURVE	AVERAGE SERVICE LIFE (YEARS)	FIT INDEX	TERMINAL A/L RATIO (PERCENT)	EQUIV. H CURVE
1953 TO 2006		34.92	0.001865	304.95	2.23	34.17	0.001307	206.31	3.08	34.17	0.001315	203.42	3.11
1952 TO 2006		34.93	0.001865	304.86	2.23	34.18	0.001307	206.27	3.09	34.17	0.001315	203.38	3.11

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ACCOUNT 2382000 METER INSTALLATIONS

SUMMARY OF ROLLING BANDS

YEAR	YEAR	FIRST DEGREE				SECOND DEGREE				THIRD DEGREE			
		AVERAGE SERVICE LIFE (YEARS)	FIT INDEX	TERMINAL A/L RATIO (PERCENT)	EQUIV. H CURVE	AVERAGE SERVICE LIFE (YEARS)	FIT INDEX	TERMINAL A/L RATIO (PERCENT)	EQUIV. H CURVE	AVERAGE SERVICE LIFE (YEARS)	FIT INDEX	TERMINAL A/L RATIO (PERCENT)	EQUIV. H CURVE
1975 TO 1984		28.79	0.005450	300.40	2.29	25.35	0.004735	187.41	3.68	0.00	0.000000	0.00	0.00
1976 TO 1985		28.73	0.005865	294.13	2.36	25.18	0.005064	184.67	3.86	0.00	0.000000	0.00	0.00
1977 TO 1986		29.54	0.005305	296.20	2.33	25.47	0.004548	182.54	3.89	0.00	0.000000	0.00	0.00
1978 TO 1987		30.57	0.004538	299.27	2.29	25.85	0.003738	183.77	3.89	25.87	0.003761	183.60	3.91
1979 TO 1988		32.90	0.003600	305.46	2.23	27.03	0.002975	186.80	3.92	27.08	0.002986	182.78	3.99
1980 TO 1989		36.64	0.002877	309.81	2.15	28.88	0.002453	188.70	3.89	28.90	0.002471	181.65	4.04
1981 TO 1990		38.97	0.002532	311.78	2.12	30.18	0.002195	190.51	3.85	30.12	0.002210	180.92	4.14
1982 TO 1991		41.18	0.002273	314.48	2.10	31.56	0.002015	194.89	3.81	31.35	0.002028	180.22	4.21
1983 TO 1992		47.05	0.001761	319.89	2.04	34.45	0.001595	195.93	3.73	33.80	0.001603	176.04	4.30
1984 TO 1993		50.83	0.001438	321.64	2.01	36.66	0.001312	200.48	3.67	35.87	0.001321	182.60	4.11
1985 TO 1994		58.49	0.000929	325.68	1.96	40.58	0.000837	205.75	3.55	40.31	0.000844	199.70	3.64
1986 TO 1995		69.42	0.000568	330.62	1.89	46.06	0.000510	211.70	3.39	0.00	0.000000	0.00	0.00
1987 TO 1996		81.63	0.000432	333.84	1.84	51.51	0.000396	214.51	3.31	0.00	0.000000	0.00	0.00
1988 TO 1997		91.36	0.000361	336.56	1.82	56.38	0.000339	217.27	3.23	0.00	0.000000	0.00	0.00
1989 TO 1998		103.93	0.000309	339.18	1.78	62.29	0.000297	219.14	3.15	0.00	0.000000	0.00	0.00
1990 TO 1999		112.17	0.000252	340.10	1.77	69.02	0.000246	225.28	3.01	0.00	0.000000	0.00	0.00
1991 TO 2000		147.51	0.000182	270.15	1.72	83.19	0.000180	228.99	2.93	0.00	0.000000	0.00	0.00
1992 TO 2001		167.59	0.000148	237.78	1.71	97.19	0.000148	235.11	2.79	0.00	0.000000	0.00	0.00
1993 TO 2002		171.11	0.000136	232.89	1.64	125.09	0.000137	260.21	2.32	0.00	0.000000	0.00	0.00
1994 TO 2003		216.77	0.000110	183.83	1.78	0.00	0.000000	0.00	0.00	100.72	0.000111	184.17	3.58
1995 TO 2004		32.16	0.002063	296.98	2.34	31.81	0.002032	234.23	2.90	0.00	0.000000	0.00	0.00
1996 TO 2005		33.07	0.001895	297.82	2.31	32.61	0.001886	240.72	2.78	0.00	0.000000	0.00	0.00
1997 TO 2006		33.48	0.001800	300.19	2.28	32.98	0.001790	241.08	2.74	0.00	0.000000	0.00	0.00

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SUMMARY OF SHRINKING BANDS

YEAR	YEAR	FIRST DEGREE			SECOND DEGREE			THIRD DEGREE		
		AVERAGE SERVICE LIFE (YEARS)	FIT INDEX	TERMINAL A/L RATIO (PERCENT)	EQUIV. H CURVE	AVERAGE SERVICE LIFE (YEARS)	FIT INDEX	TERMINAL A/L RATIO (PERCENT)	EQUIV. H CURVE	EQUIV. H CURVE
2006	TO 2006	53.14	0.001324	339.67	1.75	41.45	0.001023	208.69	2.79	0.000756
2005	TO 2006	68.77	0.000791	349.69	1.63	47.98	0.000632	211.57	2.86	0.000510
2004	TO 2006	22.83	0.005188	278.16	2.61	23.10	0.005243	261.85	2.68	0.000000
2003	TO 2006	25.47	0.003660	284.59	2.50	25.72	0.003701	262.46	2.61	0.000000
2002	TO 2006	27.43	0.002935	289.78	2.42	27.61	0.002965	262.55	2.58	0.000000
2001	TO 2006	29.11	0.002549	293.67	2.37	29.21	0.002571	258.49	2.59	0.000000
2000	TO 2006	30.52	0.002299	296.54	2.34	30.49	0.002313	254.15	2.62	0.000000
1999	TO 2006	31.67	0.002105	298.39	2.31	31.50	0.002111	249.22	2.66	0.000000
1998	TO 2006	32.65	0.001937	298.62	2.29	32.32	0.001935	246.01	2.70	0.000000
1997	TO 2006	33.48	0.001800	300.19	2.28	32.98	0.001790	241.08	2.74	0.000000
1996	TO 2006	34.16	0.001686	302.99	2.27	33.49	0.001668	240.37	2.78	0.000000
1995	TO 2006	34.70	0.001597	303.99	2.25	33.88	0.001571	237.63	2.81	0.000000
1994	TO 2006	35.17	0.001531	302.83	2.25	34.19	0.001498	235.44	2.85	0.000000
1993	TO 2006	35.53	0.001475	305.37	2.24	34.42	0.001434	233.85	2.88	0.000000
1992	TO 2006	35.84	0.001424	305.51	2.24	34.61	0.001377	229.67	2.91	0.000000
1991	TO 2006	36.11	0.001379	305.99	2.23	34.77	0.001325	228.64	2.94	0.000000
1990	TO 2006	36.23	0.001351	305.00	2.23	34.82	0.001292	228.33	2.96	0.000000
1989	TO 2006	36.43	0.001324	306.03	2.22	34.92	0.001258	227.66	2.98	0.000000
1988	TO 2006	36.57	0.001304	304.92	2.21	34.98	0.001233	227.29	2.99	0.000000
1987	TO 2006	36.68	0.001290	306.71	2.21	35.02	0.001215	227.01	3.01	0.000000
1986	TO 2006	36.67	0.001284	306.80	2.20	34.98	0.001212	224.41	3.02	0.000000
1985	TO 2006	36.57	0.001284	307.65	2.20	34.88	0.001202	225.03	3.03	0.000000
1984	TO 2006	36.47	0.001285	305.74	2.21	34.79	0.001200	225.62	3.04	0.000000
1983	TO 2006	36.46	0.001284	305.83	2.21	34.77	0.001198	222.92	3.05	0.000000
1982	TO 2006	36.30	0.001293	307.18	2.21	34.64	0.001206	223.72	3.05	0.000000
1981	TO 2006	36.34	0.001288	306.81	2.21	34.66	0.001199	223.63	3.05	0.000000
1980	TO 2006	36.25	0.001292	304.79	2.21	34.59	0.001203	224.08	3.05	0.000000
1979	TO 2006	36.13	0.001300	305.86	2.21	34.49	0.001209	224.72	3.06	0.000000
1978	TO 2006	36.05	0.001303	306.53	2.22	34.42	0.001208	222.25	3.07	0.000000
1977	TO 2006	36.10	0.001298	306.14	2.21	34.44	0.001203	222.10	3.08	0.000000
1976	TO 2006	36.06	0.001290	306.43	2.21	34.41	0.001189	222.32	3.08	0.000000
1975	TO 2006	36.05	0.001288	306.53	2.20	34.37	0.001186	222.55	3.08	0.000000

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SUMMARY OF ROLLING BANDS

YEAR	YEAR	FIRST DEGREE				SECOND DEGREE				THIRD DEGREE			
		AVERAGE SERVICE LIFE (YEARS)	FIT INDEX	TERMINAL A/L RATIO (PERCENT)	EQUIV. H CURVE	AVERAGE SERVICE LIFE (YEARS)	FIT INDEX	TERMINAL A/L RATIO (PERCENT)	EQUIV. H CURVE	AVERAGE SERVICE LIFE (YEARS)	FIT INDEX	TERMINAL A/L RATIO (PERCENT)	EQUIV. H CURVE
1975 TO 1984		0.00	0.000000	0.00	0.00	93.11	0.001684	204.60	2.60	0.00	0.000000	0.00	0.00
1976 TO 1985		0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00	59.52	0.001761	168.86	2.95
1977 TO 1986		0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00	57.46	0.001666	167.93	3.01
1978 TO 1987		0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00	57.24	0.001606	168.58	3.04
1979 TO 1988		0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00	57.75	0.001561	168.82	3.06
1980 TO 1989		0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00	55.67	0.001512	167.94	3.19
1981 TO 1990		0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00	56.26	0.001461	166.19	3.29
1982 TO 1991		0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00	56.98	0.001080	165.84	3.40
1983 TO 1992		68.65	0.002334	385.26	1.22	41.97	0.002296	213.25	2.83	39.26	0.002308	182.14	3.17
1984 TO 1993		68.80	0.001880	339.38	1.77	45.69	0.001846	206.84	3.40	43.75	0.001864	184.02	3.80
1985 TO 1994		51.93	0.004244	324.50	1.97	37.52	0.004087	190.57	3.80	36.31	0.004020	155.61	4.92
1986 TO 1995		55.72	0.003937	329.31	1.90	38.86	0.003810	191.71	3.77	37.30	0.003755	156.86	4.95
1987 TO 1996		58.58	0.003644	332.04	1.88	40.48	0.003551	193.91	3.75	38.47	0.003512	157.27	5.10
1988 TO 1997		61.84	0.002616	333.90	1.84	42.48	0.002524	196.56	3.75	39.80	0.002476	159.55	5.10
1989 TO 1998		65.09	0.002407	335.69	1.82	44.49	0.002345	198.93	3.70	41.31	0.002317	160.98	5.00
1990 TO 1999		68.91	0.002269	335.94	1.81	46.57	0.002227	200.75	3.64	43.02	0.002215	161.56	4.96
1991 TO 2000		72.46	0.001947	337.44	1.80	48.88	0.001916	203.55	3.56	44.92	0.001911	165.87	4.82
1992 TO 2001		76.45	0.001476	339.42	1.78	51.53	0.001449	206.66	3.48	47.04	0.001446	169.00	4.63
1993 TO 2002		108.89	0.001180	343.02	1.73	60.64	0.001170	208.62	3.49	50.96	0.001160	161.88	5.10
1994 TO 2003		34.65	0.004087	304.47	2.23	33.82	0.003355	181.86	3.92	35.57	0.003006	150.39	5.10
1995 TO 2004		36.64	0.003394	307.05	2.20	34.74	0.002767	185.66	3.93	36.27	0.002522	153.01	5.10
1996 TO 2005		30.91	0.004184	296.00	2.34	31.68	0.003091	181.53	3.83	34.09	0.002609	151.07	5.10
1997 TO 2006		31.48	0.003974	297.04	2.34	31.66	0.002913	181.60	3.82	34.09	0.002423	151.07	5.10

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SUMMARY OF SHRINKING BANDS

YEAR	YEAR	FIRST DEGREE			SECOND DEGREE			THIRD DEGREE			EQUIV. H CURVE		
		AVERAGE SERVICE LIFE (YEARS)	FIT INDEX	TERMINAL A/L RATIO (PERCENT)	EQUIV. H CURVE	AVERAGE SERVICE LIFE (YEARS)	FIT INDEX	TERMINAL A/L RATIO (PERCENT)	EQUIV. H CURVE	AVERAGE SERVICE LIFE (YEARS)		FIT INDEX	TERMINAL A/L RATIO (PERCENT)
2006	TO 2006	399.00	0.000000	99.87	5.10	399.00	0.000000	99.87	5.10	399.00	0.000000	99.87	5.10
2005	TO 2006	25.28	0.007765	274.97	2.65	25.39	0.005535	179.17	2.98	29.63	0.004179	143.42	5.10
2004	TO 2006	29.17	0.005510	289.67	2.47	28.29	0.004209	182.04	3.41	31.51	0.003567	150.73	5.10
2003	TO 2006	23.23	0.007637	273.35	2.70	25.64	0.004751	177.43	3.17	29.47	0.003632	147.60	5.10
2002	TO 2006	25.30	0.005867	282.58	2.56	27.63	0.003750	179.17	3.52	30.82	0.003016	150.87	5.10
2001	TO 2006	27.01	0.005079	286.94	2.47	28.98	0.003438	181.14	3.72	31.89	0.002848	152.08	5.10
2000	TO 2006	28.42	0.004730	290.26	2.42	29.92	0.003376	182.13	3.76	32.69	0.002877	151.41	5.10
1999	TO 2006	29.60	0.004399	292.23	2.40	30.63	0.003178	181.17	3.76	33.31	0.002694	151.62	5.10
1998	TO 2006	30.60	0.004181	295.72	2.37	31.20	0.003060	181.08	3.78	33.76	0.002584	152.55	5.10
1997	TO 2006	31.48	0.003974	297.04	2.34	31.66	0.002913	181.60	3.82	34.09	0.002423	151.07	5.10
1996	TO 2006	32.22	0.003892	299.54	2.32	32.00	0.002858	182.82	3.82	34.33	0.002405	150.01	5.10
1995	TO 2006	32.84	0.003824	299.96	2.30	32.25	0.002860	181.42	3.81	34.47	0.002377	152.29	5.10
1994	TO 2006	32.79	0.004000	300.36	2.30	32.16	0.003047	181.88	3.80	34.41	0.002544	149.66	5.10
1993	TO 2006	33.31	0.003943	301.75	2.29	32.38	0.003021	183.78	3.81	34.54	0.002538	149.12	5.10
1992	TO 2006	33.20	0.003894	299.71	2.28	32.30	0.002968	181.11	3.81	34.40	0.002523	149.72	5.10
1991	TO 2006	33.61	0.003839	302.01	2.27	32.45	0.002927	183.35	3.82	34.48	0.002486	152.28	5.10
1990	TO 2006	33.96	0.003808	302.81	2.27	32.56	0.002909	182.74	3.83	34.53	0.002474	152.02	5.10
1989	TO 2006	34.25	0.003777	302.22	2.26	32.64	0.002889	182.28	3.84	34.57	0.002459	151.89	5.10
1988	TO 2006	34.50	0.003755	302.86	2.26	32.70	0.002873	181.97	3.83	34.59	0.002445	151.76	5.10
1987	TO 2006	34.73	0.003736	300.93	2.26	32.77	0.002848	181.57	3.83	34.63	0.002426	151.65	5.10
1986	TO 2006	34.91	0.003720	302.16	2.26	32.78	0.002840	181.52	3.82	34.62	0.002397	151.63	5.10
1985	TO 2006	35.02	0.003702	304.09	2.26	32.80	0.002820	184.46	3.82	34.62	0.002391	152.11	5.10
1984	TO 2006	35.16	0.003679	302.88	2.26	32.80	0.002815	184.85	3.76	34.51	0.002380	152.11	5.10
1983	TO 2006	35.19	0.003666	305.52	2.23	32.73	0.002815	184.77	3.77	34.51	0.002380	152.11	5.10
1982	TO 2006	35.29	0.003650	304.62	2.23	32.74	0.002804	184.77	3.77	34.51	0.002371	152.11	5.10
1981	TO 2006	35.37	0.003637	303.89	2.23	32.75	0.002795	184.72	3.77	34.51	0.002371	152.11	5.10
1980	TO 2006	35.44	0.003625	303.33	2.23	32.75	0.002786	184.72	3.77	34.51	0.002362	152.11	5.10
1979	TO 2006	35.48	0.003613	305.83	2.23	32.75	0.002778	184.75	3.77	34.51	0.002355	152.13	5.10
1978	TO 2006	35.52	0.003601	305.49	2.23	32.74	0.002769	184.77	3.76	34.51	0.002345	152.12	5.10
1977	TO 2006	35.55	0.003591	305.22	2.23	32.74	0.002761	184.78	3.76	34.51	0.002338	152.12	5.10
1976	TO 2006	35.57	0.003581	305.00	2.23	32.74	0.002754	184.79	3.76	34.51	0.002331	152.11	5.10
1975	TO 2006	35.59	0.003571	304.83	2.23	32.74	0.002746	184.79	3.76	34.52	0.002325	152.10	5.10