



Orange and Rockland Utilities, Inc.
One Blue Hill Plaza
Pearl River NY 10965-9006
www.oru.com

November 26, 2008

VIA HAND DELIVERY

Public Service Commission
State of New York
Department of Public Service
Three Empire State Plaza
Albany, New York 12223

Dear Commissioners:

Orange and Rockland Utilities, Inc. ("Orange and Rockland" or the "Company") hereby submits for filing revisions to its Schedule for Gas Service, PSC No. 4 – Gas. The tariff leaves implementing the Company's proposal are set forth in Appendix A.

The tariff leaves are issued November 26, 2008, with an effective date of December 26, 2008. The Company's expectation is that the Commission will issue appropriate orders suspending the effective date of the leaves through October 31, 2009, so that the proposed rates become effective November 1, 2009.

Fifteen copies of the prepared written testimony and exhibits, which comprise the Company's direct case in support of this rate filing, are also submitted herewith.

Summary of Proposed Changes

By this filing, the Company proposes to increase the charges to customers under tariff rates in its Schedule for Gas Service, PSC No. 4 - Gas.

The filed leaves reflect the revenue requirement for the rate year, the twelve months ending October 31, 2010, and provide for an increase of approximately \$17.8 million. The impact on the Company's customers, however, will be \$12.5 million due to a reduction in the imputation for interruptible benefits and the expiration of a temporary surcharge in the monthly gas adjustment.¹ The Company also proposes a three-year plan to moderate the effect of this increase with a phased approach. The phased approach, which the Company believes is preferable, would increase rates by \$6.6 million (or 1.7

¹ The temporary surcharge was implemented in Case No. 05-G-1494 in order to provide that revenues at the end of rate year three are not higher than they would have been if the rate increase in that case were not phased in.

percent including gas supply costs) in November 2009, \$11.9 million (or 3.0 percent including gas supply costs) in November 2010 and by \$11.9 million (or 2.9 percent including gas supply costs) in November 2011. If the \$12.5 million one-year proposal were to take effect, the bill impact would be a 3.3% increase to firm full service gas customers and firm transportation customers (including gas supply costs). The Company's proposal provides revenues at levels consistent with the need for continued reliability, safety and security of the gas system for the Company's nearly 130,000 gas customers. In addition to addressing gas reliability, safety and security today and in the future, the Company is also seeking to reinforce its gas infrastructure to accommodate economic growth as businesses relocate to, or expand in, the service area.

Over the past decade, Orange and Rockland has added approximately 1,200 new residential, commercial or industrial gas customers per year, for an annual customer growth rate of about 1.0 percent. During that same period, Orange and Rockland has invested approximately \$155 million in capital improvements and has experienced substantial inflationary cost increases.

Orange and Rockland's service area has seen record-setting job growth – by far the highest rate of job growth performance of any of New York State's ten economic regions. The large number of businesses moving into or expanding within the area has sustained the job growth rate, which provides a robust broadening of the tax base for municipalities. Yet, the infusion of new and increased usage of the natural gas system places greater demands on the existing gas delivery infrastructure.

Orange and Rockland intends to continue to invest the resources needed for reliable, safe and secure gas delivery service in the future and to further strengthen and improve the gas system infrastructure. Chief among the initiatives proposed are those meeting load growth requirements in Orange County, which since 2000 has experienced the fastest population growth rate of any county in New York State. The capital investments will include the upgrading of two regulator stations, new mains for reliability in Orange County areas where supply is currently restricted to a one-way source, and accelerating the replacement of aging gas main. The Company proposes to expand an Orange County gas economic development enhancement pilot program, approved in the Company's last gas base rate case, which will facilitate continued economic development by allowing for the installation of gas facilities in priority growth areas. The Company also is proposing a natural gas conversion plan that will allow both residential and commercial customers to switch to gas service. In addition, Orange and Rockland will implement a secondary valve inspection program, which will compliment its existing primary valve inspection program, which should enhance the integrity of the gas system.

Orange and Rockland also proposes to implement various operational improvements to provide better service to customers. The Company is expanding the use of proven technologies like the gas computer dispatch system to realize greater precision, speed and efficiency in our work practices to serve our customers better. Gas Troubleshooters and a Gas Service Supervisor will be added to perform the secondary

valve inspection program. Gas Construction Supervisors will be added in both the Eastern and Northern Divisions in order to supplement supervision for planned capital projects. Gas fitters will allow the Company to perform main replacement work and new business installations. The addition of other personnel including a Projects Engineer, Locators, a Standards Engineer, a Gas Engineering Coordinator and a Contract Administration Planner, will enhance the Company's ability to provide safe and reliable service.

In addition, the Company proposes to implement a compressed natural gas ("CNG") pilot program whereby it will provide a financing incentive for the installation of CNG home fueling appliances. Facilitating the refueling options available will encourage the use of natural gas as an alternative transportation fuel for commuters and operators of vehicle fleets. Automobiles fueled by CNG provide demonstrable environmental benefits including reduced carbon dioxide, carbon monoxide and nitrogen-oxide emissions.

In addition, the Company is amenable to increasing the amount of the bill credit for low-income customers, so as to keep pace with the required rate increase, and will confer with interested parties regarding the appropriate amount of such an increase.

Over the past few years, the financial position of many companies in the energy industry has deteriorated sharply. Financial weakness reduces the ability to attract, at reasonable terms, capital needed to make long-term investments in infrastructure.

Maintenance of financial integrity is vital to a critical infrastructure company like Orange and Rockland, particularly given the ongoing financial crisis that seems likely to continue through the rate year. Following a downgrade earlier this year, Orange and Rockland has an "A" credit rating, although its cash flow measures are weak for that rating. In a report on Orange and Rockland published on March 21, 2008, Moody's specifically notes in its rating rationale (placing the Company on Negative Outlook) that, "Some of O&R's historical credit metrics have been somewhat weaker than what we typically expect to see from "A" rated entities in this sector." This rate proposal is directed to Orange and Rockland's financial strength, to give the Company the ability to make the investments needed to meet its customers' needs. It is imperative that the Commission approve this rate proposal so as to preserve the Company's "A" rating and therefore ensure Orange and Rockland's continued access to capital on reasonable terms.

The Company's presentation provides appropriate evidence that gas rates need to be above existing levels if reliable, safe and secure gas service is to be maintained and improved, increases in gas load are to be served, and the Company's gas operations are to be financially viable.

The tariffs and data submitted herewith are predicated on providing the Company a reasonable opportunity to earn a return of 11 percent on common equity capital. This level, which is lower than the level provided utilities in most other jurisdictions, is critical

to maintaining the Company's financial security. We respectfully believe that increased allowed levels for earnings are indicated.

Appendix B shows the estimated effect on customers' bills and Company revenues resulting from the proposed increase, based on sales and revenues for the rate year, the twelve months ending October 31, 2010. The testimony also includes provisions for a multi-year rate plan that addresses incremental revenue requirements for an additional two-year period.

The Proposed Increased Revenue Allocation

The revenue increase was allocated to the Company's SC Nos. 1, 2 and 6 customers in the following three-step process:

- First the Company proposes to realign rate year base rate revenues at the current rate level for SC No. 1 (which for revenue allocation purposes includes SC No. 6 Rate Schedule IA) and SC No. 2 (which for revenue allocation purposes includes SC No. 6 Rate Schedules IB and II) to address the deficiency and surplus indications from the embedded cost of service ("ECOS") study. Since fully eliminating the deficiency and surplus, coupled with the delivery revenue increase, would result in a very large revenue impact for SC No. 1 as compared with SC No. 2, the Company is proposing to eliminate one-third of the deficiency and surplus. This will move the classes in the direction of more closely matching costs and revenues while limiting the customer bill impacts associated with the changes. In the event the multi-year rate plan proposed by the Company is adopted, the Company intends to further reduce any deficiency and surplus in the additional rate years.
- Second, based on the increased level of proposed delivery revenue, revised revenue levels were determined for the merchant function charge ("MFC") fixed components. The changes in MFC fixed component revenue were then subtracted from the delivery revenue requirement for each class to determine the non-competitive delivery revenue requirement for each class.
- Third, based on delivery volumes during a historic period, the class-specific incremental non-competitive delivery revenue increases were allocated between first block charges (charges for the first 3 Ccf in Service Classification Nos. 1 and 2 and Service Classification No. 6, Rate Schedule IA and IB and the charge for the first 100 Ccf in Service Classification No. 6 Rate Schedule II) and per Ccf charges. The Company proposes to increase the first block charges for SC Nos. 1 and 2 and SC No. 6 Rate Schedules IA and IB by 1.5 times the overall delivery revenue increase percentage. The Company also proposes to increase the first block charge for SC No. 6 Rate Schedule II customers by the proposed percentage increase in overall delivery revenues. These increases more closely match the first block charges with their

corresponding costs of service while limiting the rate impacts of the changes. Within each class, the remaining incremental revenue increase, after adjusting for increases in the first block charges, was applied to the per Ccf charges on an equal percentage basis.

The proposed revenue increase allocation is supported by the enclosed gas ECOS study (Exhibit G-14 in the Company's pre-filed case).

Base Rate Revenue Imputation

Currently the Company has a revenue imputation of \$4.6165 million for non-firm revenues. In the currently-effective rate plan, established by the Commission in Case No. 05-G-1494, the Commission authorized the Company to retain the first \$4.6165 million of net benefits from the sale and transportation of gas to interruptible customers and net benefits from the transfer of gas to electric generating facilities previously owned by the Company. Eighty percent of net interruptible profits and 100% of profits from the transportation of gas for generation above or below the imputation were passed back or surcharged to both retail access and full service customers through the Monthly Gas Adjustment. The Company is proposing to lower the level of interruptible sales included in the target in order to eliminate a non-recurring adjustment made in Case 05-G-1494 and to reflect the current level of profits from those sales.

Interruptible Transportation Service

The Company is also proposing changes with regard to its interruptible transportation service. Specifically, the Company is proposing to:

- Allow the cap on the Base Charge, used to determine the blocked rates for SC No. 8, interruptible transportation service, to expire effective November 1, 2009; and
- Close SC No. 8 to new customers effective November 1, 2009.

Other Tariff Changes

The Company is proposing the following additional tariff changes:

- Transfer recovery of credit and collections-related costs from the merchant function charge applicable to customers whose marketers participate in the purchase of receivables ("POR") program to the POR discount applicable to marketers;
- Changes to the transition adjustment for competitive services to address the transfer of credit and collections-related costs;
- A change in the allocation of gas in storage working capital costs between full service and retail access customers;

- A limit on the incentive/penalty for lost and unaccounted for gas;
- Elimination of the deadband and an update of the definition of normal heating degree days in the weather normalization mechanism; and
- Elimination of the roll over option for settling marketers' monthly imbalance volumes under Service Classification No. 11.

The Need for Gas Rate Relief

The Company's evidence documents the need for rate relief. Rate increases are rarely, if ever, a sought-after or otherwise welcome development. Orange and Rockland has worked hard to balance the objective of keeping rates as low as practicable with the need to supply safe and reliable service and to maintain a strong energy infrastructure capable of supporting continued economic growth. Granting the requested rate relief will allow the Company an opportunity to achieve these important objectives and maintain financial integrity. The Company would note that it currently is earning below its allowed rate of return for gas operations.

Several significant cost drivers have contributed to the need to seek rate relief. Actual and forecast gas sales to firm customers are 2,100 MMcf's lower on an annual basis than the level embedded in rates. When combined with lower interruptible transportation volumes, the lower sales are causing a revenue shortfall of \$5.3 million. Increases in operating costs for wages, related employee benefits account for \$3 million of the rate request. New and expanded maintenance and environmental programs represent \$1.7 million. Depreciation and the carrying cost of new investment represent \$2.5 million of the increase. Higher property and other taxes amount to \$1 million and the higher cost of financing due to current economic conditions contributes \$5.3 million. Partially offsetting these increases are \$1 million of savings related to proposed depreciation rate changes, along with tax law changes and additional deductions that will result in a lower effective corporate income tax rates.

The Company recognizes the extreme volatility in the cost of gas commodity. Working with public officials, the Company is taking appropriate steps to communicate and deal with consumers affected by these sharp fluctuations. These steps include hedging of gas supply to reduce gas price volatility, facilitation of supply competition via third-party supply and extensive customer outreach. The Company does not expect the proposals set forth in this filing to take effect prior to November 2009, and, with reference to the winter of 2008-2009, the Company and other stakeholders will continue efforts to monitor and mitigate impacts of commodity price volatility.

The Company will discuss the parameters of its rate proposal with Commission Staff and other parties to the rate proceeding. The Company looks forward to obtaining the input of all stakeholders in formulating a comprehensive gas rate plan that reflects the numerous interests at stake.

Also included with this filing is a proposed form of Notice of Proposed Rulemaking for publication in the State Register pursuant to the State Administrative Procedure Act. Notice of this filing will be published in accordance with 16 NYCRR 720-8.1 and proof of publication will be submitted upon completion. In addition, the Company will issue appropriate bill inserts in accordance with 16 NYCRR 720-9.1.

Conclusion

The testimony and exhibits submitted herewith establish the need for the rate relief requested by the Company. The Company will pursue discussions with the Commission Staff and other parties to the proceeding in an effort to reach agreement on the issues presented. The Company respectfully requests that, in the absence of agreement of the parties, the Commission allow the proposed rate leaves to become effective not later than November 1, 2009, thereby providing the rate relief consistent with the Company's submission herein.

Very truly yours,

ORANGE AND ROCKLAND UTILITIES,
INC.

By



Robert N. Hoglund
Chief Financial Officer and
Controller

Enclosure

c: New York State Consumer
Protection Board (2 sets)

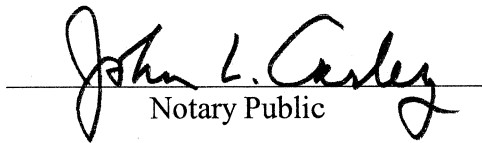
STATE OF NEW YORK
COUNTY OF NEW YORK

Robert N. Hoglund, being duly sworn, says:

I am the Chief Financial Officer and Controller of ORANGE AND ROCKLAND UTILITIES, INC., the applicant above-named, on behalf of which I have subscribed the foregoing application and know the contents thereof and the same is true to the best of my knowledge, information and belief.

A handwritten signature in cursive script, reading "Robert Hoglund", written over a horizontal line.

Subscribed and sworn to
Before me this 26th day of November 2008

A handwritten signature in cursive script, reading "John L. Carley", written over a horizontal line.
Notary Public

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

Orange and Rockland Utilities, Inc.
Gas Rate Case
Proposed Tariff Leaves effective December 26, 2008

P.S.C. No. 4 Gas

Leaf 4	Revision 9	Leaf 94.16	Revision 7
Leaf 33.3	Revision 7	Leaf 113	Revision 4
Leaf 33.4	Revision 1	Leaf 113.1	Revision 0
Leaf 76	Revision 6	Leaf 113.2	Revision 0
Leaf 79.1	Revision 2	Leaf 114	Revision 17
Leaf 79.2	Revision 2	Leaf 115	Revision 11
Leaf 80	Revision 11	Leaf 116	Revision 19
Leaf 80.1	Revision 13	Leaf 117	Revision 9
Leaf 80.2	Revision 9	Leaf 130	Revision 18
Leaf 80.3	Revision 12	Leaf 130.1	Revision 2
Leaf 80.3.1	Revision 1	Leaf 131	Revision 9
Leaf 80.4	Revision 3	Leaf 132	Revision 9
Leaf 81	Revision 8	Leaf 133	Revision 20
Leaf 81.1	Revision 6	Leaf 137	Revision 8
Leaf 82	Revision 8	Leaf 137.2	Revision 6
Leaf 94.9	Revision 4	Leaf 152.3	Revision 3
Leaf 94.10	Revision 4	Leaf 153	Revision 10
Leaf 94.11	Revision 6	Leaf 154.1	Revision 4

Orange and Rockland Utilities, Inc.

Impact of Proposed Rate Change on Total Revenue
For the Rate Year Twelve Months Ending October 31, 2010
(Based on Billed Sales and Revenues)

S.C. No.	Type of Service	Total Sales (Mcf)	Customers	Total Revenue at:		Increase:	
				Present Rates (000's)	Proposed Rates (000's)	Amount (000's)	Percent
<u>Sales to the Public:</u>							
1	Residential	7,593,454	69,488	151,056.1	157,360.2	\$6,304.1	4.2%
1/2	Commercial	<u>1,852,019</u>	<u>6,016</u>	<u>34,214.7</u>	<u>34,667.5</u>	<u>452.8</u>	1.3%
	Total Firm Sales	9,445,473	75,504	185,270.8	192,027.7	6,756.9	3.6%
6	Firm Trans.*	<u>10,264,400</u>	<u>51,124</u>	<u>192,503.4</u>	<u>198,203.3</u>	<u>5,699.9</u>	3.0%
	Total Firm	19,709,873	126,628	377,774.2	390,230.9	12,456.8	3.3%
3	Interruptible	0	1	0.0	0.0	0.0	0.0%
5	Firm Dual Fuel	1,900	2	24.0	24.0	0.0	0.0%
7	NGV	0	0	0.0	0.0	0.0	0.0%
8	Interruptible Trans	2,842,500	46	2,229.0	2,229.0	0.0	0.0%
9	Withdrawable Trans	0	0	0.0	0.0	0.0	0.0%
10	Withdrawable Sales	<u>2,477,800</u>	<u>0</u>	<u>6,581.7</u>	<u>6,581.7</u>	<u>0.0</u>	0.0%
Total Sales to the Public		<u>25,032,073</u>	<u>126,677</u>	<u>386,608.9</u>	<u>399,065.6</u>	<u>12,456.8</u>	3.2%
Sales for Resale		0	0	2,048.0	2,048.0	0.0	0.0%
Other Operating Revenue		<u>0</u>	<u>0</u>	<u>2,259.0</u>	<u>2,259.0</u>	<u>0.0</u>	0.0%
Total		<u>25,032,073</u>	<u>126,677</u>	<u>390,915.9</u>	<u>403,372.6</u>	<u>12,456.8</u>	3.2%

* For comparison purposes, a cost of gas supply has been included in the SC No. 6 revenue. This is equivalent, on a per unit basis, to the cost of gas supply included in SC No. 1 and 2 revenues at proposed rates. With the cost of gas excluded from SC No. 6 revenue, the percentage increase is 12.5%

NYS DEPARTMENT OF STATE

Notice of Proposed Rule Making

Public Service Commission
(SUBMITTING AGENCY)

**NOTE: Typing and submission instructions are at the end of this form. Please be sure to COMPLETE ALL ITEMS.
Incomplete forms and nonscannable text attachments will be cause for rejection of this notice.**

Pursuant to the provisions of the State Administrative Procedure Act (SAPA), NOTICE is hereby given of the following agency action:

1. Proposed action:

The Public Service Commission (the "PSC") is considering whether to approve, reject, in whole or in part, or modify a proposal filed by Orange and Rockland Utilities, Inc. (the "Company") to make various changes in the charges, rules, and regulations contained in its gas tariff schedule, P.S.C. No. 4 - Gas, effective December 26, 2008.

2. Statutory authority under which rule is proposed:

Public Service Law, Section 66(12).

3. Subject of rule:

Tariff leaves reflecting increases in the rates and charges contained in Orange and Rockland's Schedule for Gas Service, P.S.C. No. 4 - Gas.

4. Purpose of rule:

Consideration of tariff changes reflecting a revenue requirement for the rate year, the twelve months ending October 31, 2010, of approximately \$17.8 million. The impact on the Company's customers, however, will be \$12.5 million due to a reduction in the imputation for interruptible benefits and the expiration of a temporary surcharge in the monthly gas adjustment. This represents a 3.3% increase to firm full service gas customers and firm transportation customers (including gas supply costs).

5. Terms of rule (check applicable box):

☐ The rule contains 2,000 words or less. An original copy of the text in scannable format is attached to this form.

☐ The rule contains more than 2,000 words. Therefore, an original copy of a summary the text (in scannable format) is attached to this form.

☐ Pursuant to SAPA § 202(7)(b), the agency elects to print a description of the subject, purpose and substance of the rule containing less than 2,000 words. The original text in scannable format is attached to this form.

6. The text of the rule and any required statements or analyses may be obtained from:

Name of agency contact Margaret Maguire, Clerk II

Office address Three Empire State Plaza

Albany, New York 12223

Telephone number (518) 474-3204

7. Regulatory Impact Statement (RIS) (check applicable box):

- ☐ A RIS of 2,000 words or less is submitted with this notice.
- ☐ A summary of the RIS is submitted with this notice because the full text exceeds 2,000 words.
- ☐ A consolidated RIS is submitted with this notice because:
- ☐ the rule is one of a series of closely related and simultaneously proposed rules.
- ☐ the rule is one of a series of virtually identical rules proposed during the same year.
- ☐ An RIS is not submitted because this rule is a technical amendment and, therefore, exempt from SAPA § 202-a. Attached to this notice is a statement of the reason(s) for claiming this exemption.
- ☐ An RIS is not submitted because this rule is subject to a consolidated RIS printed in the Register under a notice of proposed rule making ID No. PSC-_____; Register date: _____.
- ☒ An RIS is not submitted with this notice because this rule is a "rate making" as defined in SAPA § 102(2)(a)(ii).

8. Regulatory Flexibility Analysis for Small Businesses (RFASB) (check applicable box):

- ☐ An RFASB of 2,000 words or less is submitted with this notice.
- ☐ A summary RFASB is submitted with this notice because the full text exceed 2,000 words.
- ☐ A consolidated RFASB is submitted with this notice because this rule is the first of a series of closely related rules that will be the subject of the same analysis.
- ☐ An RFASB is not submitted because this rule will not impose any adverse economic impact or reporting, recordkeeping or other compliance requirements on small businesses. A statement is attached setting forth this agency's finding and the reasons upon which the finding was made, including what measures were used by this agency to ascertain that this rule will not impose such adverse economic impact or compliance requirements on small businesses.
- ☐ An RFASB is not submitted because this rule is subject to a consolidated RFASB printed in the Register under a notice of proposed rule making, ID No. _____; Register date: _____.
- ☒ An RFASB is not submitted with this notice because this rule is a "rate making" as defined in SAPA § 102(2)(a)(ii).

9. Rural Area Flexibility Analysis (RAFA) (check applicable box):

- ☐ An RAFA of 2,000 words or less is submitted with this notice.
- ☐ A summary RAFA is submitted with this notice because the full text exceeds 2,000 words.
- ☐ A consolidated RAFA is submitted with this notice because this rule is the first of a series of closely related rules that will be the subject to the same analysis.
- ☐ An RAFA is not submitted because this rule will not impose any adverse impact or reporting, recordkeeping or other compliance requirements on public or private entities in rural areas. A statement is attached setting forth this agency's finding and the reasons upon which the finding was made, including what measures were used by this agency to ascertain that this rule will not impose such adverse impact or compliance requirements on rural areas.
- ☐ An RAFA is not submitted because this rule is subject to a consolidated RAFA printed in the Register under a notice of proposed rule making, ID No. _____; Register date: _____.
- ☒ An RAFA is not submitted because this rule is a "rate making" as defined in SAPA § 102(2)(a)(ii).

10. Job Impact Statement (JIS) (check applicable box):

- ☐ A JIS of 2,000 words or less is submitted with this notice.
- ☐ A summary JIS is submitted with this notice because the full text exceeds 2,000 words.
- ☐ A JIS/Request for Assistance is submitted with this notice.
- ☐ A consolidated JIS is submitted with this notice because this rule is the first of a series of closely related rules that will be subject to the same analysis.
- ☐ A JIS is not submitted because it is apparent from the nature and purpose of the rule that it will not have a substantial adverse impact on jobs and employment opportunities. A statement is attached setting forth this agency's finding that the rule will have a positive impact or no impact on jobs and employment opportunities; except when it is evident from the subject matter of the rule that it could only have a positive impact or no impact on jobs and employment opportunities, the statement shall include a summary of the information and methodology underlying that determination.
- ☐ A JIS is not submitted because this rule is subject to a consolidated JIS printed in the **Register** in a notice of proposed rule making ID No. _____; Register date: _____.
- ☒ A JIS is not submitted with this notice because this rule is a "rate making" as defined in SAPA § 102(2)(a)(ii).
- ☐ A JIS is not submitted because this rule is proposed by the State Comptroller or Attorney General.

11. Prior emergency rule making for this action was previously published in the _____ issue of the Register, I.D. No. _____.

12. Expiration Date (check only if applicable):

[X] This proposal will not expire in 180 days because it is for a "rate making" as defined in SAPA § 102(2)(a)(ii).

13. Public Hearings (check box and complete as applicable)

[] A public hearing is required by law and will be held at ___ a.m./p.m. on _____, 19__, at

[] A public hearing is not required by law, and has not been scheduled.

[] A public hearing is not required by law, but will be held at ___ a.m./p.m. on _____, 19 __, at

14. Interpreter Service (check only if a public hearing is scheduled):

[] Interpreter services will be made available to hearing impaired persons, at no charge, upon written request submitted within a reasonable time prior to the scheduled hearing. Requests must be addressed to the agency contact designated in this notice.

15. Accessibility (check appropriate box only if a public hearing is scheduled):

[] All public hearings have been scheduled at places reasonably accessible to persons with a mobility impairment.

[] All public hearings except the following have been scheduled at places reasonably accessible to persons with a mobility impairment:

1. _____
2. _____
3. _____

[] None of the scheduled public hearings are at places that are reasonably accessible to persons with a mobility impairment.

[] An **optional** explanation is being submitted regarding the nonaccessibility of one or more hearing sites.

16. Submit data, views or arguments to (complete only if different than previously named agency contact):

Name of agency contact Jaclyn A. Brilling, Secretary
Office address Three Empire State Plaza
Albany, New York 12223
Telephone number (518) 474-6530

17. Additional matter required by statute:

☒ Check box if NOT applicable.

18. Public comment will be received until:

☒ 45 days after publication of this notice (MINIMUM, public comment period).

☐ 5 days after the last scheduled public hearing required by statute (MINIMUM, with required hearing).

☐ Other: (specify) _____.

19. Regulatory Agenda: (**The Division of Housing and Community Renewal; Workers Compensation Board; and the departments of Agriculture and Markets, Banking, Education, Environmental Conservation, Health, Insurance, Labor and Social Services** and any other department specified by the governor or his designee must complete this item. If your agency had an optional agenda published, that should also be indicated below):

☐ This action was listed as a Regulatory Agenda item in the first January issue of the Register, 19__.

☐ This action was listed as a Regulatory Agenda item in the last June issue of the Register, 19__.

☐ This action was not under consideration at the time this agency's Regulatory Agenda was submitted for publication in the Register.

AGENCY CERTIFICATION (To be completed by the person who PREPARED the notice)

I have reviewed this form and the information submitted with it. The information contained in this notice is correct to the best of my knowledge.

I have reviewed Article 2 of SAPA and Parts 260 through 263 of 19 NYCRR, and I hereby certify that this notice complies with all applicable provisions.

Name _____ Signature _____
Address _____
Date _____ Telephone _____

Please read before submitting this notice:

1. Except for this form itself, all text must be typed in scannable format as described in the Department of State's "NYS Register Procedures Manual."
2. Submit the **original notice and scanner copy** collated as (1) form; (2) text or summary of rule; and if any, (3) regulatory impact statement, (4) regulatory flexibility analysis for small businesses, (5) rural area flexibility analysis, (6) job impact statement - **and ONE copy of that set.**
3. **Hand deliver to:** DOS Office of Information Services, 41 State Street (3rd Floor), Albany
Address mail to: Register/NYCRR unit, Department of State, Albany, NY 12231

TABLE OF CONTENTS

GENERAL INFORMATION	<u>Leaf No.</u>
13. Form of Application for Service	
13.1 General	84
14. Customer Complaints	
14.1 Billing Disputes	91
14.2 Publicizing Complaint Procedures	91
15. Increase in Rates and Charges Applicable in Municipality Where Service Is Supplied	92
16. Service Classification Riders	
Rider A - Gas Transportation Service Program	94
Rider B - Gas Rates for Commercial and Industrial Distributed Generation Facilities	94.7
Rider C - Gas Rates for Residential Distributed Generation Facilities	94.15
17. Minimum Insulation Standards for New Dwellings	
17.1 Definitions	95
17.2 Applicability and Compliance	95
17.3 Waivers	96
17.4 Certificate of Compliance	96
17.5 Compliance Procedures	96
17.6 Penalties for Non-Compliance	97
18. Minimum Insulation Standards for Existing Dwellings Converting to Gas Space Heat	
18.1 Definitions	98
18.2 Applicability and Conditions	98
18.3 Waivers	98
18.4 Certificate of Compliance	99
18.5 Penalties for Non-Compliance	100
19. Form for Certificate of Compliance	
19.1 Certificate of Compliance for New Residential Construction	101
19.2 Conversion to Gas Space Heat by Owner	102
19.3 Conversion to Gas Space Heat by Contractor or Company Representative	103
20. Non-Residential Customer Payment Agreement	104
21. Deposit Waiver Form	106
22. Residential Customer Payment Agreement	108
23. Systems Benefits Charge	112
24. Revenue Decoupling Mechanism ("RDM") Adjustment	113

GENERAL INFORMATION

6. METERING AND BILLING (Cont'd.)

6.5 RENDERING OF BILLS (Cont'd.)

(2) Transportation Customer Billing Options (Cont'd.)

(B) Utility Single Billing Service

A Marketer requesting that its charges be included on a Utility Single Bill must execute the Company's Consolidated Billing and Assignment Agreement.

Under Utility Single Billing Service, the Company shall purchase the Marketer's receivables. That is, the Marketer assigns to the Company its rights in all amounts due from all of its customers participating in the Company's Retail Access Program and receiving a Utility Single Bill. By the 20th of each month (or the next business day if the 20th falls on a Saturday, Sunday, or public holiday), the Company shall remit to the Marketer all undisputed Marketer charges billed to its customers in the previous calendar month, reduced by the Purchase of Receivables ("POR") Discount Percentage as described below.

The POR Discount Percentage shall consist of an Uncollectibles Percentage, Credit and Collections Costs and a Risk Factor. The Uncollectibles Percentage shall be set annually, effective each November 1, based on the Company's actual uncollectibles experience applicable to all gas and electric POR-eligible customers for the twelve month period ended the previous June 30. The Credit and Collections Component will be determined by dividing the Company's credit and collection expenses attributable to retail access customers whose Marketers participate in the Company's POR program by the estimated gas supply costs to be billed on the Marketer's behalf. The percentage for credit and collections to be included in the POR Discount Percentage will be determined annually based on the forecast of commodity costs to be billed on behalf of Marketers through the POR program. The Risk Factor shall also be reset annually and shall be equal to 20 percent of the Uncollectibles Percentage. The POR Discount Percentage for the twelve month period commencing November 1, 2009 is 0.729 percent. The POR Discount Percentage shall be reset each November 1.

The Company will collect and process customers' payments and perform collection activities in accordance with the Home Energy Fair Practices Act.

PSC NO. 4 GAS
ORANGE AND ROCKLAND UTILITIES, INC.
INITIAL EFFECTIVE DATE: December 26 , 2008

LEAF: 33.4
REVISION: 1
SUPERSEDING REVISION:

GENERAL INFORMATION

6. METERING AND BILLING (Cont'd.)

6.5 RENDERING OF BILLS (Cont'd.)

(2) Transportation Customer Billing Options (Cont'd.)

(B) Utility Single Billing Service (Cont'd.)

To be effective for the next bill issued to the customer, at least 15 calendar days prior to the first of the calendar month in which service is to be rendered, the Marketer will provide the Company a rate per Ccf (\$/Ccf) to be charged each of its customers for gas supply. Rates must include any applicable gross receipts taxes or other taxes imposed on the Marketer and not required by law to be separately stated. The Company will calculate and identify the sales and use taxes associated with Marketer charges in accordance with customer-specific tax status information provided by the Marketer and remit such amounts to the Marketer net of the POR discount and such other amounts as set forth in the Company's Consolidated Billing and Assignment Agreement. The Marketer may charge a different price per Ccf for each of its customers. The customer shall be billed one rate per billing cycle and such rate will be used for billing purposes for the

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GENERAL INFORMATION

12. ADJUSTMENT OF RATES IN ACCORDANCE WITH CHANGES IN THE COST OF GAS
(Cont'd.)

12.1 GAS SUPPLY CHARGE (Cont'd.)

(D) Annual Reconciliation (Cont'd.)

(1) (Cont'd.)

and Balancing and Peak Shaving Supply Fees assessed under Service Classification No. 6 as recorded on the Company's books during the determination period, adjusting that cost to reflect a level of purchased gas commensurate with actual sales and the fixed factor of adjustment, and subtracting therefrom an amount equal to:

- (a) Gas Supply Charge revenues recorded during the determination period, adjusted to eliminate associated revenue tax recoveries;
- (b) costs recorded during the determination period assignable to gas sold to customers not subject to the Gas Supply Charge; and
- (c)
 - (i) the previous year's over-collection including interest, to the extent not refunded, or
 - (ii) adding the previous year's under-collection including interest, to the extent not recovered.
- (2) The amount derived in paragraph (1) of this subdivision shall be divided by the quantities of gas to be sold by the Company to its customers during the surcharge/refund period.
- (3) Surcharge or refund amounts shall bear interest, at a rate prescribed by the Commission, on unamortized balances.
- (4) The determination period to be used in the computation of the surcharge or refund shall be the 12 months ended August 31 of each year. The computation shall be filed with the Commission on or before October 15, and the resulting surcharge or refund shall be effective with the first January billing cycle date.
- (5) Revisions to the annual surcharge/refund adjustment will be permitted during the 12 month period ended August 31 for the purpose of preventing large over-collection or under-collection balances from accruing at August 31, subject to Commission approval.

PSC NO. 4 GAS
ORANGE AND ROCKLAND UTILITIES, INC.
INITIAL EFFECTIVE DATE: December 26, 2008

LEAF: 79.1
REVISION: 2
SUPERSEDING REVISION: 1

GENERAL INFORMATION

12. ADJUSTMENT OF RATES IN ACCORDANCE WITH CHANGES IN THE COST OF GAS (Cont'd.)

12.2 MONTHLY GAS ADJUSTMENT

(B) Transition Adjustment for Competitive Services

(1) Applicability

A Transition Adjustment for Competitive Services ("TACS") is applicable to customers taking service under Service Classification Nos. 1, 2, and 6 of this Rate Schedule. Such customers will be assessed the TACS on a per Ccf basis as set forth in the Statement of Monthly Gas Adjustment. The TACS shall be reset annually effective November 1 of each year.

(2) Definitions for Purposes of the TACS

"Merchant Function Charge Fixed Component Lost Revenue" shall be equal to a target of \$1,545,050 attributable to the Merchant Function Charge ("MFC") Fixed Components consisting of a) commodity procurement costs (including commodity revenue based allocation of information resources and education and outreach costs); and b) credit and collections costs portions of the MFC, minus the revenues received through the MFC relating to such MFC Fixed Components.

"Billing and Payment Processing Lost Revenue" shall be equal to the total of billing and payment processing charges avoided by retail access customers less billing service charges assessed on Marketers participating in the Company's Gas Transportation Service program and electing the Utility Single Bill Option, less the Company's avoided costs associated with Marketers participating in the Company's Gas Transportation Service Program and electing the Marketer Single Bill Option.

"Credit and Collections Lost Revenue Associated with Retail Access" shall be equal to a target of \$465,113 attributable to credit and collections costs reflected in the POR discount minus revenues received through the credits and collections component of the POR discount.

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GENERAL INFORMATION

12. ADJUSTMENT OF RATES IN ACCORDANCE WITH CHANGES IN THE COST OF GAS
(Cont'd.)

12.2 MONTHLY GAS ADJUSTMENT (Cont'd.)

(B) Transition Adjustment for Competitive Services (Cont'd.)

(2) Definitions for Purposes of the TACS (Cont'd.)

"Prior Period Reconciliation" represents the difference between the amount to be recovered through the TACS and the actual amount recovered through the TACS. Any under-recovery or over-recovery resulting from such reconciliation, plus interest (calculated at the Other Customer Capital Rate), shall be included in the calculation of the subsequent year's TACS.

(3) Calculation of the TACS

The TACS shall be determined by dividing the sum of the MFC Fixed Component Lost Revenue, Billing and Payment Processing Lost Revenue, Credit and Collections Lost Revenue Associated with Retail Access, and the Prior Period Reconciliation by the forecasted Ccf deliveries to Service Classification Nos. 1, 2, and 6 customers for the twelve-month period for which the TACS is to be effective.

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GENERAL INFORMATION

12. ADJUSTMENT OF RATES IN ACCORDANCE WITH CHANGES IN THE COST OF GAS
(Cont'd.)

12.2 MONTHLY GAS ADJUSTMENT (Cont'd.)

(C) Credit/Surcharge for Sharing of Benefits (applicable to Service Classification Nos. 1, 2 and 6)

The Monthly Gas Adjustment applicable to Service Classification ("S.C.") Nos. 1, 2, and 6 shall be adjusted to reflect the net benefits from 1) interruptible (S.C. Nos. 3 and 8) sales and transportation, firm withdrawable transportation and sales (S.C. Nos. 9 and 10), and firm dual fuel (S.C. No. 5) service (collectively "Interruptible Benefits") and 2) transfer of gas to electric generating facilities previously owned by the Company ("Power Generation Benefits"). Such benefits shall be determined as follows:

(1) Interruptible Benefits

Interruptible Benefits shall be defined as (1) total interruptible revenues from S.C. Nos. 3 and 8 minus any associated gas costs and revenue tax surcharge revenues; (2) total firm withdrawable delivery revenues from S.C. No. 9 and S.C. 10 minus any associated gas costs and revenue tax surcharge revenues; and (3) total firm dual fuel revenues from S.C. No. 5 minus gas costs and revenue tax surcharge revenues.

For each twelve-month period ending October 31, with the first twelve-month period ending October 31, 2010, a base rate revenue imputation of \$2,600,000 relating to the Interruptible Benefits described above shall be in effect. Any variance between the actual total Interruptible Benefits and the base rate revenue imputation for each twelve-month period shall be shared 80 percent/20 percent between customers and the Company respectively.

Customers' share of the Interruptible Benefits so determined shall be credited (or surcharged if negative) to S.C. Nos. 1, 2, and 6 customers. The rate of credit (or surcharge) shall be determined by dividing the estimated customer share available to S.C. Nos. 1, 2, and 6 customers for the twelve-month period ending October 31 of each year by the S.C. Nos. 1, 2, and 6 deliveries estimated for that period.

The Company's share of Interruptible Benefits, if any, shall be retained by the Company and shall be excluded from any determination of Company earnings in excess of the level allowed by the Public Service Commission as any of the

PSC NO. 4 GAS
ORANGE AND ROCKLAND UTILITIES, INC.
INITIAL EFFECTIVE DATE: December 26, 2008

LEAF: 80.1
REVISION: 13
SUPERSEDING REVISION: 12

GENERAL INFORMATION

12. ADJUSTMENT OF RATES IN ACCORDANCE WITH CHANGES IN THE COST OF GAS
(Cont'd.)

12.2 MONTHLY GAS ADJUSTMENT (Cont'd.)

(C) Credit/Surcharge for Sharing of Benefits (applicable to Service Classification Nos. 1, 2 and 6) (Cont'd.)

provisions of Section 66, subsection 20 of the Public Service Law of the State of New York.

(2) Power Generation Benefits

Power Generation Benefits from the transfer of gas to electric generating facilities previously owned by the Company shall be defined as the amount received for the transfer of gas to such facilities, less any associated gas costs.

For each twelve-month period ending October 31, with the first twelve-month period ending October 31, 2010, a power generation base rate revenue imputation of \$650,000 shall be in effect. Any variance between the actual total Power Generation Benefits and the power generation base rate revenue imputation for each twelve-month period shall be credited (or surcharged if negative) to S.C. Nos. 1, 2, and 6 customers. The rate of credit (or surcharge) shall be determined by dividing the estimated power generation benefits available to S.C. Nos. 1, 2, and 6 customers for the twelve-month period ending October 31 of each year by the S.C. Nos. 1, 2, and 6 deliveries estimated for that period.

The unit rates as determined in (1) and (2) above will be applied to the Monthly Gas Adjustment. At the end of the fiscal year, the Company will determine the actual benefits accrued and compare this amount to the benefits disbursed to (or recovered from) S.C. Nos. 1, 2, and 6 customers during the fiscal year.

Any difference between the benefits accrued and the benefits disbursed (or recovered) shall be reflected in the estimated credits (or surcharges) for the next fiscal year.

The Company shall modify the unit rates determined as described above if a significant change to its estimates of benefits and/or sales volumes occurs during a fiscal year.

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GENERAL INFORMATION

12. ADJUSTMENT OF RATES IN ACCORDANCE WITH CHANGES IN THE COST OF GAS
(Cont'd.)

12.2 MONTHLY GAS ADJUSTMENT (Cont'd.)

(D) Gas in Storage Working Capital (applicable to Service Classification Nos. 1, 2 and 6)

The Monthly Gas Adjustment shall be adjusted by a per Ccf rate to reflect gas in storage working capital costs associated with storage assets used for reliability and balancing purposes. Such rate shall be equal to 50 percent of the total gas in storage working capital rate applicable to firm sales customers. Such rate shall be applied to (1) sales to Service Classification Nos. 1 and 2 customers and (2) deliveries to Service Classification No. 6 customers. The difference between the rate included in the Monthly Gas Adjustment and the total gas in storage working capital rate applicable to firm sales customers shall be deemed to be sales related and shall be included in the Merchant Function Charge applicable to Service Classification No. 1 and Service Classification No. 2 customers. Gas in storage working capital costs recovered through the Monthly Gas Adjustment and the Merchant Function Charge shall be combined and trued up annually to actual costs determined by multiplying the actual twelve-month average gas in storage balance by the Company's pre-tax weighted average cost of capital. This true up will be part of an annual reconciliation of the Monthly Gas Adjustment.

(E) Research and Development Surcharge (applicable to Service Classification Nos. 1, 2 and 6)

Customers will be assessed a Research and Development ("R&D") Surcharge to provide funding for gas R&D projects in accordance with the Commission's February 14, 2000 Order in Case No. 99-G-1369.

(F) Capacity Release Service Adjustment (applicable to Service Classification No. 6)

The Monthly Gas Adjustment applicable to all Service Classification No. 6 customers shall be adjusted to reflect a Capacity Release Service Adjustment. The Capacity Release Service Adjustment is a charge/credit reflecting the difference between the maximum firm reservation rates at which the capacity is released to Sellers taking service under Service Classification No. 11 and the Company's Adjusted WACOT.

PSC NO. 4 GAS LEAF: 80.3
ORANGE AND ROCKLAND UTILITIES, INC. REVISION: 12
INITIAL EFFECTIVE DATE: December 26, 2008 SUPERSEDING REVISION: 11

GENERAL INFORMATION

12. ADJUSTMENT OF RATES IN ACCORDANCE WITH CHANGES IN THE COST OF GAS (Cont'd.)

12.2 MONTHLY GAS ADJUSTMENT (Cont'd.)

(F) Capacity Release Service Adjustment (applicable to Service Classification No. 6) (Cont'd.)

The Capacity Release Service Adjustment shall be set annually based on the Company's estimate of its Adjusted WACOT for the applicable annual period, the current interstate pipeline reservation rates for the pipelines upon which the Company releases capacity, and estimated deliveries to Service Classification No. 6 customers.

Any difference between the amount charged/credited to Service Classification No. 6 customers through the Capacity Release Service Adjustment and the actual differences between pipeline reservation rates and the Company's Adjusted WACOT shall be reconciled annually and reflected in either the Capacity Release Service Adjustment or another adjustment to the Monthly Gas Adjustment billed in the second month following the annual period. The Company may apply such adjustment over a period greater than one month, if deemed necessary by the Company, to mitigate the customer bill impact of the adjustment.

(G) Curtailement Cost Recovery Charge (applicable to Service Classification Nos. 1, 2 and 6)

Customers shall be subject to a charge, stated on a cents per Ccf basis and shown separately on the Statement of Monthly Gas Adjustment, to recover the costs associated with payments made to Sellers in accordance with General Information Section 11.1 (E) "Curtailement of Service" of this Rate Schedule.

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PSC NO. 4 GAS
ORANGE AND ROCKLAND UTILITIES, INC.
INITIAL EFFECTIVE DATE: December 26, 2008

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SUPERSEDING REVISION: 0

GENERAL INFORMATION

12. ADJUSTMENT OF RATES IN ACCORDANCE WITH CHANGES IN THE COST OF GAS (Cont'd.)

12.2 MONTHLY GAS ADJUSTMENT (Cont'd.)

(H) Statement of Monthly Gas Adjustment

- (1) The Monthly Gas Adjustment shall be effective for service rendered on and after the first day of the calendar month following the computation date and shall continue in effect until changed.
- (2) The Statement of Monthly Gas Adjustment shall be filed with the Public Service Commission and apart from this Rate Schedule not less than three days prior to the date on which it is proposed to be effective. Such Statement will be available to the public at Company offices at which applications for service may be made.

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GENERAL INFORMATION

12. ADJUSTMENT OF RATES IN ACCORDANCE WITH CHANGES IN THE COST OF GAS (Cont'd.)

12.3 WEATHER NORMALIZATION ADJUSTMENT

A Weather Normalization Adjustment shall be effective for all Service Classification Nos. 1 and 6 - Space Heating Customers and for Service Classification No. 2 - General Service Master Metered Multiple Dwellings, General Service Commercial and General Service Industrial Customers. The Weather Normalization Adjustment will be applied to total gas usage during the period October 1 through May 31 of each year.

(A) Definitions

- (1) PBR or pure base rate is the tail block delivery charge set forth in Service Classification Nos. 1, 2 and 6.
- (2) BD or billing days is the actual number of days for which service is being billed.
- (3) HDD or heating degree days are the difference between 63 degrees F. and the average outdoor dry bulb temperature for a day based on readings made every hour on the hour throughout the day. HDD are always zero when that average temperature is above 63 degrees F.
- (4) NHDD or normal heating degree days for the twelve-month period commencing November 1, 2009 shall be 5,065 heating degree days.
- (5) AHDD or actual heating degree days are the actual difference between 63 degrees F. and the average outdoor dry bulb temperature for a particular day or days based on readings made every hour on the hour throughout the day. AHDD are always zero when that average temperature is above 63 degrees F.
- (6) HDDF or heating degree day factor is the estimated number of ccf per customer needed to provide space heating for each degree of a degree day based on average usage by customers to which this adjustment applies. The HDDF shall be determined separately for each customer rate classification and shall be revised annually. The HDDF shall be submitted to Staff on or before August 31 for inclusion in the October 1 start date of each year's Weather Normalization Adjustment.

GENERAL INFORMATION

12. ADJUSTMENT OF RATES IN ACCORDANCE WITH CHANGES IN THE COST OF GAS
(Cont'd.)

12.3 WEATHER NORMALIZATION ADJUSTMENT (Cont'd)

(A) Definitions (Cont'd)

- (7) BL or base load per billing day is the estimated number of ccf per customer used per day for non-heating purposes based on average usage by customers to which this adjustment applies. BL shall be determined separately for each customer rate classification and shall be redetermined annually using the prior two heating seasons' sales.

(B) Determination of the Weather Normalization Adjustment

The Weather Normalization Adjustment shall be calculated for each billing cycle and shall be calculated separately for each customer rate classification. The Weather Normalization Adjustment shall be calculated using the following formula rounding to the nearest 0.001 cents per 100 cubic feet:

$$\begin{array}{lcl} \text{Weather Normalization} & & (\text{NHDD}-\text{AHDD}) * \text{HDDF} * \text{PBR} \\ \text{Adjustment} & = & \text{-----} \\ \text{(cents/ccf)} & & (\text{BL} * \text{BD}) + (\text{HDDF} * \text{AHDD}) \end{array}$$

(C) Operation of the Weather Normalization Adjustment

The Weather Normalization Adjustment as determined above, shall be included in the Monthly Gas Adjustment, which is provided for in Section 12.2 of this Schedule. The Company shall submit a schedule of all Weather Normalization Adjustments to Staff within seven working days following the end of each billing month.

PSC NO. 4 GAS LEAF: 81.1
ORANGE AND ROCKLAND UTILITIES, INC. REVISION: 6
INITIAL EFFECTIVE DATE: December 26, 2008 SUPERSEDING REVISION: 5

GENERAL INFORMATION

12. ADJUSTMENT OF RATES IN ACCORDANCE WITH CHANGES IN THE COST OF GAS (Cont'd.)

12.4 Merchant Function Charge (MFC)

(A) Applicability

Beginning November 1, 2006, customers taking service under Service Classification Nos. 1 and 2 of this Rate Schedule shall be subject to a Merchant Function Charge ("MFC"). Separate MFCs will be determined for Service Classification No. 1 and for Service Classification No. 2 of this Rate Schedule and will be applied to all gas volumes sold under such service classifications to recover the costs associated with commodity-related competitive services. Commodity-related costs include commodity procurement costs (including commodity revenue-based allocation of information resources and education and outreach costs), credit and collections costs, gas in storage working capital costs related to firm sales, and commodity-related uncollectibles.

(B) Fixed MFC Components

The fixed components of the MFC, effective November 1, 2009, are as follows:

<u>Service Classification</u>	<u>Cents per Ccf</u>		
	<u>Commodity Procurement, IR, and Education And Outreach</u>	<u>Credit and Collections</u>	<u>Total</u>
SC No. 1	1.127	0.647	1.774
SC No. 2	0.394	0.222	0.616

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(Name of Officer, Title, Address)

GENERAL INFORMATION

12. ADJUSTMENT OF RATES IN ACCORDANCE WITH CHANGES IN THE COST OF GAS (Cont'd.)

12.4 Merchant Function Charge (MFC) (Cont'd.)

(B) Fixed MFC Components (Cont'd.)

These fixed MFC components shall remain in effect until changed by an order of the Commission.

(C) Determination of MFCs

The MFCs applicable to Service Classification Nos. 1 and 2 customers shall be the sum of (1) the applicable fixed MFC components set forth; (2) a per Ccf charge, determined in accordance with General Information Section 12.2 (D) of this Rate Schedule, to recover gas in storage working capital costs associated with firm sales customers; and (3) the applicable monthly uncollectibles charge ("UC charge") per Ccf to recover the cost of commodity-related uncollectibles.

The monthly UC charge component of the MFC described in (3) above shall be based on the Gas Supply Charge ("GSC") determined in accordance with General Information Section 12.2 of this Rate Schedule and the uncollectibles percentage ("UC percentage") applicable to Service Classification No. 1 and the UC percentage applicable to Service Classification No. 2. The UC percentages shall be reset annually effective November 1 based on the Company's actual uncollectibles experience for the twelve month period ended the previous June 30 applicable to all electricity and gas customers eligible for the Company's Purchase of Receivables Program. The UC percentages effective for the twelve-month period commencing November 1, 2009 are 0.340 percent applicable to Service Classification No. 1 and 0.037 percent applicable to Service Classification No. 2. The UC charge component of the MFC shall be determined using the following formula rounding to the nearest 0.001 cents per Ccf:

$$\text{UC Charge} = \text{GSC} / (1 - \text{applicable UC percentage}) - \text{GSC}$$

(D) Reconciliation of Fixed MFC Components

Revenues associated with the fixed MFC components shall be reconciled annually in accordance with the operation of the Transition Adjustment for Competitive Services, as set forth in General Information Section 12.2 (B) of this Rate Schedule.

PSC NO. 4 GAS
ORANGE AND ROCKLAND UTILITIES, INC.
INITIAL EFFECTIVE DATE: December 26, 2008

LEAF: 94.9
REVISION: 4
SUPERSEDING REVISION: 3

GENERAL INFORMATION

SERVICE CLASSIFICATION RIDERS:

RIDER B (Continued)

ELIGIBILITY: (Continued)

service under this Rider in less than one year. Such allowance will be contingent on the customer reasonably demonstrating to the Company's satisfaction that the condition(s) that prevented the customer from maintaining an Annual Load Factor of at least 50 percent has been corrected and/or is not likely to recur in the next annual determination period.

RATE - FOUR PART - MONTHLY:

Customers served under Rate Schedule I or Rate Schedule II of this Rider will be subject to the higher of the Delivery Charges or the Monthly Minimum Charge determined in the manner set forth below.

(1) Delivery Charges

Rate Schedule I - Applicable to customers whose Distributed Generation Facility has a rated capacity of less than 5 MegaWatts.

Rate IA - Applicable to customers whose Distributed Generation Facility has a rated capacity of 0.25 MegaWatt or less.

<u>Usage Charge</u>	<u>Summer Months*</u>	<u>Winter Months*</u>
First 3 Ccf or less	@ \$114.91	\$114.91
Over 3 Ccf	@ 17.827 ¢ per Ccf	22.130 ¢ per Ccf

Rate IB - Applicable to customers whose Distributed Generation Facility has a rated capacity greater than 0.25 MegaWatt but less than or equal to 1 MegaWatt.

<u>Usage Charge</u>	<u>Summer Months*</u>	<u>Winter Months*</u>
First 3 Ccf or less	@ \$195.14	\$195.14
Over 3 Ccf	@ 17.827 ¢ per Ccf	22.130 ¢ per Ccf

*Summer Months are April through October, inclusive; Winter Months are November through March, inclusive.

(Continued)

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(Name of Officer, Title, Address)

PSC NO. 4 GAS
ORANGE AND ROCKLAND UTILITIES, INC.
INITIAL EFFECTIVE DATE: December 26, 2008

LEAF: 94.10
REVISION: 4
SUPERSEDING REVISION: 3

GENERAL INFORMATION

SERVICE CLASSIFICATION RIDERS:

RIDER B (Continued)

RATE - FOUR PART - MONTHLY: (Continued)

(1) Delivery Charges (Continued)

Rate IC - Applicable to customers whose Distributed Generation Facility has a rated capacity greater than 1 MegaWatt but less than or equal to 2 MegaWatts.

<u>Usage Charge</u>	<u>Summer Months*</u>	<u>Winter Months*</u>
First 3 Ccf or less	@ \$297.04	\$297.04
Over 3 Ccf	@ 17.827 ¢ per Ccf	22.130 ¢ per Ccf

Rate ID - Applicable to customers whose Distributed Generation Facility has a rated capacity greater than 2 MegaWatts but less than 5 MegaWatts.

<u>Usage Charge</u>	<u>Summer Months*</u>	<u>Winter Months*</u>
First 3 Ccf or less	@ \$377.26	\$377.26
Over 3 Ccf	@ 17.827 ¢ per Ccf	22.130 ¢ per Ccf

Rate Schedule II - Applicable to customers whose Distributed Generation Facility has a rated capacity of 5 MegaWatts or greater, but less than 50 MegaWatts.

<u>Usage Charge</u>	<u>Summer Months*</u>	<u>Winter Months*</u>
First 3 Ccf or less	@ \$ 43.36	\$ 43.36
Over 3 Ccf	@ 3.565 ¢ per Ccf	4.426 ¢ per Ccf

Contract Demand Charge - per Ccf of contract demand, as described in the "Determination of Contract Demand" section of this Rider.

Contract Demand Ccf @ \$31.52 per Ccf

*Summer Months are April through October, inclusive; Winter Months are November through March, inclusive.

(Continued)

Issued By: John D. McMahon, President, Pearl River, New York
(Name of Officer, Title, Address)

PSC NO. 4 GAS
ORANGE AND ROCKLAND UTILITIES, INC.
INITIAL EFFECTIVE DATE: December 26, 2008

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REVISION: 6
SUPERSEDING REVISION: 5

GENERAL INFORMATION

SERVICE CLASSIFICATION RIDERS:

RIDER B (Continued)

RATE - FOUR PART - MONTHLY: (Continued)

(2) Monthly Minimum Charge

Customers served under this Rider will be subject to a Monthly Minimum Charge, determined in the manner set forth below.

For customers served under Rate Schedule I of this Rider, the Monthly Minimum Charge shall be the charge for the first 3 Ccf of gas. For customers served under Rate Schedule II of this Rider, the Monthly Minimum Charge shall be (1) the charge for the first 3 Ccf of gas plus (2) the Contract Demand Charge.

(3) Monthly Gas Adjustment

The provisions of the Company's Monthly Gas Adjustment as described in General Information Section No. 12 shall apply to all gas delivered under this Rider, except that the Interim Back-out Lost Revenue Adjustment described in General Information Section 12.2 (F) shall not apply to Service Classification No. 6 customers taking service under Rate Schedule II of this Rider.

(4) Other Applicable Charges

In addition to the above Delivery Charge, Monthly Minimum Charge, and Monthly Gas Adjustment, the applicable rate and other provisions of the customer's otherwise applicable service classification shall apply to service rendered hereunder. The provisions of General Information Section 24, Revenue Decoupling Mechanism Adjustment, are not applicable to customers taking service under this Rider.

TERM:

Fifteen months from the date of commencement of service hereunder and successive annual periods thereafter; terminable by the customer or the Company at the end of each annual period upon not less than 30 days prior notice in writing to the other party, except that the 30 day notice period shall not apply in cases where the customer becomes ineligible for service hereunder for failure to maintain an Annual Load Factor of 50 percent or more. The Company may also terminate service in the manner provided by law and provisions of this Rate Schedule. In addition to all other remedies available to the Company, the Company reserves the right to discontinue service immediately, temporarily or permanently, to the customer or to the premises where there is a violation or any failure to comply with any of the provisions of this Rider, the Company's Gas Transportation Operating Procedures, or this Rate Schedule.

(Continued)

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(Name of Officer, Title, Address)

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INITIAL EFFECTIVE DATE: December 26, 2008 SUPERSEDING REVISION: 6

GENERAL INFORMATION

SERVICE CLASSIFICATION RIDERS:

RIDER C (Continued)

ELIGIBILITY:

Available to any residential customer who is eligible to take service under Service Classification Nos. 1 or 6 of this Rate Schedule, upon written application and acceptance by the Company, subject to the provisions of this Rider and the applicable provisions of the customer's otherwise applicable service classification.

Prior to the commencement of service hereunder, the customer shall provide the Company with a reasonable estimate of customer's Winter Peak Day Gas Usage and the customer's annual gas usage during the first year of operation of the customer's Distributed Generation Facility, with the first year commencing after a three-month start-up phase ("the first year"). In the event a customer does not provide the Company with the required information, the Company will attempt to estimate the customer's Annual Load Factor using the best available information.

The customer's Annual Load Factor shall be computed after the first fifteen monthly billing periods hereunder (based on the most recent 12 monthly billing periods) and annually thereafter for the purpose of data collection and reporting requirements of the Commission.

RATE - TWO PART - MONTHLY:

The rates and charges set forth below will apply to the customer's total monthly-metered gas usage.

(1) Delivery Charges

Usage Charge

First 3 Ccf or less @ \$26.48
Over 3 Ccf @ 14.505 ¢ per Ccf

(2) Other Applicable Charges

In addition to the above Delivery Charges, the applicable rate and other provisions of the customer's otherwise applicable service classification shall apply to service rendered hereunder. The provisions of General Information Section 24, Revenue Decoupling Mechanism Adjustment, are not applicable to customers taking service under this Rider.

(Continued)

Issued By: John D. McMahon, President, Pearl River, New York
(Name of Officer, Title, Address)

GENERAL INFORMATION

24. REVENUE DECOUPLING MECHANISM ("RDM") ADJUSTMENT

Actual delivery revenues for certain customer classes are subject to reconciliation through an RDM Adjustment. The RDM Adjustment is applicable to Service Classification Nos. 1, 2, and 6. For purposes of applying the RDM Adjustment, these service classifications shall be assigned to service classification groups as follows:

Group A - Service Classification No. 1 and 6 residential customers.

Group B - Service Classification No. 1, 2 and 6 non-residential customers.

The RDM is not applicable to customers taking service under Riders B and C.

(A) Determination of RDM Adjustment

For each service classification group subject to the RDM Adjustment, the Company will compare, on a monthly basis, the difference between actual delivery revenue and corresponding delivery revenue targets. Actual delivery revenue, determined for each customer class on a monthly basis, is defined as the sum of (a) total revenue derived from delivery charges, as defined in Service Classification Nos. 1 and 2; (b) transportation charges as defined in Service Classification No. 6; and (c) revenues derived from the weather normalization adjustment. Actual delivery revenue shall not include revenues derived from the RDM Adjustment.

For each service classification group subject to the RDM Adjustment, the Company will, on a monthly basis, compare actual delivery revenue to a delivery revenue target. If the monthly actual delivery revenue exceeds the delivery revenue target, the delivery revenue excess will be accrued for refund to customers at the end of the Annual RDM Period as defined below. Likewise, if the monthly actual delivery revenue is less than the delivery revenue target, this delivery revenue shortfall will be accrued for recovery from customers at the end of the Annual RDM Period.

On a monthly basis, interest at the Commission's rate for other customer provided capital will be calculated on the average of the current and prior month's cumulative delivery revenue excess/shortfall (net of state and federal income tax benefits).

GENERAL INFORMATION

24 REVENUE DECOUPLING MECHANISM ("RDM") ADJUSTMENT (Continued)

(A) Determination of RDM Adjustment (Continued)

At the end of an Annual RDM Period, as defined below, total delivery revenue excess/shortfalls for each service classification group will be refunded/surcharged to customers through service classification group-specific RDM Adjustments applicable during a corresponding RDM Adjustment Period as defined below. The RDM Adjustment for each applicable service classification group shall be determined by dividing the amount to be refunded/surcharged to customers in that service classification group by estimated Ccf deliveries to customers in that service classification group over the RDM Adjustment Period. RDM Adjustments shall be rounded to the nearest \$0.00001 per Ccf.

Following each RDM Adjustment Period, any difference between amounts required to be charged or credited to customers in each service classification group and amounts actually charged or credited will be charged or credited to customers in that service classification group, with interest, over a subsequent RDM Adjustment period, or as determined by the Commission if no RDM is in effect.

<u>Annual RDM Period</u>	<u>RDM Adjustment Filing Date</u>	<u>RDM Adjustment Period</u>
11/1/09-10/31/10	11/21/10	12/1/10 - 11/30/11

GENERAL INFORMATION

24 REVENUE DECOUPLING MECHANISM ("RDM") ADJUSTMENT (Continued)

(B) Delivery Revenue Targets (\$000s)

12-month period
commencing:

<u>Service Classification Group</u>	<u>November 1, 2009</u>
A	\$78,813
B	23,437
Total	\$102,250

(C) Interim RDM Adjustments

If at any time during an Annual RDM Period, the total of cumulative delivery revenue excess/shortfall for all of the Company's service classification groups subject to the RDM Adjustment exceeds \$3 million, the Company will implement interim RDM Adjustments by service classification groups on no less than ten days notice. These interim RDM Adjustments are subject to reconciliation at the end of the Annual RDM Period as part of the annual RDM Adjustment process described above.

(D) Statement of RDM Adjustments

A Statement of RDM Adjustments, showing the RDM Adjustments by service classification group and their effective date shall be filed with the Commission, apart from this Schedule. Such statement shall be filed not less than ten calendar days prior to a proposed change in RDM Adjustments. The Statement of RDM Adjustments shall be made available to the public at Company offices where applications for service may be made.

PSC NO. 4 GAS
ORANGE AND ROCKLAND UTILITIES, INC.
INITIAL EFFECTIVE DATE: December 26, 2008

LEAF: 114
REVISION: 17
SUPERSEDING REVISION: 16

SERVICE CLASSIFICATION NO. 1

APPLICABLE TO USE OF SERVICE FOR:

Residential and Space Heating service in the entire territory subject to the restrictions described in General Information Section 11. The total hourly input of a Commercial or Industrial Customer's space heating equipment shall not be more than 500,000 Btu except that the upper limit may be 1,000,000 Btu in the case of space heating service to Churches, Schools and Hospitals.

CHARACTER OF SERVICE:

Continuous; natural gas (or, in the case of emergency or for economy of operation, a mixture of natural and liquefied petroleum gas) of a Btu content per cubic foot of not less than 1,000 Btu on a monthly average, supplied at pressures within the limits prescribed in Title 16 Public Service, Part 255.60, the official compilation, Codes, Rules and Regulations of the State of New York.

RATE - NINE PART - MONTHLY:

(1) Delivery Charge

First 3 Ccf or less.....@	\$ 18.22
Next 47 Ccf.....@	41.929 ¢ per Ccf
All over 50 Ccf.....@	40.354 ¢ per Ccf

(2) Gas Supply Charge

The Gas Supply Charge as described in General Information Section 12.1 shall apply to all gas sold under this Service Classification.

(3) Merchant Function Charge

The Merchant Function Charge as described in General Information Section 12.4 shall apply to all gas sold under this Service Classification.

(4) Monthly Gas Adjustment

The Monthly Gas Adjustment as described in General Information Section 12.2 shall apply to all gas sold under this Service Classification.

(5) Unauthorized Use of Gas

As explained in General Information Section 11.1.

(6) Billing and Payment Processing Charge

Customers shall be subject to a charge of \$1.02 per billing cycle. This charge will be applied only once to a dual service customer bill.

Issued By: John D. McMahon, President, Pearl River, New York
(Name of Officer, Title, Address)

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ORANGE AND ROCKLAND UTILITIES, INC. REVISION: 11
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SERVICE CLASSIFICATION NO. 1 (Cont'd.)

RATE - NINE PART - MONTHLY: (Continued)

(7) Systems Benefits Charge

The Systems Benefits Charge as described in General Section 23 shall apply to all gas sold to residential customers under this Service Classification.

(8) Revenue Decoupling Mechanism Adjustment

The provisions of the Company's Revenue Decoupling Mechanism Adjustment as described in General Information Section 24 shall apply to gas delivered under this Service Classification.

(9) Increase in Rates and Charges

The rates and charges under this Service Classification will be increased pursuant to General Information Section 15.

TERMS OF PAYMENT:

Bills are due when rendered, subject to late payment charge in accordance with provisions of General Information Section 6.6. If bill is not paid, service may be discontinued in accordance with provisions of General Information Section 9.1 and 9.2.

TERM:

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

SPECIAL PROVISIONS:

Budget Billing (Optional)

Any residential customer or customer who is a condominium association or cooperative housing corporation taking service hereunder, and any other customer who has taken service hereunder for at least twelve months, may, upon request, be billed monthly in accordance with the budget billing plan provided for in General Information Section 6 of this tariff.

Issued By: John D. McMahon, President, Pearl River, New York
(Name of Officer, Title, Address)

PSC NO. 4 GAS LEAF: 116
ORANGE AND ROCKLAND UTILITIES, INC. REVISION: 19
INITIAL EFFECTIVE DATE: December 26, 2008 SUPERSEDING REVISION: 18

SERVICE CLASSIFICATION NO. 2

APPLICABLE TO USE OF SERVICE FOR:

General service in the entire territory subject to the restrictions described in General Information Section 11.

CHARACTER OF SERVICE:

Continuous; natural gas (or, in the case of emergency or for economy of operation, a mixture of natural and liquefied petroleum gas) of a Btu content per cubic foot of not less than 1,000 Btu on a monthly average, supplied at pressures within the limits prescribed in Title 16 Public Service, Part 255.60, the official compilation, Codes, Rules and Regulations of the State of New York.

RATE - EIGHT PART - MONTHLY:

(1) Delivery Charge

First	3 Ccf or less.....@	\$27.33
Next	47 Ccf.....@	34.258 ¢ per Ccf
Next	4,950 Ccf.....@	32.891 ¢ per Ccf
All over	5,000 Ccf.....@	29.085 ¢ per Ccf

(2) Gas Supply Charge

The Gas Supply Charge as described in General Information Section 12.1 shall apply to all gas sold under this service classification.

(3) Merchant Function Charge

The Merchant Function Charge as described in General Information Section 12.4 shall apply to all gas sold under this Service Classification.

(4) Monthly Gas Adjustment

The Monthly Gas Adjustment as described in General Information Section 12.2 shall apply to all gas sold under this Service Classification.

(5) Unauthorized Use of Gas

As explained in General Information Section 11.1.

(6) Billing and Payment Processing Charge

Customers shall be subject to a charge of \$1.02 per billing cycle. This charge will be applied only once to a dual service customer bill.

Issued By: John D. McMahon, President, Pearl River, New York
(Name of Officer, Title, Address)

PSC NO. 4 GAS
ORANGE AND ROCKLAND UTILITIES, INC.
INITIAL EFFECTIVE DATE: December 26, 2008

LEAF: 117
REVISION: 9
SUPERSEDING REVISION: 8

SERVICE CLASSIFICATION NO. 2 (Cont'd.)

RATE - EIGHT PART - MONTHLY: (Continued)

(7) Revenue Decoupling Mechanism Adjustment

The provisions of the Company's Revenue Decoupling Mechanism Adjustment as described in General Information Section 24 shall apply to gas delivered under this Service Classification.

(8) Increase in Rates and Charges

The rates and charges under this Service Classification will be increased pursuant to General Information Section 15.

TERMS OF PAYMENT:

Bills are due when rendered, subject to late payment charge in accordance with provisions of General Information Section 6.6. If bill is not paid, service may be discontinued in accordance with provisions of General Information Section 9.1 and 9.2.

TERM:

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

SPECIAL PROVISIONS:

Budget Billing (Optional)

Any condominium association or cooperative housing corporation taking service hereunder, and any other customer who has taken service hereunder for at least twelve months, may, upon request, be billed monthly in accordance with the budget billing plan provided for in General Information Section 6 of this tariff.

Issued By: John D. McMahon, President, Pearl River, New York
(Name of Officer, Title, Address)

PSC NO. 4 GAS LEAF: 130
ORANGE AND ROCKLAND UTILITIES, INC. REVISION: 18
INITIAL EFFECTIVE DATE: December 26, 2008 SUPERSEDING REVISION: 17

SERVICE CLASSIFICATION NO. 6 (Cont'd.)

RATE - FOUR PART - MONTHLY:

(1) Transportation Charge

Rate Schedule IA: Applicable to any customer otherwise eligible for Service Classification No. 1 and:

- a) is a member of an aggregated group, or
- b) is an individual customer whose annual usage is less than 5,000 Mcf.

First	3 Ccf or less.....@	\$18.22
Next	47 Ccf.....@	41.929 ¢ per Ccf
Over	50 Ccf.....@	40.354 ¢ per Ccf

Rate Schedule IB: Applicable to any customer otherwise eligible for Service Classification No. 2 and:

- a) is a member of an aggregated group, or
- b) is an individual customer whose annual usage is less than 5,000 Mcf.

First	3 Ccf or less.....@	\$27.33
Next	47 Ccf.....@	34.258 ¢ per Ccf
Next	4950 Ccf.....@	32.891 ¢ per Ccf
Over	5,000 Ccf.....@	29.085 ¢ per Ccf

Rate Schedule II:

Applicable to any customer that is not a member of an aggregated group and whose usage exceeds 5,000 Mcf in the previous consecutive twelve-month period. Customers using less than 5,000 Mcf in a consecutive twelve-month period shall be transferred to Rate Schedule I.

First	100 Ccf or less.....@	\$206.70
Over	100 Ccf.....@	29.085 ¢ per Ccf

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(Name of Officer, Title, Address)

PSC NO. 4 GAS LEAF: 130.1
ORANGE AND ROCKLAND UTILITIES, INC. REVISION: 2
INITIAL EFFECTIVE DATE: December 26, 2008 SUPERSEDING REVISION: 1

SERVICE CLASSIFICATION NO. 6 (Cont'd.)

RATE - FOUR PART - MONTHLY:

(2) Balancing Service Option or Winter Bundled Sales Service Option

Upon applying for firm transportation service under Service Classification No. 6, a customer must elect either the Balancing Service Option or Winter Bundled Sales Service Option.

(A) Balancing Service Option

The Balancing Service Option provides for a Seller to deliver gas to the Company's citygate on behalf of all of its customers in the Seller's Aggregation Group based on the customers' average daily usage for the same month last year, weather normalized and restated on a calendar month basis, with the Company redelivering the gas to the Seller's customers on an as needed basis. A customer selecting the Balancing Service Option shall be required to pay the Balancing Fee as set forth in 2(D) below.

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(Name of Officer, Title, Address)

PSC NO. 4 GAS
ORANGE AND ROCKLAND UTILITIES, INC.
INITIAL EFFECTIVE DATE: December 26, 2008

LEAF: 131
REVISION: 9
SUPERSEDING REVISION: 8

SERVICE CLASSIFICATION NO. 6 (Cont'd.)

RATE - FOUR PART - MONTHLY: (Cont'd.)

(2) Balancing Service Option or Winter Bundled Sales Service Option
(Cont'd.)

(B) Winter Bundled Sales Service Option

The Winter Bundled Sales Service Option provides for a Seller to deliver gas to the Company's citygate on behalf of all customers in the Seller's Aggregation Group based on the customers' average daily usage for the same month last year, weather-normalized, with the Company redelivering the gas to the Seller's customers on an as-needed basis, except that a portion of the Seller's customers total gas requirements during the period November through March (winter period) shall include an amount of WBS gas purchased by the Seller from the Company in accordance with and at the rates set forth in Service Classification No. 11 of this Rate Schedule.

(C) Peak Shaving Supply Fee

Customers that elect either the Balancing Service Option or the Winter Bundled Sales Service Option will be assessed the Peak Shaving Supply Fee when propane is used by the Company to meet the system requirements of all firm sales and transportation customers. Customers will be assessed the Peak Shaving Supply Fee based on the customer's Ccfs of annual usage to recover the cost of any propane used by the Company. The Peak Shaving Supply Fee shall be determined by dividing the cost of propane used in any twelve-month (12) period by the quantity of gas delivered to Service Classification Nos. 1, 2, 5 and 6, during the same period, all as set forth in the determination of the Company's Monthly Gas Adjustment.

(D) Balancing Fee

For customers opting for the Balancing Service, if the customer's average daily usage of gas in any of the months of November through March exceeds the average daily usage during the preceding billing months of June through September ("Average Daily Summer Usage"), the volume used in such month in excess of the product of the Average Daily Summer Usage times the number of days in the billing month shall be

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(Name of Officer, Title, Address)

PSC NO. 4 GAS
ORANGE AND ROCKLAND UTILITIES, INC.
INITIAL EFFECTIVE DATE: December 26, 2008

LEAF: 132
REVISION: 9
SUPERSEDING REVISION: 8

SERVICE CLASSIFICATION NO. 6 (Cont'd.)

RATE - FOUR PART - MONTHLY: (Cont'd.)

(2) Balancing Service Option or Winter Bundled Sales Service Option
(Cont'd.)

(D) Balancing Fee (Cont'd.)

subject to the Balancing Fee. For new customers and for customers who install additional gas-burning equipment, the Average Daily Summer Usage to be used in the above calculation shall be estimated by the Company.

The Balancing Fee, as defined below, shall be assessed on each Ccf of Balancing Service rendered pursuant to Service Classification No. 6. The Balancing Fee shall equal the sum of the Company's annualized fixed storage charges and fixed pipeline transportation charges from storage to the pipeline delivery point(s) at the boundary of the Company's service territory divided by System Balancing capability, all as set forth in the determination of the Company's monthly Gas Adjustment Charge.

- (E) The Balancing Fee in 2(D), and the Peak Shaving Supply Fee in 2(C) shall be shown as separate line items in the Statement of Statement of Monthly Gas Adjustments as filed with the Commission each month. The Balancing Fee will be billed only during the months of November through March.

(3) Revenue Decoupling Mechanism Adjustment

The provisions of the Company's Revenue Decoupling Mechanism Adjustment as described in General Information Section 24 shall apply to gas delivered under this Service Classification.

(4) Increase in Rates and Charges

- (A) The provisions of the Company's Monthly Gas Adjustment as described in General Information Section No. 12 shall apply to all volumes delivered under this Service Classification.
- (B) During the period October 1 through May 31 of each year, all volumes of gas used under this Service Classification shall be assessed the Weather Normalization Adjustment pursuant to General Information Section 12.3.

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(Name of Officer, Title, Address)

PSC NO. 4 GAS	LEAF:	133
ORANGE AND ROCKLAND UTILITIES, INC.	REVISION:	20
INITIAL EFFECTIVE DATE: December 26, 2008	SUPERSEDING REVISION:	19

SERVICE CLASSIFICATION NO. 6 (Cont'd.)

RATE - FOUR PART - MONTHLY: (Cont'd.)

(4) Increase in Rates and Charges (Cont'd.)

- (C) A billing and payment processing charge of \$1.02 per billing cycle shall apply to customers electing the Two Separate Bills billing option under General Information Section 6.5 (2) of this Rate Schedule. This charge will be applied only once to a dual service customer bill.
- (D) All rates and charges under this Service Classification will be increased pursuant to General Information Section 15.
- (E) The Systems Benefits Charge as described in General Information Section 23 shall apply to all gas volumes delivered to residential customers under this Service Classification.

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(Name of Officer, Title, Address)

PSC NO. 4 GAS
ORANGE AND ROCKLAND UTILITIES, INC.
INITIAL EFFECTIVE DATE: December 26, 2008

LEAF: 137
REVISION: 8
SUPERSEDING REVISION: 7

SERVICE CLASSIFICATION NO. 8

APPLICABLE TO USE OF SERVICE FOR:

Interruptible transportation service for customer-owned gas from a receipt point to the customer's facilities. Customers commencing service hereunder on or after November 1, 2006 are subject to the gas usage eligibility requirement set forth in Special Provision I of this Service Classification. Effective November 1, 2009, this Service Classification is closed to new customers. A receipt point is an agreed upon pipeline delivery point that interconnects with the Company's distribution system. The customer or a customer's gas Seller is responsible for transporting the gas to the receipt point including an amount to compensate the Company for losses incurred in transporting customer's gas. Customers electing interruptible transportation service under this Service Classification must be located adjacent to the Company's existing gas distribution mains having adequate capacity to supply customer's prospective requirements, in addition to the requirements of other present or prospective customers taking firm or interruptible service from such distribution mains or who agree to pay to the Company, prior to construction, the estimated cost of expanding its distribution system to make it adequate for service hereunder and who agree to:

- (a) interruption of service at any time at the Company's option on not less than four hours notice;
- (b) install and maintain facilities for using alternate fuels during interruptions; and
- (c) not use service supplied hereunder in any equipment which is supplied with gas service under any other Service Classification except as specified herein.

CHARACTER OF SERVICE:

- (A) Interruptible transportation of natural gas owned by a customer which the customer has arranged to have transported to a receipt point which interconnects with the Company's gas distribution system. Such gas will be transported from that receipt point to the customer's facilities. The Company shall control the dispatch of such gas, and dispatch will be provided as requested by the customer, except that the volume of gas delivered shall be conditioned upon the availability of distribution system capacity not then being used by Orange and Rockland's customers being served under Service Classification Nos. 1, 2, 5, 6, 7, 9 and 10.
- (B) Customers have the option, in lieu of the interruptible transportation service provided in (A) above, to purchase Supplemental Sales Service on a monthly basis. Supplemental Sales Service is the sale of interruptible natural gas owned by the Company having a heating value of not less than 1,000 Btu per cubic foot delivered at a pressure agreed upon by the customer and the Company, but not in excess of the available pressure at the point of delivery, as determined by the Company. To purchase Supplemental Sales Service, a customer must notify the Company by the twenty-fifth day of any month to commence Supplemental Sales

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(Name of Officer, Title, Address)

PSC NO. 4 GAS
ORANGE AND ROCKLAND UTILITIES, INC.
INITIAL EFFECTIVE DATE: December 26, 2008

LEAF: 137.2
REVISION: 6
SUPERSEDING REVISION: 5

SERVICE CLASSIFICATION NO. 8 (Cont'd.)

RATE - FOUR PART - MONTHLY: (Cont'd)

(1) Transportation Charge (Cont'd)

The Base Charge per 100 cubic feet (Ccf) shall be established each month at the Company's discretion, not less than three working days prior to the first day of the billing period for which such Base Charge is to be effective.

The Base Charge shall not be less than \$0.010 per Ccf.

The Base Charge shall not be greater than (i) the lowest per unit delivery charge for service under Service Classification No. 6 of this Schedule minus (ii) 5.0 cents per Ccf.

(2) Over and Under-delivery Charges

If the amount of gas delivered to the Company by a customer electing interruptible transportation service varies from the amount of gas used by the customer on a daily basis, (adjusted for losses as defined in Special Provision D "Loss Adjusted Usage"), the customer will have an over-delivery or an under-delivery. If on any day the over-delivery or under-delivery is less than 10% of a customer's actual daily Loss Adjusted Usage, the customer may adjust subsequent daily deliveries to the Company by an amount not to exceed 10% of any day's Loss Adjusted Usage to eliminate any over- or under-deliveries by the end of the month. Any over- or under-delivery remaining at the end of each month will be cashed out. To cash out over- or under-deliveries, the customer must sell the over-delivered volumes to the Company or purchase the under-delivered volumes from the Company as specified below.

(a) Over-deliveries - Daily

If on any day a customer's over-delivery is greater than 10% of a customer's actual Loss Adjusted Usage, the over-delivered volumes in excess of 10% will be purchased by the Company at the rates set forth below. The Index Price used to determine the applicable rate shall be equal to the highest "Midpoint" rate of the "Louisiana-Onshore South", "Tennessee" receipt points for the applicable day as published in Gas Daily in the table "Daily Price Survey", plus the Company's weighted average cost of transportation (WACOT) and fuel losses calculated at 100% load factor.

Issued By: John D. McMahon, President, Pearl River, New York
(Name of Officer, Title, Address)

	PSC NO. 4 GAS	LEAF: 152.3
ORANGE AND ROCKLAND UTILITIES, INC.		REVISION: 3
INITIAL EFFECTIVE DATE: December 26, 2008	SUPERSEDING REVISION:	2

SERVICE CLASSIFICATION NO. 11 (Cont'd.)

BALANCING SERVICE OPTION:

For Balancing Service Option customers, the DCQ for each calendar month shall be calculated by the Company by dividing each customer's weather-normalized usage for each month of the most recent twelve billing months by the total number of days in each billing month and restating the billing month usage on a calendar month basis. The Company may adjust each customer's DCQs during the year due to changes in the customer's gas equipment or pattern of usage. For new customers, the initial monthly DCQ will be estimated by the Company based on the rating of the customer's gas-fired equipment and the expected utilization of such equipment.

The daily DCQs determined, as set forth above, reported on a volumetric basis shall be aggregated by month for each of the twelve months for all Balancing Service Option customers within a Seller's Aggregation Group. The result obtained shall be the monthly ADCQ. The monthly ADCQ shall be multiplied by the Company's factor of adjustment as defined in General Information Section 12 and then converted to an energy basis by using the conversion factor shown in the Statement of Monthly Gas Adjustment. The highest ADCQ determined in the twelve-month period is the ("MAX ADCQ"). Seller shall be obligated to deliver the ADCQ each day during the month.

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(Name of Officer, Title, Address)

PSC NO. 4 GAS
ORANGE AND ROCKLAND UTILITIES, INC.
INITIAL EFFECTIVE DATE: December 26, 2008

LEAF: 153
REVISION: 10
SUPERSEDING REVISION: 9

SERVICE CLASSIFICATION NO. 11 (Cont'd.)

BALANCING SERVICE OPTION: (Cont'd.)

Monthly Cash-out

For each month the Company will calculate the difference between the Seller's Balancing Service Option customer's actual usage and the ADCQ multiplied by the number of days in the billing period. If there is an imbalance at the end of the month, the over-delivered volumes will be purchased by the Company from the Seller and the under-delivered volumes will be sold by the Company to the Seller at a rate equal to the monthly average of the highest daily "Midpoint" rate of the "Louisiana - Onshore South", "Tennessee" receipts points for such month as published in Gas Daily in the table "Daily Price Survey", plus the Company's Adjusted WACOT for such month and fuel losses calculated at 100% load factor.

The MAX ADCQ shall be the amount of daily pipeline capacity to be obtained by the Seller. The ADCQ is the amount of gas that Seller must deliver to the Company daily. If Seller is also serving customers that have elected the Winter Bundled Sales Service Option, the ADCQ and the MAX ADCQ determined for the Winter Bundled Sales Service Option shall be added to the ADCQ and MAX ADCQs determined herein.

WINTER BUNDLED SALES SERVICE OPTION:

For customers electing the Winter Bundled Sales ("WBS") Service Option pursuant to Service Classification No. 6, the Company will provide to the Seller the Winter Bundled Sales Volume ("WBSV"), the ADCQ, and the MAX ADCQ for its customers as defined and determined in the manner set forth below:

- a) The WBSV shall be equal to the sum of the WBS gas allocated to each customer in Seller's Aggregation Group multiplied by the Company's factor of adjustment as defined in General Information Section 12 and then converted to an energy basis by using the conversion factor shown in the Statement of Monthly Gas Adjustments. The Seller is required to purchase the WBSV from the Company during the period November through March (winter period) in accordance with the provisions set forth below. Each customer will be allocated a portion of the WBSV based on the percentage of the Company's system gas requirements that are served by storage service. If there is a change in the percentage of the Company's system requirements that are met through storage service, the new percentage will be used to re-determine the allocated volume of WBSV the following April. WBSV is to be measured in Dths.

Issued By: John D. McMahon, President, Pearl River, New York
(Name of Officer, Title, Address)

	PSC NO. 4 GAS	LEAF: 154.1
ORANGE AND ROCKLAND UTILITIES, INC.		REVISION: 4
INITIAL EFFECTIVE DATE: December 26, 2008	SUPERSEDING REVISION:	3

SERVICE CLASSIFICATION NO. 11 (Cont'd.)

WINTER BUNDLED SALES SERVICE OPTION: (Cont'd.)

Monthly Cash-out

For each month the Company will calculate the difference between the Seller's Winter Bundles Sales Service Option customer's actual usage and the ADCQ, adjusted for WBS volumes, multiplied by the number of days in the billing period. If there is an imbalance at the end of the month, the over-delivered volumes will be purchased by the Company from the Seller and the under-delivered volumes will be sold by the Company to the Seller at a rate equal to the monthly average of the highest daily "Midpoint" rate of the "Louisiana - Onshore South", "Tennessee" receipts points for such month as published in Gas Daily in the table "Daily Price Survey", plus the Company's Adjusted WACOT for such month and fuel losses calculated at 100% load factor.

Issued By: John D. McMahon, President, Pearl River, New York
(Name of Officer, Title, Address)

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
ACCOUNTING PANEL

NYPSC CASE No. _____

1 Q. Please state your names and business addresses.

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

3 Richard A. Kane, 4 Irving Place, New York, New York 10003.

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

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

6 A. **(Kosior)** I am employed by Orange and Rockland Utilities, Inc. ("Orange and
7 Rockland", "O&R", or the "Company") where I hold the position of Director –
8 Financial Services.

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

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

14 Q. Please explain your educational background, work experience, and current
15 general responsibilities.

16 A. **(Kosior)** I graduated from Pace University in 1976 with a Bachelor of
17 Business Administration degree, having majored in Accounting. In June 1980,
18 I received a Masters of Business Administration degree from Fairleigh
19 Dickinson University, having majored in Accounting and Finance. After
20 graduation from Pace, I was employed by Homa Company as a staff
21 accountant. I joined Orange and Rockland in July 1979 as an Associate

ACCOUNTING PANEL

1 Accountant advancing to Supervisor-Payroll, Supervisor & Manager-General
2 Accounting where I had the responsibility of administering and supervising all
3 employee related payroll records and subsequently the books and records of
4 Orange and Rockland and its subsidiaries, including Pike County Light &
5 Power Company ("Pike") and Rockland Electric Company ("RECO"). In June
6 1989, I was promoted to Manager-Budgets and was responsible for the
7 development and management of the operating and capital budgets. My
8 additional duties included forecasting and analyzing the corporate financial
9 statements. I was named Strategic Analysis Principal in October 1994 and
10 became responsible for developing, analyzing and evaluating corporate
11 direction and business opportunities. In June 1995, I was promoted to Director
12 of Accounting, where I was responsible for the accounting functions of Orange
13 and Rockland and its subsidiaries, including the consolidated financial
14 statements. In July 1999, as a result of the merger involving Con Edison and
15 Orange and Rockland, I was appointed Director-Financial Planning and
16 Administration, now called Financial Services, responsible for providing the
17 coordination for administration, financial, budget and regulatory activities
18 between Con Edison and Orange and Rockland. I have been a member of
19 various accounting and finance committees of the Edison Electric Institute and
20 Pennsylvania Electric Association. In addition, I am a past Chairperson of the
21 New Jersey Utilities Association Accounting and Finance Committee.
22 **(Kane)** I received a Bachelor of Science degree in Accounting from Manhattan
23 College in May 1976. I worked for Con Edison from August 1976 until

ACCOUNTING PANEL

1 January 1978, as a staff accountant. I then joined Orange and Rockland and
2 became Supervisor - Facility Accounting. In 1980, I became Manager -
3 Budgets. In 1989, I became Manager - General Accounting, and in 1996, the
4 Accounts Payable Section was added to my responsibilities. As a result of the
5 merger involving Orange and Rockland and Con Edison, Orange and
6 Rockland's Accounting Department was combined with Con Edison's and
7 relocated to Con Edison's headquarters in New York City. Since the merger, I
8 continued to be responsible for overseeing Orange and Rockland's General
9 Accounting Section and Financial Reporting area until March 2003. At that
10 time, I assumed my current position as Manager of the Regulatory Filing
11 Section within Con Edison's Corporate Accounting Department where I
12 oversee rate case revenue requirement calculations and supporting
13 documentation as well as Accounting Petitions filed in New York, New Jersey
14 and Pennsylvania.

15 **(Prager)** I received a Bachelor of Science degree in Accounting from Yeshiva
16 University in 1988. I started my career at Con Edison in July 1988 as a
17 management intern. From July 1989 through September 1998, I worked in
18 Accounting Research and Procedures. From October 1998 through March
19 2000, I worked in General Accounts. Since April 2000, I have been working
20 in Regulatory Filings, coordinating the rate cases of Con Edison and Orange
21 and Rockland and its subsidiaries.

22 Q. Have you previously testified before the New York Public Service
23 Commission ("NYPSC" or "Commission")?

ACCOUNTING PANEL

1 A. **(Kosior)** Yes, I have previously submitted testimony in various cases.

2 **(Kane)** Yes, I have previously submitted testimony in various cases.

3 **(Prager)** No.

4 Q. What is the purpose of your testimony?

5 A. We sponsor, in summary:

- 6 • An overview of the items driving O&R's request for a gas rate
- 7 increase for the rate year ending October 31, 2010;
- 8 • Historic financial statements and statistical data;
- 9 • Cost allocation procedures;
- 10 • The average rate base for the rate year and earnings base /
- 11 capitalization adjustment;
- 12 • The gas income statement and rate of return, other operating
- 13 revenues, depreciation, taxes other than income taxes, income
- 14 taxes, and the source and use of funds;
- 15 • Certain operating and maintenance expense cost elements and the
- 16 amortizations of deferred charges;
- 17 • Common Utility Plant spending and additions;
- 18 • General Inflation Factor;
- 19 • The Company's alternative proposal for a three-year gas rate plan;
- 20 • The Company's proposal for a Distribution Infrastructure
- 21 Surcharge; and
- 22 • An outline of the Company's request for permission to continue the
- 23 use of true-ups and deferred accounting for certain operating costs

ACCOUNTING PANEL

1 as previously authorized by the Commission and to request
2 authorization to utilize several new true-up mechanisms.

3 We are sponsoring the following exhibits and schedules:

4	<u>Description of Schedule</u>	<u>Exhibit</u>
5	Historical Financial Data	G-1
6	Average Gas Rate Base	G-2
7	Gas Income Statement and Rate of Return	G-4, Sch. 1 – 7
8	Fund Requirements and Sources	G-4, Sch. 8
9	Gas Operation and Maintenance (“O&M”) Expenses:	
10	• Direct Labor	G-5, Sch. 2
11	• Shared Services	G-5, Sch. 3
12	• Employee & Other Insurance Costs	G-5, Sch. 4
13	• Regulatory Costs and Amortizations	G-5, Sch. 5
14	• Pensions and OPEBs	G-5, Sch. 6
15	• Uncollectible Accounts	G-5, Sch. 7
16	• Environmental Costs	G-5, Sch. 8
17	• Regulatory Commission Expenses	G-5, Sch. 10
18	• Other O&M Costs	G-5, Sch. 11
19	Forecasted Common Plant Expenditures and Additions	G-6, Sch. 3, 4
20	Three-Year Rate Plan	G-7
21	General Inflation Factors	G-10

22

23 **OVERVIEW OF THE RATE INCREASE**

ACCOUNTING PANEL

1 Q. Please describe O&R's current gas rate plan.

2 A. O&R is currently operating under a gas rate plan ("current rate plan") that was
3 adopted by the Commission in its Order Establishing Rates and Terms of
4 Three-Year Rate Plan, issued on October 20, 2006 in Case No. 05-G-1494.

5 This rate plan covers the three-year period from November 1, 2006 to October
6 31, 2009 and prescribes a three-year phased in rate increase. Gas delivery
7 rates were increased \$6.5 million, or 5%, in November 2006; \$6.5 million, or
8 5%, in November 2007 and the third rate year rate increase (*i.e.*, November 1,
9 2008 to October 31, 2009) is for \$1.8 million in addition to a one-time
10 surcharge of \$4.5 million to be collected through the Monthly Gas Adjustment
11 (2.7%).

12 Q. What are the historical test and rate years in this proceeding?

13 A. The historical test year is the twelve months ended June 30, 2008 ("Historical
14 Test Year") and the rate year is the twelve months ending October 31, 2010
15 ("Rate Year" or "RY1").

16 Q. What gas revenue increase is Orange and Rockland seeking in this filing?

17 A. As detailed in the Company's presentation, Orange and Rockland's cost of
18 service substantiates an increase in gas revenues of \$17.8 million for the Rate
19 Year. This increase represents a 3.2% increase to firm full service gas
20 customers and firm transportation customers (assuming an equivalent level of
21 gas supply costs).

22 Q. Please explain what factors are driving the requested increase in rates.

ACCOUNTING PANEL

- 1 A. The first component would be the level of firm sales forecast for the Rate
2 Year. The level of firm sales was projected to be some 2,100 MMcf's lower
3 than the levels currently reflected in rates. This lower sales figure resulted in
4 lower firm revenues of \$3.8 million. The elements impacting the sales and
5 revenue forecast are discussed by the Forecasting Panel. The sales forecast
6 also reflects the impact of lower interruptable benefits of \$1.4 million than
7 currently assumed in rates. The decrease in interruptible benefits is primarily
8 the result of a one time adjustment that was made in Case 05-G-1494 to
9 increase the imputation target in order to compensate for costs not included in
10 the revenue requirement calculation. The interruptible imputation adjustment
11 is discussed in the testimony of the Rate Panel.
- 12 Overall the level of other operating revenues is forecast to be unchanged. The
13 loss of non-recurring transitional accounting credits that resulted when
14 utilities were shifted from a revenue based tax to the NYS Corporate Business
15 Tax starting in 2000 of almost \$0.7 million per year has been offset by higher
16 other operating revenues for purchase of receivables ("POR") and other
17 services.
- 18 Q. Please describe the factors other than lower revenues driving O&R's proposed
19 rate increase request.
- 20 A. As discussed in the testimony of Company witness DiLoreto, the Company is
21 requesting funding for several new / expanded operating programs and to
22 establish a contingency fund for unforeseen events. The cost of these
23 programs excluding his requested staffing increases amounts to \$1.5 million.

ACCOUNTING PANEL

1 Salary and wages are projected to increase by \$1.9 million; pensions and other
2 post employment benefit costs (“OPEBs) by \$1.1 million; and, employee
3 benefit and other insurance by \$0.4 million.

4 Q. Please continue.

5 A. The increase in depreciation expense associated with new plant of \$1.3 million
6 is partially offset by depreciation rate changes proposed by Mr. Hutcheson for
7 general plant of \$0.5 million, or a net increase of \$0.8 million. We would note
8 the changes proposed by Mr. Hutcheson for common general plant would also
9 reduce costs allocated to electric operations, and if approved, we would
10 propose to defer the savings for the benefit of electric customers until their
11 disposition can be addressed in the Company’s next electric base rate
12 proceeding.

13 Property and other taxes are projected to increase by \$1.0 million. While this
14 filing reflects the expiration of the passback of tax refunds contained in Case
15 05-G-1494, it also includes a proposal to pass back refunds received during the
16 interim period, as well as an estimated over-collection that will result from the
17 current true-up mechanism in place for property taxes.

18 The carrying cost of new infrastructure investments at the Company’s
19 currently authorized cost of capital is \$1.2 million and the revenue requirement
20 associated with an 11.6% return on equity requested for a multi-year filing
21 accounts for \$5.3 million of the requested rate increase.

22 Finally, flow thru tax benefits resulting from increased projections of Medicare
23 Part D tax benefits and the lower NYS Corporate tax rate of 7.1%, as

ACCOUNTING PANEL

1 compared to 7.5% in effect at the time rate were established in Case 05-G-
2 1494, reduce the requested increase by \$0.6 million.

3

4 **HISTORICAL FINANCIAL STATEMENTS**

5 Q. Is the Accounting Panel familiar with the books and records of the Company?

6 A. Yes.

7 Q. Are the accounts of the Company kept in accordance with the Uniform System
8 of Accounts prescribed by the Commission?

9 A. Yes.

10 Q. Please describe Exhibit G-1 and each of the supporting schedules.

11 A. Exhibit G-1 is entitled "Historical Financial Data - Gas" and includes ten
12 supporting schedules.

13 • Schedules 1 through 5 are balance sheets and supporting schedules as of
14 December 31, 2004, 2005, 2006, 2007 and June 30, 2008.

15 • Schedules 6 through 10 are income statements and supporting schedules
16 for the 12 months ended December 31, 2005, 2006, 2007 and June 30,
17 2008.

18 The data on these schedules has been taken directly from the books of the
19 Company except for the average gas plant per customer on Schedule 5 and the
20 unit cost figures on Schedules 8 and 10, which have been computed for the
21 purpose of the respective exhibits. It should be noted that Schedules 1, 2, 4
22 and 6 reflect total Company operations.

ACCOUNTING PANEL

- 1 • Schedule 1 shows comparative balance sheets at December 31, 2004, 2005,
2 2006, 2007 and June 30, 2008.
- 3 • Schedule 2 is a statement of retained earnings at December 31, 2004, 2005,
4 2006, 2007 and June 30, 2008.
- 5 • Schedule 3 shows the net book value of gas plant in service by primary
6 account at December 31, 2004, 2005, 2006, 2007 and June 30, 2008.
- 7 • Schedule 4 shows the net book value of common plant in service at
8 December 31, 2004, 2005, 2006, 2007 and June 30, 2008.
- 9 • Schedule 5 shows gas plant in service and the average cost per customer at
10 December 31, 2004, 2005, 2006, 2007 and June 30, 2008.
- 11 • Schedule 6 shows comparative income statements for the 12 months ended
12 December 31, 2005, 2006, 2007 and June 30, 2008.
- 13 • Schedule 7 is a statement of gas operation and maintenance expenses for
14 the years ended December 31, 2005, 2006, 2007 and the 12 months ended
15 June 30, 2008.
- 16 • Schedule 8 shows gas operating expenses per Mcf sold for the 12 months
17 ended December 31, 2005, 2006, 2007 and June 30, 2008.
- 18 • Schedule 9 is a statement of gas operating taxes, other than income taxes,
19 for the 12 months ended December 31, 2005, 2006, 2007 and June 30,
20 2008.
- 21 • Schedule 10 is a statement of gas operating revenues per Mcf of gas sold
22 for the years ended December 31, 2005, 2006, 2007 and the 12 months
23 ended June 30, 2008.

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1

2

COST ALLOCATION PROCEDURES

3 Q. Please describe the cost allocation procedures currently utilized by Orange and
4 Rockland to assign costs to its utility subsidiaries.

5 A. Orange and Rockland and its utility subsidiaries Pike, which provides utility
6 service in Pennsylvania, and RECO, which provides utility service in New
7 Jersey, operate as one integrated organization. It is the Company's policy to
8 charge costs for labor, material and services directly to the responsible
9 jurisdiction (*i.e.*, Orange and Rockland, Pike, or RECO) to the extent practical,
10 through the use of time sheet reporting and company specific account numbers.
11 In those instances where work performed is for the common benefit of two or
12 more jurisdictions, then costs would be allocated through the use of common
13 expense clearing accounts. Different studies are used to develop the bases for
14 allocating costs ranging from building service and data processing costs to
15 payroll for administrative areas such as Legal or Accounting.

16 Q. Does the Company use different procedures to allocate costs between its utility
17 subsidiaries and its New York electric and gas operations?

18 A. Yes, historically cost allocations among Orange and Rockland, RECO, and
19 Pike for electric and gas operation and maintenance costs, customer expenses,
20 administrative and general expenses and carrying costs on the Company's net
21 utility plant investment have been allocated pursuant to existing contractual
22 agreements. In New York, the Commission has jurisdiction over the
23 methodology followed by the Company to allocate common costs related to

ACCOUNTING PANEL

1 New York electric and gas operations. Over time, procedures were developed
2 to allocate costs based on a formula that factors in utility plant investment,
3 operation and maintenance expenses, and payroll expenses.

4 Q. Did the Company follow the existing procedures to allocate common costs in
5 this proceeding?

6 A. Yes. The Company used the allocation percentages for common electric and
7 gas costs for New York operations as approved by the Commission in Case 99-
8 G-1695 (and reconfirmed by the Commission in Case 02-G-1553 and Case 05-
9 G-1494).

10

11 **AVERAGE GAS RATE BASE**

12 Q. Please explain how the rate base for the forecast year was developed.

13 A. The Summary Schedule of Exhibit G-2 details the Company's average rate
14 base for the Historical Test Year per books and also shows the Rate Year.

15 Q. What components have you included in rate base?

16 A. We included in gas rate base the twelve-month average balance of gas plant in
17 service, gas plant for future use, the allocated portion of common utility plant,
18 and that portion of construction work in progress not subject to an Allowance
19 for Funds Used During Construction. We deducted the accumulated provision
20 for depreciation relating to gas plant in service, gas plant held for future use,
21 and the allocated portion of common utility plant as well as the average
22 balances related to customer advances for construction, accumulated deferred
23 income taxes and accumulated deferred investment tax credits. Finally, we

ACCOUNTING PANEL

1 added working capital, and reflected the twelve-month average balance of
2 regulatory assets and liabilities.

3 The projected balances in the plant accounts have been derived from the
4 construction forecast. Exhibit G-2, Schedules 2 through 4 include the major
5 plant additions shown on Exhibit G-6, Schedules 2 and 4. The forecast for gas
6 plant held for future use assumes no change in that component of rate base
7 beyond June 30, 2008. The forecast of the various components of the
8 accumulated reserve for depreciation through October 31, 2010 utilizes the
9 plant-in-service forecast and the rates used for depreciation of various plant
10 components as of June 30, 2008. The forecast of the accumulated reserve for
11 depreciation for the Rate Year utilizes the proposed depreciation rates
12 addressed in the testimony of Company witness Hutcheson.

13 The forecasts of accumulated deferred income taxes and accumulated deferred
14 investment tax credits have been derived from the forecast of plant-in-service
15 using the appropriate book and tax depreciation factors. Data supporting the
16 monthly plant in service and accumulated depreciation balances are shown on
17 Exhibit G-2, Schedules 3 and 4, respectively.

18 The forecast of working capital requirements for cash working capital,
19 prepayments and materials and supplies are summarized on Exhibit G-2,
20 Schedule 5. The cash working capital is derived by first deducting purchased
21 gas costs, uncollectible and regulatory costs and amortizations from the annual
22 O&M expenses shown on Exhibit G-5, Summary. The cash working capital is
23 then calculated by use of the FERC one-eighth formula.

ACCOUNTING PANEL

1 The prepayment balances were forecast based on the estimated cost of the
2 underlying cost element or the usage of general inflation factors. For example,
3 prepaid property taxes, which are the single largest prepayment, are forecasted
4 based on the projected property tax bills. The forecast of insurance premiums
5 was based on the Historical Test Year plus general inflation. The forecasted
6 balances of materials and supplies include plant materials and stores expense.
7 Plant materials and stores expense was forecasted by use of the general
8 inflation factors addressed later in our testimony.

9 Q. Have you prepared an exhibit that compares the Company's average rate base
10 with its earnings base?

11 A. Yes. Exhibit G-2, Schedule 9, makes this comparison.

12 Q. What is the purpose of this schedule?

13 A. The NYPSC adopted the earnings base/capitalization comparison so that a
14 return is authorized on investor-supplied capital only. The adjustment
15 originated, in part, because of concerns that the standard working capital
16 allowance formula (*i.e.*, the "one-eighth formula") did not accurately measure
17 the working capital devoted to the provision of utility service. The comparison
18 is used to develop what is known as the earnings base, or the capital devoted to
19 providing utility services.

20 Q. What does the schedule show?

21 A. Exhibit G-2, Schedule 9, shows the average rate base and capitalization for the
22 twelve-month period ended June 30, 2008 for electric and gas operations. The
23 Company's average capitalization balance was developed by first calculating

ACCOUNTING PANEL

1 O&R's average equity and long-term debt balances for the twelve-month
2 period ended June 30, 2008. This figure was then increased for other funds
3 that are available to support rate base and reduced by amounts of capitalization
4 that are not devoted to the maintenance of rate base.

5 Q. Has the methodology you have just described been used in prior Orange and
6 Rockland proceedings?

7 A. Yes.

8 Q. Is there a difference between capitalization and average rate base for the
9 Historical Test Year and, if so, what does this require?

10 A. Yes, there is a difference. Rate base exceeds capitalization, and the amount of
11 this excess that is attributable to gas operations is \$12,183,000. Given the
12 nature and purpose of the comparison, Rate Year rate base for gas operations
13 must be decreased by this amount. This adjustment has been reflected in rate
14 base on Exhibit G-4, Schedule 2, Page 1, and in the calculation of the revenue
15 requirement on Page 2.

16

17 **GAS INCOME STATEMENT AND RATE OF RETURN**

18 Q. Please generally describe how the Company's forecast cost of service was
19 developed.

20 A. Please refer to Exhibit G-4, Schedule 2, Page 1, which is the summary of the
21 Historical Test Year and Rate Year cost of service. Column 1 of this schedule
22 contains the actual per books numbers for the Historical Test Year. Operating
23 revenues have been detailed by sales to the public, sales for resale, and other

ACCOUNTING PANEL

1 operating revenues. The operating expenses have been broken down into
2 elements of cost, some of which are forecasted directly and others of which are
3 included in a grouping that was escalated by inflation rates supported later in
4 our testimony. The Historical Test Year contains items not specifically related
5 to actual historical year operations or which may be considered non-recurring.
6 These items are adjusted through various normalizing adjustments as set forth
7 in column 3 of the Historical Test Year and on Schedule 7 of the Exhibit. The
8 adjusted Historical Test Year results are summarized in column 4. Column 6
9 reflects conditions in the Rate Year and various rate case adjustments and
10 column 7 reflects the Rate Year absent rate relief of \$17,773,000, which is
11 shown in column 8. Column 9, which is a summation of columns 7 and 8,
12 shows operating income, average rate base and rate of return for the Rate Year
13 after factoring in the rate increase.

14 Q. Was the data shown for the Rate Year derived from the per books data shown
15 in the first column?

16 A. Yes, it was. Each element of cost has been analyzed to further subdivide the
17 basic elements into necessary components for purposes of forecasting the
18 various changes in that cost element for the three forecast periods. Exhibit G-
19 4, Schedules 3 through 8 support the remaining cost of service components:
20 other operating revenues, depreciation, taxes other than income taxes, and state
21 and federal income taxes, respectively.

22 Q. Please address the \$17,773,000 amount labeled "Proposed Rate Increase" on
23 Exhibit G-4, Schedule 2, Page 1.

ACCOUNTING PANEL

1 A. The \$17,773,000 Proposed Rate Increase reflects the increase in revenue
2 necessary to achieve an overall rate of return of 9.48%, which reflects Orange
3 and Rockland's cost of capital. The calculation of the revenue increase is
4 shown on Exhibit G-4, Schedule 2, Page 2. The calculation applies the 9.48%
5 rate of return to the projected gas rate base of \$261,760,000 to determine the
6 required level of return of \$24,813,000. This amount is compared to the
7 projected Rate Year return of \$14,183,000 to derive the additional required
8 return of \$10,630,000. The appropriate revenue tax, late payment charge,
9 uncollectible accounts and income tax expense factors are applied to calculate
10 the \$17,773,000 required increase in revenue.

11 **Other Operating Revenues**

12 Q. How was the forecast of Other Operating Revenues on Exhibit G-4, Schedule
13 3 developed?

14 A. The schedule shows five components for other operating revenues, *i.e.*,
15 Miscellaneous Service Revenues, Power Generation, MFC / GSC / MGA –
16 Unbundled revenues, Joint Use Rents, and Revenue Subject to Refund.

17 Q. Please discuss Miscellaneous Service Revenues.

18 A. The first item within Miscellaneous Service Revenues, Late Payment Charge
19 Revenues, was forecasted by calculating the ratio of actual late payment
20 charges to actual sales revenues and applying this factor to the Rate Year sales
21 revenues forecast. The next item, Billing and Payment Processing is part of the
22 sales revenue forecast, and is reflected on Schedule 1. The Phase-In of Gas
23 Rate Relief reflects the accounting related to the phased-in rate increase

ACCOUNTING PANEL

1 pursuant to the current gas rate plan, which will not be necessary in the Rate
2 Year. The next item POR revenues represents the discounting of Marketer
3 receivables purchased and billed by the Company. In essence, the Company
4 buys the receivable from the Marketer at a discount and assumes the credit risk
5 for collecting the bill on the behalf of the Marketer. These revenue will vary
6 directly with the cost of purchased gas (*i.e.*, as the cost of gas rises so will the
7 revenues and billing amounts at risk). This item was projected by taking the
8 historical level of POR revenues as a percentage of historical firm revenue and
9 applying this factor to the forecast revenues. Marketer Billing Services were
10 held constant as they are dependent on the number of customers on the retail
11 access program. The Company is not forecasting any net change in the
12 number of customers participating in retail access. Gas Service Revenues
13 includes reconnects, accommodation work, access fines, and shared meter
14 assessments. These were forecast based on a three-year historic average.
15 Access fines for the 12 months ended 6/30/06, 6/30/07 and 6/30/08 were
16 \$158,000, \$159,000 and \$40,000, respectively. The amount for the 12 months
17 ended 6/30/08 is considered abnormal. Therefore the Company first
18 normalized these revenues and then took the three-year average. This is the
19 primary reason that the Company's forecast for Gas Service Revenues is
20 \$159,000, or \$133,000 higher than the historic period of \$26,000. The
21 forecasts for Sales of M&S Stock (*i.e.*, materials and supplies) and for
22 revenues from Bad Check Charges were based on the three-year historic
23 averages. The last two items Amortization of NYS Tax Rate Change and Gas

ACCOUNTING PANEL

1 Hedging Program – Interest were small decreases to revenue that we
2 eliminated from the Rate Year.

3 Q. Please explain the Power Generation Service Revenues.

4 A. Part of the Company's current non-firm revenue imputation includes \$650,000
5 annually for the transportation of gas to power generation facilities. The
6 majority of these revenues are derived from gas delivered to Mirant's Bowline
7 Plant. These revenues are fully reconciled and any variation between actual
8 and forecast are flowed back / collected from all full service customers. While
9 the Company collected almost \$1.4 million of revenue in the Test Year, there
10 is no basis to assume that this level will continue, since Mirant constructed its
11 own pipeline and could at some point in the future decide to utilize it.

12 Q. Please continue with MFC / GSC / MGA – Unbundled revenues.

13 A. We normalized these items which are either part of the sales revenue forecast
14 or are billed to customers through various other riders that do not effect the
15 revenue requirement.

16 Q. Please continue with Joint Use Rents.

17 A. Joint Use Rents with the Company's subsidiaries, RECO and Pike, is projected
18 at \$351,000 based on a study prepared in September 2008.

19 Q. What are the items in the next group, Revenue Subject to Refund?

20 A. The first item reflects the 2007 penalty resulting from customer service
21 surveys. The next two line items reflect the Company's proposal to refund to
22 customers the 2006 and 2007 customer performance penalties. The next three
23 items reflect refunds to customers approved in the current rate plan. These

ACCOUNTING PANEL

1 refunds will end at October 31, 2009. The final item, 2007 Penalties for Line
2 Losses is associated with Purchased Gas Costs and will be passed back to
3 customers through the Gas Supply Charge ("GSC") starting in January 2009.

4 **Depreciation**

5 Q. Please describe Schedule 4.

6 A. Schedule 4 contains three pages; the first page shows the monthly calculation
7 of depreciation expense for gas and common plant for the period from July 1,
8 2008 through October 31, 2009. The second page shows the monthly
9 calculation of depreciation expense for gas and common plant for the Rate
10 Year at existing depreciation rates. The third page shows the monthly
11 calculation of depreciation expense for gas and common plant for the Rate
12 Year at the depreciation rates proposed by Company witness Hutcheson.

13 **Taxes Other Than Income Taxes**

14 Q. Please describe the development of Taxes Other than Income Taxes.

15 A. Exhibit G-4, Schedule 5, presents gas taxes other than income taxes for the
16 twelve months ended June 30, 2008 and for the Rate Year. Taxes other than
17 income taxes include property taxes, payroll taxes, revenue taxes, and other
18 taxes.

19 Payroll taxes were determined by applying effective payroll tax rates to the
20 forecasted direct labor expense. Revenue taxes were determined based on the
21 estimated revenue multiplied by the current tax rates. Other miscellaneous
22 taxes were escalated by the inflation rates to arrive at the Rate Year level of tax
23 expense.

ACCOUNTING PANEL

1 Q. Please describe the method used to forecast property taxes.

2 A. The property taxes associated with gas operations were provided by Company
3 witness Hutcheson and were derived by taking the latest known property tax
4 bills and increasing those amounts based on a five-year average of actual tax
5 bill increases experienced by the Company. The projected increase was
6 apportioned over the appropriate tax fiscal year to determine the projected
7 property tax expense in the Rate Year. The Company's current gas rate plan
8 provides for a reconciliation of property tax expenses. Property taxes have
9 been lower than the target established in the current rate plan to date. However,
10 the most recent school tax bills are higher than the targets. The Company
11 projects that by the end of the current rate plan the deferred balance will be
12 approximately \$720,000. Our proposal to refund this amount over three years
13 is reflected on Schedule 4. Upon the effective date of new rates, O&R
14 proposes to continue the true up of the projected property tax expenses by
15 deferring the difference between the actual property tax expense and the
16 amount allowed in rates in this case. A true up is appropriate to ensure that
17 customers pay no more and no less than the actual property tax expenses
18 incurred by the Company.

19 Q. What do the property tax refund amounts on Exhibit G-4, Schedule 5,
20 represent?

21 A. The property tax refunds in the Historical Test Year represent amortizations of
22 previously deferred refunds due customers from the Town of Ramapo pursuant
23 to the current rate agreement ending October 31, 2009. The refund in the Rate

ACCOUNTING PANEL

1 Year represents a passback of new refunds that the Company proposes to
2 amortize over the three rate years ending October 31, 2012.

3 Q. Please address the property tax refund retention incentive previously approved
4 by the NYPSC for O&R.

5 A. A. Under its current gas rate plan, O&R is allowed to retain 14% of
6 property tax refunds. O&R proposes that the mechanism for O&R to share in
7 property tax refunds, including refunds in the form of credits against tax
8 payments (after deducting incremental expenses associated with achieving the
9 refund) be continued.

10 **Income Taxes**

11 Q. Please describe how the calculation of State and Federal income tax expenses
12 were performed for gas operations.

13 A. We will begin with the computation of State income tax, which is shown on
14 Schedule 6 of Exhibit G-4. Starting with operating income before state income
15 taxes ("SIT") for the twelve months ended June 30, 2008 and the various
16 columns for normalizing adjustments and rate case adjustments, we then show
17 the various required tax adjustments to book operating income to determine
18 taxable income. We then computed the amount of State income tax payable
19 using the statutory rate of 7.1% applicable to such taxable income. The items
20 detailed as normalizing and rate case adjustments are more fully described on
21 Schedule 9 of this exhibit. The amount included in the column Proposed Rate
22 Increase represents the additional New York State income tax to be paid as a

ACCOUNTING PANEL

1 result of the additional revenue requirement. The last column represents the
2 State income tax for the Rate Year.

3 Q. Please explain Schedule 7.

4 A. Schedule 7 details the Federal income tax ("FIT") computation. Starting with
5 operating income before Federal income taxes for the twelve months ended
6 June 30, 2008 and the columns for normalizing adjustments and rate case
7 adjustments, we deducted the amount of New York State income tax
8 previously determined on Schedule 5 to arrive at book operating income before
9 FIT. We then show the various required tax adjustments to book operating
10 income to determine taxable income and computed the amount of Federal
11 income tax payable using the statutory rate of 35% applicable to such taxable
12 income. From this payable amount we then reflected certain items as
13 adjustments to taxable income as well as amortizations for items normalized in
14 the rate year or in prior periods to arrive at Federal income tax expense. The
15 items detailed as normalizing and rate case adjustments are more fully
16 described in Schedule 9 of this exhibit. The amount included in the column
17 Proposed Rate Increase represents the additional Federal income tax to be paid
18 as a result of the additional revenue requirement.

19 Q. Please describe Exhibit G-4, Schedule 10.

20 A. Exhibit G-4, Schedule 10, presents a statement of sources and application of
21 funds for the twelve months ending October 31, 2010 for Orange and
22 Rockland's Gas Operations. Sources of Funds are broken down into Internal
23 and External Sources. Internal Sources include the change in retained earnings

ACCOUNTING PANEL

1 during the twelve months ending October 31, 2010, depreciation,
2 amortizations, deferred taxes and an appropriate deduction for AFUDC.
3 External Sources include long-term and short-term debt, and common stock
4 equity. The primary use of funds is for construction and the retirement of
5 short-term debt.

6

7 **OPERATION AND MAINTENANCE EXPENSES**

8 **Direct Labor**

9 Q. Please describe Exhibit G-5, Schedule 2.

10 A. Exhibit G-5, Schedule 2, Gas Operating Expenses – Direct Labor, is a two-
11 page exhibit that identifies the historic O&R consolidated labor costs for the
12 Historical Test Year and calculates the projected labor costs through linking
13 periods and ultimately for the Rate Year, twelve months ending October 31,
14 2011 (“Rate Year 2” or “RY2”) and twelve months ending October 31, 2012
15 (“Rate Year 3” or “RY3”). Page 1 of the Exhibit identifies the amount of total
16 labor charged to the O&R Gas Department (as derived on Page 2) as to each
17 account guideline classification (*e.g.*, gas production and purchase expense,
18 other gas supply expense, and gas distribution expense). Page 2 of the Exhibit
19 identifies labor costs according to employee classification, that is, weekly paid
20 employees and monthly paid employees and further identifies the same
21 consolidated labor costs by functional cost distribution (*e.g.*, electric expense,
22 gas expense, construction).

ACCOUNTING PANEL

1 Q. Please describe how you projected gas direct labor expense for the Rate Year
2 as shown on Exhibit G-5, Schedule 2, Page 1 of 2?

3 A. We began by detailing the historic labor costs for the Historical Test Year
4 according to the classifications specified above. We then calculated any
5 normalizing adjustments applicable to the Historical Test Year in order to
6 derive total normalized labor costs. Using the normalized Historical Test Year
7 data as a starting point, we then escalated those costs through the end of the
8 Rate Year, including the labor costs associated with any program changes
9 anticipated between the end of the Historical Test Year and the end of the Rate
10 Year. The result is the expected total consolidated labor costs for the Rate
11 Year.

12 Q. Please describe the normalizing adjustments to the Historical Test Year labor
13 expense in your calculations.

14 A. The only normalizing adjustment is the elimination of the cost of the Officer
15 ATIP from the Historical Test Year, which amounted to a reduction of
16 \$163,365 in labor charged to gas O&M expense.

17 Q. What type of costs are included under the heading Program Changes on
18 Exhibit G-5, Schedule 2?

19 A. Program Changes include the cost of additional employees to be added
20 between the end of the Historical Test Year and the end of the proposed Rate
21 Year 3 in this proceeding, that is, October 31, 2012. The additional employees
22 fall into two broad categories, as follows: Eight employee positions that were
23 approved in the last O&R electric base rate case, Case 07-E-0949, the cost of

ACCOUNTING PANEL

1 whom will be allocated, in part, to O&R gas operation and maintenance
2 expense. A listing of these employee positions is provided as Attachment A to
3 this testimony; and twenty eight new employees presented in the context of
4 programs and initiatives in this case. Details regarding the twenty eight
5 additional employees are shown in Attachment B.

6 Q. Please provide the rationale for the addition of the 28 employees that are added
7 in this case.

8 A. Company witness Kennedy will provide details regarding the position of Gas
9 Marketing Specialist. Company witness Diloreto will provide details
10 regarding all other positions except that of Gas Safety Specialist, which we
11 will address.

12 Q. Please continue with support for the position of Gas Safety Specialist.

13 A. Gas safety inspections and all other gas safety matters are currently
14 administered by the Safety Department. However, many gas safety issues and
15 regulations are unique and are sufficiently different from general safety and
16 from electric safety issues that the Company feels that it is imperative that a
17 Gas Safety Specialist position must be added. Among the primary
18 responsibilities of the Gas Safety Specialist would be the inspection of both
19 contractor and Company field operations work sites so that they comply with
20 OSHA regulations and Company procedures, and to evaluate whether existing
21 safety policies and procedures are adequate. This position also would be
22 responsible for public safety and education programs aimed at educating the
23 general public, public safety personnel such as fire and police departments,

ACCOUNTING PANEL

1 business associations, contractor safety associations, and others about the
2 hazards associated with consumer gas use and the Company's gas transmission
3 and distribution facilities. Other specific responsibilities of this position
4 include administration of the Gas Contractor Drug and Alcohol Compliance
5 Program, administration and coordination of the Company's DriveCam
6 Program, which is a driver safety training device, updating and expanding the
7 Company's Safety Guidelines as they relate specifically to gas operations, and
8 attend, in an instructional capacity, all Gas Operations Department
9 communications meetings to insure the understanding of, and compliance with,
10 gas safety regulations. A complete list of the duties and responsibilities of this
11 new Gas Safety Specialist position is included at the end of this testimony as
12 Attachment C.

13 Q. Please describe the labor escalation factors used in your calculations.

14 A. The labor escalation for weekly paid employees, including escalation
15 applicable to program changes, was calculated for all periods at 3.50%, except
16 for the Rate Year when the rate was reduced to 2.50%. The rate of 3.50% is
17 the actual wage increase awarded to the Company's bargaining unit employees
18 on June 1, 2008 pursuant to the negotiated labor agreement with Local 503 of
19 the International Brotherhood of Electric Workers, which represents the O&R
20 bargaining unit employees. This five-year agreement became effective on
21 June 1, 2004 and expires on June 1, 2009. Absent a negotiated wage increase
22 to become effective on June 1, 2009 and thereafter, the last actual wage

ACCOUNTING PANEL

1 increase of 3.50% was used in this case. The 2.50% rate used for the Rate
2 Year reflects a productivity adjustment of 1.00%.

3 Q. Please describe how you establish merit increases for management employees.

4 A. For management employees, we benchmarked merit increases with other
5 utility companies who were willing to share compensation information with us.

6 We also used compensation surveys published by various compensation
7 consulting and research firms, such as Hewitt Associates, Watson Wyatt, the
8 Conference Board, World at Work, ORC World Wide, Edwin Perlin

9 Associates and Mercer. The information included for Edward Perlin
10 Associates and Hewitt Associates is based on a telephone survey conducted by

11 the Company. From this information, we establish the merit budget and salary

12 structure adjustment for base salaries for the year. We generally select rates

13 that reflect no more than the average of the benchmarked companies. For

14 2007, for example, the merit increase, based on this information, was 3.7

15 percent.

16 The labor escalation for the monthly paid employees, including escalation

17 applicable to program changes, was calculated for all periods at 3.60% except

18 for the Rate Year when the rate was reduced to 2.60%. As with the weekly

19 paid employee wage increase, the monthly rate was reduced by a 1.00%

20 productivity factor for the Rate Year.

21 Q. Does management compensation also include an annual incentive component?

22 A. Yes. Management compensation consists of two basic elements: base pay (as
23 described above) and annual incentives, both of which are included in direct

ACCOUNTING PANEL

1 labor expense set forth in Exhibit G-5, Schedule 2. Annual incentive
2 compensation is based on the overall achievement of the Company's annual
3 corporate and departmental goals. Awards are based on actual performance
4 relative to its pre-specified goals.

5 Q. On which items did the Company reflect a productivity adjustment in this
6 filing?

7 A. Consistent with the adjustment reflected in O&R's recently approved electric
8 rate plan in Case 07-E-0949, the Company imputed a one percent reduction of
9 its forecast payroll, employee benefit insurance, pensions, OPEBs and payroll
10 tax forecast for the Rate Year.

11 Q. In addition to implementing a 1% productivity adjustment in this filing, how
12 has the Company achieved productivity savings for customers over time?

13 A. The Company has been successful in implementing programs that have
14 resulted in savings in many areas over the past several years. The programs
15 and initiatives that have resulted in these gains are evident throughout the
16 Company, but are particularly noteworthy in the areas of containing the growth
17 in employee benefit costs, in the work practices and system improvements in
18 the gas operations area, and in the management of the Company's property
19 taxes. For example, as described in this testimony, some of the initiatives that
20 have impacted cost savings in the area of employee benefits include merging
21 of the Company's health care, prescription drug, dental, and vision plans into
22 the same providers used by other CEI affiliates in order to reduce
23 administrative costs and to realize the benefits of being part of a much larger

ACCOUNTING PANEL

1 group. In addition, savings have resulted from changing plan administrators,
2 increasing deductibles and co-insurance amounts, and changing plan funding
3 to self-insurance where appropriate.

4 Also, as more fully described in the testimony of Company witness Diloreto,
5 the Gas Operations Department has implemented a gas mobile dispatch
6 system, has initiated a four-year lock in period for Company gas locators,
7 thereby reducing costly turnover, and has initiated additional shifts in
8 appropriate areas for both union and non-union positions. Moreover, the
9 Company has implemented the NUCON system, which is a new construction
10 job tracking system that provides enhanced interfacing with operations and the
11 Company's work management system. The testimony of Company witness
12 Hutcheson details initiatives and procedures that are in place to review and
13 contest property tax assessments and the successful efforts to reduce
14 assessments in the towns of Clarkstown, Haverstraw, Ramapo, and
15 Orangetown. Similar claims are pending in the towns of Monroe and
16 Middletown

17 Q. What is the Company's position regarding updating the wage increase data
18 provided in this proceeding for actual wage changes and for costs associated
19 with other labor related items that become effective before this case is
20 finalized?

21 A. The Company advocates updating wage increases and other labor related
22 items. Wage increases applicable to monthly paid employees are effective
23 annually on April 1, with the next wage increase anticipated for April 1, 2009.

ACCOUNTING PANEL

1 Wage increases applicable to weekly paid employees are effective annually on
2 June 1, with the next wage increase anticipated for June 1, 2009. Since the
3 current labor agreement with the Company's weekly paid employees expires
4 on June 1, 2009, the next wage increase for weekly paid employees will be the
5 result of the negotiated labor agreement between the Company and the Local
6 503 of the International Brotherhood of Electrical Workers, which will become
7 effective on June 1, 2009. Since the 2009 wage increases for both the monthly
8 and weekly paid employees and any other negotiated labor related changes will
9 become effective before the conclusion of this case, the Company advocates
10 updating this case for such items.

11 **Shared Services**

12 Q. Please explain the Shared Services cost element shown on Exhibit G-5,
13 Schedule 3.

14 A. The shared services cost element reflects the allocation of costs from Con
15 Edison and Consolidated Edison, Inc. ("CEI") for administrative and general
16 services provided to Orange and Rockland such as accounting, treasury, and
17 tax services. These costs are detailed into labor, fringes and other cost
18 components.

19 Q. What is the basis for the billing of shared services to O&R?

20 A. O&R is billed a share of the total costs of operating the various departments
21 which provide services to the Company. These costs include labor, fringes and
22 other expenses. In addition, the Company is billed for 100% of other services

ACCOUNTING PANEL

1 provided solely on its behalf by Con Edison. These charges are then allocated
2 to gas operations by use of the common expense allocations.

3 Q. How did you determine the Rate Year shared service expense of \$4,123,000?

4 A. We started with the actual shared services expense of \$3,842,000 for the
5 twelve months ended June 30, 2008. We then escalated the labor component
6 of the shared service billing by 7.14%, the fringes by 18.70%, and the other
7 components of the billing by the general inflation factor of 5.3% to arrive at
8 the Rate Year expense of \$4,123,000. The labor and fringe benefit factors
9 used in this calculation are the same factors used to project O&R labor and
10 employee welfare expense cost increases.

11 **Employee and Other Insurance Costs**

12 Q. Please describe the costs included in the item "Health and Life Insurance
13 Costs" set forth on Exhibit G-5, Schedule 4, page 2.

14 A. The first line item on this exhibit includes all costs related to medical, dental,
15 prescription drugs (card and mail order), vision, health maintenance
16 organizations ("HMOs"), life insurance, disability, and accidental death and
17 dismemberment coverage. The amounts are net of reimbursements pursuant to
18 the Consolidated Omnibus Budget Reconciliation Act of 1985 ("COBRA"),
19 employee and retiree contributions, capitalized, and recovered amounts.

20 Q. How does the Company administer its medical benefit plans?

21 A. The Company's hourly employees are covered under a fully insured Point of
22 Service Plan ("POS") with Aetna US Healthcare ("Aetna"), for which pre-
23 established premium rates are paid. A self-funded POS Plan administered by

ACCOUNTING PANEL

1 United Healthcare covers the majority of management employees. In addition
2 to the self-insured plan, management employees are offered the option of
3 enrolling in one of two HMOs. For retirees, the most prevalent coverage is an
4 indemnity type plan administered by United Healthcare.

5 Q. How does the Company manage its prescription, dental and vision insurance
6 costs?

7 A. Prescription, dental and vision benefits for employees have been carved out of
8 the medical plans and are administered by Caremark, MetLife, and
9 Comprehensive Professional Systems, respectively. Coverage for employees
10 is provided through self-insured indemnity type plans. Each year the Company
11 reviews industry trends with regards to sharing of cost increases for
12 prescription drug, dental and vision plans. These trends are taken into
13 consideration as well as plan design and employee contribution changes.

14 Q. What changes has the Company made within the benefit plans over the last
15 several years?

16 A. Since the merger with Con Edison, Orange and Rockland has moved its health
17 care, prescription drug, dental and vision plans over to the same health care
18 providers used by its Con Edison affiliates. This move has allowed the
19 Company to realize lower administrative fees and the benefits of being part of
20 a much larger group. Medical coverage for all hourly employees is currently
21 with a fully insured POS. Management and retired employees are covered
22 under the self-insured plan administered by United Healthcare.

23 Q. How else has the Company been aggressive in controlling healthcare costs?

ACCOUNTING PANEL

1 A. The Company has made several modifications to its health care benefits to
2 control the growth of costs. For example, administrators have been changed,
3 deductibles and co-insurance amounts and employee contributions have been
4 increased. Funding has been changed to self-insurance, where and when
5 appropriate.

6 Q. Have all of these changes been effective in the control of costs?

7 A. Yes. The Company has focused its management on the problem of spiraling
8 health insurance costs. The Company has made several difficult business
9 decisions and introduced innovative plan design features, which have resulted
10 in lower health care cost increases. With employee contributions for example,
11 the cost borne by employees is moving towards 20% of the premiums paid for
12 both union and management active employees. The move towards higher
13 employee contributions has helped to keep the overall level of cost increases
14 experienced by the Company in line with medical trend rates.

15 Q. How were your projections of health and life insurance costs derived?

16 A. We escalated the actual charges using an overall factor of 17.2%, which
17 represents the cumulative cost increase the Company expects over the 28
18 month period from July 2008 – October 2010.

19 Q. Certain of the Company's medical costs also relate to retirees, such as health
20 and life insurance, prescription drug costs, and Medicare Part B payments.

21 Are these costs also included on Exhibit G-5, Schedule 6?

ACCOUNTING PANEL

1 A. Exhibit G-5, Schedule 4 contains the pay-as-you-go cost for retiree claim
2 payments made by the Company, net of reimbursements from the VEBA
3 Benefit Trusts. Exhibit G-5, Schedule 6, excludes all of these payments.

4 Q. Please explain how reimbursements from employees and retirees are reflected
5 in Exhibit G-5, Schedule 4?

6 A. Exhibit G-5, Schedule 4 includes adjustments to reduce the total medical costs
7 for reimbursements by employees, retirees and surviving spouses. The
8 Company makes several life and health insurance programs available to
9 employees, and retirees, their dependents, and spouses of deceased employees
10 and retirees, in which the individual makes payment of the insurance premium.
11 Spouses of some deceased employees and all retirees are offered optional
12 continuation of benefits, for which they are billed a premium. Also included in
13 this category are contributions made by employees and retirees for health
14 coverage. For both hourly and management employees, the contribution
15 amount is based upon the coverage elected (*i.e.*, employee only, employee plus
16 one dependent, employee plus two or more dependents) and the provisions of
17 the Company's current Bargaining Unit Contract. For retirees, the amount is
18 "frozen" at the rate they were paying at the time of their retirement.
19 Contributions stop at age 65. At that point Medicare would become the
20 retiree's primary medical coverage.

21 Q. How were contributions, reimbursements and amounts to be capitalized
22 projected?

ACCOUNTING PANEL

1 A. The actual contributions, reimbursements and amounts capitalized were
2 projected using the same 17.2% factor that was applied to the health and life
3 insurance costs.

4 Q. Will it be possible for you to update your projection of health and life
5 insurance costs during the course of this rate proceeding for actual premium
6 increases?

7 A. Yes, the actual 2009 premiums for the Company benefit plans will be finalized
8 by January 2009. We plan to review the actual increases and would propose to
9 update this exhibit for known changes during the "update" phase of this
10 proceeding, if they differ substantially from the current projections.

11 Q. Please explain the next program change, the 1% adjustment for productivity?

12 A. As indicated earlier in our testimony, consistent with the adjustment reflected
13 in O&R's current electric rate plan (Case 07-E-0949), this adjustment reflects
14 a one percent reduction of forecast employee benefit insurance, pensions, and
15 OPEB costs. Salary and wages and the payroll tax elements reflect the
16 productivity adjustment within those items.

17 Q. Please describe the other components shown on Exhibit G-5, Schedule 4, page
18 2.

19 A. The next line includes various employee benefit costs such as employee
20 training, safety shoes and personnel administration. The Rate Year level was
21 based on the Historical Test Year and general escalation. The item labeled
22 restricted stock represents costs incurred as part of the Company's executive
23 compensation plan. This item was normalized out so that it would not to be

ACCOUNTING PANEL

1 funded by customers. Property insurance expense represents O&R's share of
2 policies that are administered by Con Edison. A normalizing adjustment was
3 made to annualize premiums paid during the Historical Test Year. General
4 Liability Insurance includes the cost of self-insured claims up to \$500,000 per
5 instance, excess liability premiums (for claims over \$500,000), Directors and
6 Officers ("D&O") insurance and a few small miscellaneous policies.

7 Q. How was the Rate Year level of expense calculated for General Liability
8 Insurance?

9 A. We calculated the Rate Year level of expense for General Liability Insurance
10 utilizing a three-year average of self-insured claim payments. This resulted in
11 a normalizing adjustment of \$(41,000) to the Historical Test Year level of
12 expense to bring it in line with the three-year average. The Historical Test
13 Year level of expense was then escalated by the general inflation rate in order
14 to calculate the Rate Year level of expense.

15 Q. How does the Company calculate the level of expense to be reserved in order
16 to provide for outstanding claims?

17 A. The Company's Risk Management and Law Departments review all
18 outstanding claims and develop an estimate annually, of the cost to satisfy
19 known claims. A reserve would then be provided for each claim up to the
20 Company's self-insurance cap of \$500,000. Amounts to be paid over this
21 amount are covered by an excess general liability insurance policy.

22 Q. Was it necessary to normalize the Historical Test Year level of workers'
23 compensation costs?

ACCOUNTING PANEL

1 A. Yes, we calculated the Rate Year level of expense for workers' compensation
2 insurance utilizing a three-year average of self-insured claim payments. This
3 resulted in a normalizing adjustment of \$(0.5 million) to the Historical Test
4 Year level of expense to bring it in line with the three-year average. The
5 capitalized offset is \$147,000. This adjustment also included an adjustment to
6 eliminate all asbestos related claim costs applicable to electric operations for
7 the divested plants. The Historical Test Year level of expense was escalated
8 by the general inflation rate in order to calculate the Rate Year level of
9 expense.

10 Q. Does the Company use a third-party administrator to handle its workers'
11 compensation claims?

12 A. Yes, Orange and Rockland uses Sedgwick to administer all claims.

13 Q. How does the Company calculate the workers' compensation reserve it
14 maintains on its books to settle outstanding claims?

15 A. The Company consults with Sedgwick to evaluate outstanding workers'
16 compensation claims. Sedgwick generates reports for the Company that show
17 the estimated reserves required to satisfy each identified claim less any third-
18 party reimbursements. This estimated cost is recapped and the reserve is
19 established for each claim up to the Company's self-insurance cap of
20 \$350,000. Amounts to be paid over this amount are covered by an excess
21 workers' compensation insurance policy.

22 **Regulatory Costs and Amortizations**

23 Q. What costs are included in Exhibit G-5, Schedule 5, Page 2?

ACCOUNTING PANEL

1 A. The Regulatory Costs and Amortizations schedule includes the allowance for
2 Research and Development (“R&D”), amortizations, Outreach and Education,
3 and expenses related to the low-income program.

4 Q. Please address the R&D component.

5 A. In accordance with previous NYPSC decisions and its 1978 Technical Release,
6 the Company reconciles actual R&D recoveries and expenditures. Gas R&D
7 costs reflect primarily the Company’s share of R&D costs included in the
8 NYPSC annual assessment, O&R’s participation in the New York Gas Group,
9 and the gas portion of the R&D costs charged to Orange and Rockland as a
10 shared service. Orange and Rockland projects that the current level of expense
11 plus general escalation will be an adequate level of revenue in the Rate Year.

12 Q. Please address the amortizations.

13 A. The amortization of the prior conservation fund expires at the end of the
14 current rate plan. Company witness Hutcheson increased the amortization of
15 gas mains by \$150,000 in the rate year. This is addressed in the testimony of
16 Company witness Hutcheson and shown on Exhibit __ (G-12), Schedule 4.

17 Q. Please address the low-income component.

18 A. The low-income component reflects the amortization of deferred credits set up
19 to fund the Company’s low-income program. In addition to passing back the
20 deferred credits to customers, the Company also has incurred \$475,000 in the
21 historic period in low-income program costs. Company witness Quin
22 discusses the rate year projection of \$500,000.

23 **Pension and OPEB Costs**

ACCOUNTING PANEL

1 Q. Please describe the accounting procedures followed by the Company to record
2 pension costs.

3 A. The Company's pension expense has been calculated in accordance with the
4 provisions of Statement of Financial Accounting Standards No. 87 ("SFAS No.
5 87") and the Commission's Statement of Policy and Order Concerning the
6 Accounting and Ratemaking Treatment for Pensions and Post-retirement
7 Benefits Other Than Pensions (Case 91-M-0890), issued and effective
8 September 7, 1993, ("Pension and OPEB Order"). In accordance with the
9 Commission's Accounting Order dated September 22, 1987 and the
10 Commission's decisions in Cases 29046/47, 88-G-011, 89-E-175, 91-G-0128,
11 92-G-0050, 99-G-1695, 02-G-1553, and 05-G-1494, the Company defers any
12 difference, including the income tax effect, between the allowance provided in
13 current rates for pension costs and the corresponding book expense recorded
14 under the provisions of SFAS No. 87. Assumptions used to calculate the
15 Company's SFAS No. 87 expenses are listed and described in the workpapers
16 that were filed in support of this Exhibit. Using these assumptions, it was
17 projected that at the beginning of the Rate Year, the deferred balance would be
18 approximately \$3.7 million, representing an under-recovery of the Company's
19 SFAS No. 87 Pension Expense. It is proposed that this deferred balance be
20 amortized over a 36-month period. Supporting workpapers submitted with this
21 Rate Filing show the components of the average monthly balance of deferred
22 pension costs for the Rate Year.

ACCOUNTING PANEL

1 Q. How is the Company accounting for the difference between the rate base
2 deductions included in rates and the actual current balance?

3 A. In conformity with the Commission's Pension and OPEB Order (pp. 19-20)
4 and the Company's Rate Order in Case 05-G-1494, the Company has accrued
5 carrying charges on the pension recoveries not deposited into an external fund,
6 in excess of the Company's imputed rate base deduction. The Company will
7 accrue approximately \$450,000 through the end of the linking period (*i.e.*,
8 October 31, 2009). We would note that we have eliminated the rate base
9 deduction for pensions going forward due to the impact that current market
10 conditions have had on our pension fund assets. We are requesting
11 authorization to accrue interest at a pre-tax rate of return if the cumulative
12 pension funding exceeds the amounts recovered in rates.

13 Q. How does the Company propose to account for the excess of cost recoveries to
14 amounts funded going forward?

15 A. The Company proposes to continue its current procedures. The Company will
16 continue to fund its pension obligation to the extent it can in a tax effective
17 manner and continue to compensate customers for the use of funds held by the
18 Company.

19 Q. Will the Company incur additional supplemental pension costs going forward
20 and if so are you requesting rate treatment for these costs?

21 A. The Company will continue to record an annual accrual for the expense of
22 approximately \$0.7 million per year and should be allowed to recover this
23 expense.

ACCOUNTING PANEL

1 Q. Are there other costs included in Pension Expense?

2 A. Yes, the Company has a partial 401(K) Matching Plan, whereby the Company
3 matches half of employee contributions into their 401(K) Plans up to a
4 maximum of 6% (equivalent to 3% of employee contributions). The cost for
5 the 401(K) Plan was calculated by taking the actual expense incurred during
6 the Historical Test Year and escalating the cost by the GDP Price Deflator.

7 Q. Please describe the Accounting Procedures followed by the Company to record
8 OPEB costs?

9 A. Since the adoption of Statement of Financial Accounting Standards No. 106
10 ("SFAS No. 106") on January 1, 1992, the Company has calculated its OPEB
11 obligation in accordance with the provisions of this Statement and in
12 conformity with the Commission's Pension and OPEB Order. Prior to that
13 time the Company used the "Pay-As-You-Go" method for both financial and
14 ratemaking purposes. The Commission's decisions in Cases 93-M-0849, 93-
15 G-0779, and 95-E-0491 allowed the Company to start recovering current and
16 previously deferred OPEB costs beginning on May 1, 1996. The Company's
17 current rate allowance of \$7.625 million was established in Case 05-G-1494.
18 The current rate allowance has been in effect since November 2008.
19 Assumptions used to calculate the Company's SFAS No. 106 expense are
20 listed and described in workpapers that were filed in support of this Exhibit.
21 Using these assumptions, at the beginning of the Rate Year, the projected
22 deferred balance will be approximately \$1.3 million. We are proposing to
23 amortize this balance over 36 months. The unamortized transitional obligation

ACCOUNTING PANEL

1 at the beginning of the Rate Year will be approximately \$1.7 million, we will
2 continue to amortize this balance through December 31, 2012. As we have
3 indicated earlier we will seek to calculate interest not only calculated when
4 OPEB recoveries exceed funding, but also if the Company is legally required
5 to fund more than its current rate recoveries by the Pension Benefit Guarantee
6 Corporation. Since the Company has been able to fully utilize rate recoveries
7 in a tax effective manner to fund its OPEB obligation, no interest has been
8 accrued.

9 Q. Please describe the Medicare Part D Deferral.

10 A. Medicare legislation was enacted in 2004 that will grant Medicare recipients a
11 partial reimbursement of prescription drug costs starting in 2006. The
12 projected reimbursement applicable to Company employees and retirees was
13 factored into the estimated OPEB costs calculated by the Company's actuaries.
14 One additional benefit not reflected in their calculations relates to the point
15 that the Medicare reimbursements will not be subject to federal or state income
16 taxes. As a result the Company has estimated and deferred this tax benefit for
17 customers and would propose to pass it back over 36 months. The ongoing
18 benefit has been reflected as an adjustment to the Company's ongoing state
19 and federal income taxes on Exhibits G-4, Schedules 5 and 6.

20 Q. What steps has the Company taken to control OPEB Costs?

21 A. Since the adoption of SFAS No. 106 in January 1992, the Company has
22 reduced its net periodic costs by (i) the use of "Caps" or limits on the level of
23 benefits to be paid, (ii) the requirement of contributions from retirees to offset

ACCOUNTING PANEL

1 a portion of the costs, (iii) the use of mail order drug plans, and (iv) the move
2 to premium based insured plans and HMOs.

3 Q. Will it be possible for you to update your projection of Pension and OPEB
4 costs during the course of this rate proceeding for actuarial updates that factor
5 in the Company's actual 2008 experience?

6 A. Yes, it is anticipated that the Company's actuaries will update their
7 calculations of the Company's Pension and OPEB cost during the second
8 quarter of 2009, to reflect the Company's actual 2008 experience and updates
9 to the assumptions. We would propose to update these exhibits to reflect this
10 information during the "update" phase of this proceeding, if it differs
11 substantially from the current projections.

12 **Uncollectible Accounts**

13 Q. Please address Exhibit G-5, Schedule 7.

14 A. Exhibit G-5, Schedule 7, presents the projected uncollectible accounts
15 expense. The projections are based on the ratio of bad debt customer account
16 write-offs, net of collections, to sales to customers for the three-year period
17 ended June 30, 2008. For each one hundred dollars of revenue billed to
18 customers, \$0.47 was written off as uncollectible. This ratio was then applied
19 to projected revenues from sales to customers for the Rate Year. The
20 adjustment to the Historical Test Year level of uncollectible accounts expense
21 is required to adjust the book expense amount, which is determined using the
22 reserve method of accounting, to the average level of customer account write-
23 offs incurred during the last three-year period.

ACCOUNTING PANEL

1 Q. Are you proposing any changes with regards to the recovery of this expense
2 going forward?

3 A. No, in Case 05-G-1494 the Company was allowed to recover uncollectible
4 costs in two components: an allowance applicable to base rates and an
5 allowance applicable to the unbundled components of customers' bills (*e.g.*,
6 Gas Supply Charge). The actual factors used in the riders should be updated at
7 the end of this case to reflect the approved uncollectible rate on a revenue
8 neutral basis.

9 **Environmental Costs**

10 Q. Please describe Orange and Rockland's former MGP sites.

11 A. Orange and Rockland and its predecessor companies manufactured coal gas
12 and water gas for local use prior to the introduction of natural gas in the
13 1940's. The Company has identified seven sites ("MGP Sites") at which it or
14 its predecessors operated MGP facilities. Pursuant to two Consent Orders that
15 O&R entered into with the New York State Department of Conservation
16 ("NYSDEC"), O&R has been actively investigating these MGP sites. In
17 addition, since the execution of these Consent Orders, O&R has identified and
18 investigated another site, McVeigh Road, which will require remediation. To
19 date, O&R has completed remediation at one of its MGP sites in Haverstraw
20 and has also completed remediation of the land portion (Operable Unit 1) at
21 the Nyack MGP site.

22 Q. Please describe the current status of each of these sites.

23 A. A brief description and status summary for each of the sites follows:

ACCOUNTING PANEL

Nyack Gas Plant

1 This site is presently a privately-owned vacant property located along Gedney
2 Street and the Hudson River in Nyack. Significant subsurface contamination
3 of soils, groundwater and bedrock were found on the site. In addition, MGP
4 impacts were identified in the Hudson River sediments. NYSDEC issued a
5 Record of Decision (“ROD”) for the land portion, Operable Unit 1 (“OU-1”)
6 of the site in March 2004 requiring remediation of impacted media.
7 Remediation activities for OU-1 were completed in November 2007 and
8 included a combination of excavation and in situ treatment technologies
9 including chemical oxidation and solidification. Investigation of the river
10 sediments was completed in October 2008 and a Feasibility Study (“FS”) will
11 be developed in early 2009.

Suffern Gas Plant

14 This site is comprised of properties owned by both O&R and third-party
15 owners. The private properties are operated commercially, and O&R has gas
16 operations on several portions of the site. O&R is currently in the process of
17 purchasing the former MGP site property that had been operated by Econo
18 Truck/US Bus since the 1950s. This purchase will enable O&R to implement
19 the necessary remediation to address the MGP impacts in subsurface
20 structures, soils and groundwater at and around the site. Sentinel wells,
21 installed between the site and the Village of Suffern well field are monitored
22 on a quarterly basis to ensure that the Village water supply wells are not being

ACCOUNTING PANEL

1 impacted by site contaminants. Additional supplemental investigation
2 activities are planned for late 2008/early 2009.

3 Haverstraw Gas Plant (93 B Maple Avenue)

4 This site is privately owned and located in a residential area, with several
5 residences immediately adjacent to the site. Remediation of the site and off
6 site properties was completed in 2004. NYSDEC issued two RODs (i.e., in
7 2005 and 2006) for the various remediation phases. No further action is
8 required at the site except for development of a Site Management Plan that
9 maintains the existing building in place on the 93B Maple Ave. site as an
10 engineering control.

11 Haverstraw Gas Plant (Clove & Maple)

12 This site is owned by O&R and operated as a gas regulator station. A
13 comprehensive RI and numerous supplemental investigations have been
14 completed on the site and on several adjacent properties. MGP residuals and
15 contamination have been found in subsurface soils and groundwater both on
16 and off site including an apartment complex and several residential properties.
17 MGP impacts that are associated with this site also have been detected in
18 Hudson River sediments. A FS to evaluate remedial alternatives will be
19 completed in 2009.

20 Fulton Street - Middletown

21 This site is a privately owned commercial property. A comprehensive RI and
22 numerous supplemental investigations have been conducted on the site and on
23 several adjacent properties including property operated by the U.S. Postal

ACCOUNTING PANEL

1 Service. These investigations have determined that significant MGP impacts
2 are present in subsurface structures, soils and groundwater on site; on some of
3 the off site properties; and beneath the road between them. A FS to evaluate
4 remedial options will be completed in 2009.

5 Genung Street - Middletown

6 This property is owned by O&R and is comprised of four individual parcels.
7 Three of the parcels are vacant, and one is operated by O&R as a gas regulator
8 station. O&R has completed a comprehensive RI and FS on the site.
9 Significant contamination in subsurface soils and groundwater is present on
10 one of the parcels. Minor impacts have been noted in the other three parcels.
11 A ROD was issued by NYSDEC in March 2005. The ROD stipulates that
12 impacted soils will be excavated from the site; soil or pavement cover will be
13 provided in areas exceeding certain regulatory guidance values and
14 institutional controls will be imposed to control the future use and
15 development of the site. Given the greater priority for the remediation of the
16 Company's other MGP sites, O&R and NYSDEC have agreed that the actual
17 remedial work at this site likely will not occur until close to end of the
18 Company's remediation program.

19 Port Jervis Gas Plant

20 This site is owned by O&R and functions as a satellite operating center for
21 field crews. A comprehensive RI and numerous supplemental investigations
22 have been completed at the site, on several adjacent properties and in and
23 along the Delaware River. Significant MGP impacts and contamination have

ACCOUNTING PANEL

1 been identified in subsurface structures, soils and groundwater both on and off-
2 site. No significant impacts to the Delaware River have been identified. The
3 FS was completed in 2006 and NYSDEC issued a ROD in December 2007.
4 The ROD requires installation of a sub-slab depressurization system and a
5 floor in the basement of the restaurant adjacent to the site to address potential
6 soil vapor intrusion issues. In addition, the ROD calls for installation of
7 numerous groundwater treatment wells on an off site property. O&R will
8 likely have to purchase this property to implement the remedy.

9 McVeigh Road

10 This site was identified in 2001 during the construction activities for the
11 installation of a fire hydrant for O&R's new Middletown Electric Substation.
12 The source of the contamination is unknown, but has been confirmed to be
13 MGP related. The impacts are limited to sediments located within a small
14 section of Monhagen Brook. Remediation of the site will require excavation of
15 impacted sediments and will be conducted as a spill cleanup under NYSDEC
16 direction. This remediation is planned for early 2009.

17 Q. What is the net deferred balance for MGP costs at June 30, 2008?

18 A. The balance on the books at June 30, 2008 for the O&R gas portion of MGP
19 costs is \$2.8 million.

20 Q. What costs relating to MGP Sites does Orange and Rockland project that it
21 will incur?

22 A. The Company estimates that it will incur approximately \$15.2 million through
23 October 31, 2010 on remediation efforts. The Gas Department's share of these

ACCOUNTING PANEL

1 costs would be approximately \$4.4 million. The Company will also be
2 amortizing \$2.1 million from July 1, 2008 through the end of the current rate
3 plan.

4 Q. How do you propose to recover MGP costs?

5 A. Deferral accounting of these costs should continue. We would propose to
6 recover the current deferral and projected spending over 36 months. As noted
7 above, Orange and Rockland's gas operations currently have a net deferred
8 spending balance as of June 30, 2008 of approximately \$2.8 million. When
9 this balance is combined with the projected spending of \$4.4 million and the
10 amortization of \$2.1 million, it results in a projected balance of \$5.1 million at
11 October 31, 2010. Based on a three-year amortization, the annual allowance
12 would be \$1.7 million. This rate treatment will avoid the accumulation of a
13 large deferral.

14 Q. Has Orange and Rockland sought recovery for any of the investigation costs
15 from any liability insurance policies that extended coverage to the MGP Sites?

16 A. Yes. Orange and Rockland resolved its MGP claims in September 2002 with
17 an insurance company that sold O&R excess liability insurance policies during
18 the periods 1978 – 1983, and 1986 – 2001. The terms of the settlement
19 agreement between O&R and the insurance company are confidential.

20 Another insurance company, Travelers Insurance, Orange and Rockland's
21 liability insurer until 1978, sued Orange and Rockland in New York Supreme
22 Court in 2002 for a declaratory judgment that it has no duty to indemnify
23 Orange and Rockland for costs incurred for remediation at seven former MGPs

ACCOUNTING PANEL

1 that Orange and Rockland's predecessors owned or operated in New York
2 State beginning in the mid-1800s. Currently, the litigation is in the summary
3 judgment phase. The parties have chosen a trial site (the MGP formerly
4 located in Nyack, NY) and are anticipating a trial date in the spring of 2009.
5 The major issues in the case will involve whether Orange and Rockland
6 provided timely notice to Travelers of the property damage at the sites and
7 whether the policies at issue cover the type of damage that occurred at the
8 sites. There are also issues involving missing insurance policies that neither
9 Orange and Rockland nor Travelers have been able to locate. We expect the
10 trial on the Nyack site to last approximately one month. O&R is incurring
11 substantial legal costs in its litigation with Traveler's.

12 **Regulatory Commission Expenses**

13 Q. Please explain the regulatory commission expense cost element on Exhibit G-
14 5, Schedule 10.

15 A. This cost element includes the assessments of the NYPSC and the amortization
16 of rate case costs. In establishing the Rate Year projection for the NYPSC
17 assessment, we escalated the bill paid in September 2008 using the general
18 inflation factor.

19 Q. Is the Company concerned about any other regulatory commission costs that it
20 may incur during the rate plan approved by the Commission in this
21 proceeding?

22 A. Yes. Currently, the Commission is conducting a management audit of Con
23 Edison. While the Commission has not scheduled such an audit for O&R, in

ACCOUNTING PANEL

1 the event that the Commission does schedule such an audit during the rate
2 plan, the Company requests authorization to defer any regulatory costs relating
3 to such an audit (as well as any other new regulatory proceeding commenced
4 during the rate plan).

5 **Other O&M Expenses**

6 Q. Which costs were included in Other O&M Expenses?

7 A. Exhibit G-5, Schedule 11 includes the following cost elements, which the
8 Company proposes to escalate using the inflation factor addressed later in our
9 testimony:

- 10 • Advertising;
- 11 • Building Services;
- 12 • Information Technology Solutions;
- 13 • Legal & Other Professional Services;
- 14 • Rents;
- 15 • Telecommunications;
- 16 • Transportation;
- 17 • Materials and Supplies; and
- 18 • Corporate Fiscal Expenses.

19 These costs were first normalized and then escalated by the appropriate
20 inflation factor. Exhibit G-5, Summary, Page 3, explains the rationale
21 underlying each normalizing adjustment.

22

23 **Common Utility Plant**

ACCOUNTING PANEL

1 Q. Please describe Exhibit G-6, Schedules 1 - 4.

2 A. Exhibit G-6, Schedule 1, presents the Company's forecasted gas transmission
3 and distribution capital expenditures for the Rate Year, Rate Year 2 and Rate
4 Year 3. Exhibit G-6, Schedule 2, presents the forecasted gas transmission and
5 distribution plant additions for the same period. Exhibit G-6, Schedule 3 and
6 Schedule 4 present the Company's forecasted common capital expenditures
7 and plant additions for the Rate Year, Rate Year 2 and Rate Year 3. In his
8 testimony, Company witness Diloreto supports Schedules 1 and 2. We support
9 Schedules 3 and 4.

10 Q. Please describe the common general plant additions.

11 A. The forecasted cost of common general plant additions is included on Exhibit
12 G-6, Schedule 4, at 100%. The common general plant additions for the Rate
13 Year include blanket additions of \$8.255 million and other general project
14 additions of \$2.865 million. The major items included in the blanket additions
15 are as follows: the Company's vehicle purchase program of \$3.140 million;
16 communications costs, including microwave system and fiber optic upgrades
17 of \$913,000; and office computer equipment, including personal computer
18 purchases and LAN system upgrades of \$1.973 million. Other general project
19 additions, other than those included in the blanket additions, primarily include
20 the cost of various energy efficiency facility projects including the installation
21 of an automated remote control HVAC system and modular furniture
22 replacement that will improve the heating and ventilation in the building. In
23 Rate Year 3 the Company also plans to replace the generators at its West

ACCOUNTING PANEL

1 Nyack and Middletown locations. In addition, the common plant additions
2 include the Company's costs for various shared service projects that will result
3 in O&R and CECONY being on common platforms. These system
4 enhancements include the costs for a new budget development system and new
5 financial general ledger and supply chain system that is projected to go in-
6 service in 2012. Other general project costs also include the cost of various
7 capitalized building repairs and telecommunication improvements at Company
8 facilities.

9 Q. How will you derive the portion of these expenditures that will be allocated to
10 gas plant?

11 A. As discussed above, in its Order in Case 99-G-1695, the Commission approved
12 a four-part formula for allocating common general plant to electric and gas
13 utility operations. The Company used this Commission-approved
14 methodology to allocate common general plant to gas operations.
15

16 **GENERAL INFLATION FACTOR**

17 Q. Please address the general inflation factors used by Orange and Rockland as
18 shown on Exhibit G-10.

19 A. General inflation factors as forecast in the Blue Chip Economic Indicators
20 were utilized to escalate various elements of the cost of service as addressed
21 throughout our testimony and the testimony of other witnesses. Based on this
22 publication, dated October 10, 2008, the projected inflation rate for the twelve
23 months ended June 30, 2008 to the twelve months ending October 31, 2010, is

ACCOUNTING PANEL

1 1.053, or 5.3%. As with past practice in Orange and Rockland rate cases, we
2 recommend that the inflation factors be updated to reflect the latest available
3 inflation forecasts before a final decision in this proceeding.

4

5

THREE-YEAR RATE PLAN

6 Q. Have you developed a three-year rate plan proposal as an alternative to a one-
7 year case? If so, please explain how an agreement of this length would benefit
8 the Company's customers.

9 A. Yes. Multi-year rate plans provide the Company with the flexibility to
10 schedule and execute critical programs in the most cost effective manner.
11 They also place a greater responsibility on the Company to manage its
12 resources over several years when there may be large swings in economic
13 conditions. When the Company succeeds in managing its resources, customers
14 benefit during successive rate periods. A three-year rate plan balances the
15 impact of future uncertainties on customers and the Company. It permits the
16 Company and the Commission to review the results of the plan and reset rates,
17 if necessary, without allowing too much time to elapse should events cause the
18 economic conditions on which the rate plan is premised to be materially
19 different from the economic conditions affecting the Company, its customers
20 and its shareholders.

21 Q. Can you explain how your multi-year proposal would work?

22 A. The Company is essentially proposing that the rates set for RY1 become the
23 base from which projections would be developed for the second and third years

ACCOUNTING PANEL

1 of the rate plan. The Company is further proposing that the Commission adopt
2 a series of staged rate changes for RY2 and RY3. We would like to emphasize
3 that, by proposing a three-year plan in the alternative, the Company is not
4 waiving its rights to file for new rates to take effect on November 1, 2010, if
5 the Company views the rate change granted by the Commission for RY1 to be
6 inadequate, or the terms for RY2 and / or RY3 under a multi-year rate plan to
7 be unreasonable. The various three-year amortizations proposed throughout
8 our testimony are consistent with the three-year plan alternative, but are also
9 workable if rates are set only for the Rate Year in this proceeding. The multi-
10 year rate plan includes revenue requirements for the rate years ending October
11 31, 2011 and 2012, respectively. Exhibit G-7, Summary sets forth the revenue
12 requirements for each of the three rate years ending October 31, 2010, 2011
13 and 2012. The first line represents the revenue requirement increase of \$17.8
14 million for RY1. The next several lines include projected changes in firm and
15 non-firm sales revenues, increases in operating expenses due to inflationary
16 increases, projected pension cost decreases, depreciation and property tax
17 increases, rate base additions, and the related income tax impacts of the above
18 items. The Commission has previously recognized such multi-year rate
19 adjustments for Orange and Rockland, and such adjustments are necessary to
20 provide the Company an opportunity to maintain a reasonable rate of return
21 over a multi-year period. The projected revenue requirement increases are
22 \$6.9 million for RY2, and \$3.9 million for RY3.

23 Q. How were firm and non-firm revenues projected?

ACCOUNTING PANEL

1 A. The Forecasting Panel provided us with the forecast sales volumes and base
2 revenues. Purchase gas costs were provided to us by Company witness
3 Olmsted.

4 Q. Please address the projected inflation and property tax increases for RY2 and
5 RY3.

6 A. The inflation increases are derived by applying a 2.1% GDP inflation factor to
7 O&M expenses excluding labor, fixed amortizations and pension costs. Labor
8 was escalated at 5.92% in RY2 and 4.06% in RY3 less a 1% productivity
9 adjustment. Company witness Hutcheson provided estimated property tax
10 increases. As noted earlier, the property tax projections are subject to
11 reconciliation.

12 Q. Please address the projected rate base and depreciation expense for RY2 and
13 RY3.

14 A. The average gas rate base for the rate years ending October 31, 2011 and 2012
15 was increased to reflect the Company's construction budget net of accrued
16 depreciation, changes in working capital requirements and deferred taxes.
17 Increased depreciation expense associated with the projected plant additions
18 was also reflected.

19 Q. Did you calculate the annual revenue increases if the revenues were to be
20 authorized under a levelized approach?

21 A. Yes. In the past the Commission in approving multi-year deals has preferred to
22 levelize the revenue increases over the term of the agreement. As shown on
23 Exhibit G-7, the levelized annual revenue increases are \$11.9 million per year.

ACCOUNTING PANEL

1 Q. Are there risks associated with multi-year rate plans?

2 A. Yes. The operating needs of the Company and service expectations of
3 customers can change over time, and these changes can result in the need for
4 investments or expenses over and above those projected on a multi-year basis.
5 There is also the potential for rising inflation and interest rates.

6 Q. Are there specific examples of such risks?

7 A. Yes. Over the course of the current multi-year gas rate agreement, O&R
8 experienced a number of factors that have negatively impacted its gas
9 business. For example, due to lower average customer usage, O&R did not
10 achieve the level of firm sales assumed in the revenue requirements over two
11 years of the existing rate plan through October 31, 2008. Finally, due to
12 factors we previously identified, post-retirement benefit costs have increased
13 dramatically, and although these cost increases are deferred, they ultimately
14 need to be collected through rates. Achieving timely recovery of such costs is
15 more difficult when there is upward pressure on rates due to other costs
16 increases and the need to continue to invest in infrastructure at a rate that
17 exceeds sales growth. The multi-year rate plan needs to address these risks in
18 a reasonable fashion.

19 Q. Do you have any other comments regarding the projected revenue
20 requirements for RY2 and RY3?

21 A. Yes. The projected revenue requirements for RY2 and RY3 are based on
22 projections of inflation, property taxes, and construction expenditures
23 developed using the best information available to the Company at the time of

ACCOUNTING PANEL

1 this filing. As noted above, that information can change with the passage of
2 time. It is possible that inflation will begin to accelerate causing the
3 Company's operating expenses to increase at a rate greater than that assumed
4 in developing the projected revenue requirements. Also, operating
5 requirements can change causing the need for temporary or permanent changes
6 in resources, including the Company's construction budget. It is for these
7 reasons that the revenue requirements for RY2 and RY3 should be updated,
8 during this proceeding, based on the latest available information.

9 Q. Has this type of multi-year plan been applied to O&R in the past?

10 A. Yes. The NYPSC has approved multi-year rate agreements for O&R where
11 rates were established based on the rate year cost of service, and second and
12 third staged increases in rates were allowed for the recovery of increased costs
13 such as inflation, property taxes, and rate base growth. These cost increases
14 have been offset in part by projected sales growth. For O&R, it is essential
15 that a multi-year rate plan allow for the current recovery of these items.

16

17 **DISTRIBUTION INFRASTRUCTURE SURCHARGE**

18 Q. Does the Company have a proposal related to capital expenditures associated
19 with distribution infrastructure improvements?

20 A. Yes. The Company recognizes that it and its customers are being impacted by
21 the unprecedented economic conditions that currently exist. The Company is
22 mindful of the need to control and minimize costs.

ACCOUNTING PANEL

1 In addition, the Company has a public service obligation to provide safe and
2 reliable service. This requires the Company to make much needed investment
3 in its gas distribution system. As discussed in the testimony of Company
4 witness Perkins, the recovery of these expenditures on a current basis is crucial
5 to the maintenance of the Company's financial integrity in order to access the
6 financial markets for funding of these investments. These large capital
7 expenditures have historically been reviewed and included in rates through
8 base rate cases. A more timely review and recovery of these expenditures
9 would benefit customers phasing these costs in rates as they are incurred rather
10 than waiting for a rate case to be filed. In addition, a more current review and
11 recovery of these costs will support the Company's bond rating that will
12 permit the Company continued access to the financial markets. The
13 Company's proposal affords the Commission and interested parties, the review
14 and auditing procedures that are currently in place.

15 Q. Is the Company proposing an alternative that can be used to recognize the
16 projected capital investment costs proposed by Orange and Rockland for its
17 gas distribution system?

18 A. Yes, the Commission should consider a Distribution Infrastructure Surcharge
19 ("DIS"). The Company would be permitted to establish a surcharge applicable
20 to all delivery customers (except interruptible customers or customers with
21 contractually determined prices) that would recover the carrying costs (return,
22 depreciation and property taxes) on projected capital investments. The
23 Company would reconcile the carrying costs collected from customers to the

ACCOUNTING PANEL

1 actual carrying costs due the Company based on actual investment made. Any
2 over or under-collection would be included in the calculation of the following
3 year's DIS.

4 Q. What procedure does the Company propose for the DIS surcharge?

5 A. The Company would file an annual forecast of planned capital expenditures 60
6 days prior to the twelve month period for which the DIS surcharge is to be
7 effective. The Commission Staff would review the Company's filing and make
8 revisions as necessary. The revised investment amount would become the basis
9 for the establishment of the surcharge rate. Within 60 days following the end
10 of the relevant annual period, the Company would file a report with the
11 Commission detailing the investments made and a calculation of any under or
12 over-collection.

13 Q. What is the benefit of a DIS?

14 A. First, the DIS would provide a simultaneous review of the capital expenditures.
15 Customers only would pay carrying costs on investments actually made and
16 the surcharge would be fully reconciled. Second, the current recovery of these
17 costs, which is one of the main drivers for the needed rate relief, would
18 enhance the Company's access to the capital markets. Third, the procedure
19 would be administratively simpler than a full base rate case, thus requiring less
20 Commission and Company resources and expense.

21

22 **TRUE-UPS AND DEFERRED ACCOUNTING**

23 Q. Does the Company currently employ the use of deferred accounting as

ACCOUNTING PANEL

1 permitted under SFAS No. 71, Accounting for Regulated Businesses?

2 A. Yes, the Commission has authorized the Company to utilize deferred
3 accounting to match the recognition of expenditures with the recovery of
4 certain costs when they are either beyond our direct control or the timing of the
5 actual expenditure is not certain.

6 Q. Are you proposing to continue the use of deferral accounting for the costs that
7 the Commission has previously authorized?

8 A. Yes, we propose to continue the true-up mechanisms allowed in the current
9 rate plan, whether in a one-year rate determination or the proposed three-year
10 rate plan, except that the target levels should be reset to the Company's
11 projected levels of expense (*e.g.*, property taxes, pensions and OPEBs) that are
12 included in this filing.

13 Q. Do you propose any additional deferrals?

14 A. Yes, we propose three additional deferrals. In the event of a multi-year rate
15 plan, given the likelihood of continuing disruption in the financial markets, the
16 Commission would need to provide some way of tracking debt costs in order
17 to protect the interests of the Company and its customers.

18 Q. Please describe your second proposed deferral.

19 A. The second deferral is for general inflation, which would also only apply if the
20 Commission approved a multi-year deal.

21 Q. Does the Company currently have a deferral for general inflation?

22 A. Yes, the Commission approved a deferral for general inflation for the
23 Company's electric operation in Case 07-E0949.

ACCOUNTING PANEL

1 Q. Please describe your proposed mechanism for the general inflation deferral.

2 A. If general inflation rates exceed 4.0% ("Inflation Threshold") on average over
3 the course of the multi-year rate plan and the Company's average gas earnings
4 are less than the authorized return, the Company will be allowed to defer
5 inflationary increases above the Inflation Threshold applicable to the following
6 expenses ("Inflation Pool"):

7 Direct Labor
8 Shared Services
9 Employee and Other Insurance Costs
10 T&D O&M
11 Regulatory Commission Expenses
12 Advertising
13 Information Technology Solutions
14 Legal & Other Professional Services
15 Rents
16 Materials and Supplies
17 Corporate Fiscal
18 Other O&M

19

20 Although the above-threshold calculation will be performed at the end of each
21 rate year, deferral will be triggered on a cumulative basis over the multi-year
22 term of the rate plan. For, example, if the multi-year rate deal was to be for
23 three years, actual inflation must exceed 12% over the three-year.

24 The deferral would be based on the lower of the following:

25 (a) Inflationary increases above the Inflation Threshold, determined using
26 Price Index numbers for Gross Domestic Product ("GDP") published
27 by the U.S. Department of Commerce, Bureau of Economic Analysis
28 ("BEA"),
29 applicable to the Inflation Pool; or

ACCOUNTING PANEL

1 (b) Actual costs incurred by the Company for the expenses, contained in
2 the Inflation Pool, above the Inflation Threshold.

3 For example, if during RY1, the inflation rate according to the Blue Chip
4 Economic Indicators is 6%, as compared to the actual 5% increase in the
5 expenses contained in the Inflation Pool, the deferral would be equal to 1%
6 (*i.e.*, 5% less the 4% threshold) of the Inflation Pool, provided that the
7 Company did not exceed its allowed earned common equity.

8 Q. Please describe your third proposed deferral.

9 A. On October 31, 2008, the Company filed a petition with the Commission
10 seeking authorization to defer incremental costs related to extraordinary
11 interest cost increases and for costs related to the refunding and refinancing of
12 two issues of tax exempt debt. These two issues, (*i.e.*, Series 1994A, \$55
13 million variable rate debt, and Series 1995A, \$44 million variable rate debt)
14 ("Pollution Control Debt") were used to finance pollution control equipment
15 located at the Lovett Generating Station ("Lovett"). In addition, in 1992 the
16 Company entered into an interest rate swap agreement to convert the floating
17 interest rate of the Series 1994A to a fixed interest rate. For various reasons, as
18 discussed in testimony of Mr. Perkins, it may be necessary for the Company to
19 refund this debt prior to the end of the rate year, October 31, 2009. The
20 Company's petition outlined the basis for deferral accounting. Under its
21 current electric rate plan, the Commission has authorized the Company to defer
22 incremental debt service costs (*i.e.*, interest and fees) associated with this debt,
23 applicable to electric operations. The Commission should offer similar relief

ACCOUNTING PANEL

1 with respect to the Company's gas operations. In the event the Pollution
2 Control Debt is refunded prior to October 31, 2009 or the end of the gas rate
3 plan approved by the Commission in this case, the Company would defer the
4 incremental costs associated with the retirement and refinancing of the
5 Pollution Control Debt for future recovery. The settlement of swaps will be
6 trued-up and amortized through the normal maturity date of the applicable
7 bonds (*i.e.*, 2014). In addition, the Company will reconcile its actual interest
8 and swap costs related to the Pollution Control Debt (including the use of a
9 bank credit facility) to the levels reflected in rates

10 Q. Does this conclude your direct testimony?

11 A. Yes, it does

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ACCOUNTING PANEL

Attachment A
Employee Positions Approved in O&R Electric
Base Rate Case No. 07-E-0949

Date of Hire

**Positions Approved In O&R
Electric Case 07-E-0949**

Weekly Employees:

1 Service Layout Estimator July 2009

Monthly Employees:

1 Community Relations Manager Jan. 2009
1 System Specialist-Call Center Oct. 2008
1 Environmental Remediation
Project Manager Sept. 2008
1 Customer Programs Analyst July 2008
1 Labor Relations Administrator April 2009
1 Training Specialist-Health and
Safety July 2010
1 Supervisor-LTS Dec. 2008

Total = 8 Employees

1

ACCOUNTING PANEL

Attachment B Requested New Employee Positions O&R Gas Base Rate Case

		<u>Date of Hire</u>
	<u>New Positions-This Case</u>	
	<u>Weekly Employees:</u>	
	1 Gas Dispatcher (Service Operator 1 st Class)	Jan. 2010
	4 Gas Fitter 1 st Class	Jan. 2010
	4 Gas Fitter 1 st Class	Jan. 2011
	1 Tool Room Mechanic	Jan. 2010
	1 Highway Repairer	Jan. 2010
	1 Locating Control Center Clerk	Jan. 2010
	1 Locator 1 st Class	Jan. 2010
	1 Locator 1 st Class	Jan. 2011
	2 Gas Troubleshooters	Jan. 2010
	(1) Senior Operations Coordinator (Attrition Savings)	Jan. 2012
	<u>Monthly Employees:</u>	
	1 Gas Distribution Supervisor	Jan. 2010
	1 Supervisor (Gas Const.)	Jan. 2010
	1 Supervisor (Gas Const.)	Jan. 2011
	2 Supervisor (General Gas Supv.)	Jan. 2010
	1 Planner (CAG)	Nov. 2009
	1 Admin. Support Analyst (CAG)	Nov. 2009
	1 Gas Engineer	Jan. 2010
	1 Engineering Coordinator	Jan. 2011
	1 Standards Engineer	Jan. 2012
	1 Gas Service Supervisor	Jan. 2010
	1 Gas Marketing Specialist	Nov. 2009
	1 Gas Safety Specialist	Jan. 2010
	Total = 28 Employees	
	Added During Rate Year	21
	Added During Rate Year 2	7
	Added During Rate Year 3	<u>0</u>
		28

ATTACHMENT C

Justification For Position Of
GAS SAFETY SPECIALIST

PURPOSE:

To coordinate all gas safety issues and regulations particularly related to the inspection of both contractor and Company field operations work sites so as to comply with OSHA regulations and Company procedures, and to evaluate weather existing safety policies and procedures are adequate.

Responsibilities:

1. Development, administration and coordination of Utility Public Safety and education programs. The goal is to expand our outreach programs for educating the public about the hazards associated with our gas distribution and transmission systems. This education will be presented to:
 - a. Fire Departments
 - b. Police Departments
 - c. Primary and Secondary Schools
 - d. Business Associations
 - e. Contractor Safety Associations
 - f. General Public (Safety Fairs)
2. Administer and coordinate the Gas Contractor Drug and Alcohol Compliance Program. Responsibilities include:
 - a. Review and acceptance of Contractor Drug and Alcohol Programs
 - b. Maintenance of the approved contractor "employee lists" used by CAG so that all contractor employees have been pre-employment screened and is currently in a random testing pool.
 - c. Coordinate contractor status with CAG, Gas Operations, Gas Technical Services and Gas Engineering.
3. Conduct Gas Contractor field safety audits so that field operation are compliant with existing procedures and to evaluate whether amendments for existing policies or new policies are needed.
4. Conduct Gas Operations field compliance inspections to evaluate their compliance with OSHA safety regulations and Operator Qualification requirements.
5. Administer and coordinate the expanding DriveCam Program (driver safety training device). The goal is to expand our DriveCam pilot project and add

ACCOUNTING PANEL

- 1 cameras to our Gas Department. This training tool has proven extremely
- 2 effective in O&R CMO where it has substantially reduced vehicle accidents
- 3 and unsafe actions.
- 4
- 5 6. Update of existing and development of new Safety Guidelines related to
- 6 Gas Operations. Safety Guidelines to be updated or developed:
- 7 a. Excavation & Trenching Safety
- 8 b. Atmospheric Monitoring
- 9 c. Permit Required Confined Space Entry
- 10 d. Gas Enclosed Spaces
- 11 e. Welding, Cutting and Hot Work
- 12 f. Exposure Assessments
- 13
- 14
- 15 7. Attend Gas Operations communications meetings so that they understand
- 16 the existing and newly developed Safety Guidelines. Expand our
- 17 involvement with Gas Utility Associations in order to learn what safety
- 18 strategies are being developed and utilized by other gas utilities.
- 19

**ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO**

1 **Q. Please state your name and business address.**

2 A. My name is Richard S. Di Loreto 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 “O&R”, or the “Company”) as Director, Gas Technical Services. In this position
7 I am responsible for gas engineering, contract administration, and gas control
8 center activities.

9 **Q. Please provide your educational background and professional experience.**

10 A. In 1989, I graduated from Pace University with a Bachelor of Business
11 Administration Degree in Management. In 1993, I graduated from Pace
12 University with an MBA Degree in Finance. I joined Consolidated Edison
13 Company of New York, Inc. (“Con Edison”) in February 1972, as an apprentice
14 in the Gas Operations Department in the Bronx. In 1982, I was promoted to 1st
15 line supervisor in gas construction in Bronx Gas Operations. I held a series of
16 positions of increasing responsibility there until 1989, when I was promoted to
17 Manager of Gas Quality Assurance. In 1991, I became a Manager in Central Gas
18 Engineering. In 1992, I became the Section Manager of the Corrosion Control
19 Department in Central Gas Operations. In 1994, I became the Section Manager of
20 the Liquefied Natural Gas (“LNG”) Plant. In 1996, I became the Section
21 Manager of the Gas Meter Shop. In 1997, I became the Section Manager of Gas
22 Distribution Services in Westchester Gas Operations. In 1999, I became the

**ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO**

1 Section Manager of Gas Distribution Services in Manhattan Gas Operations. In
2 2001, I was promoted to Department Manager of the Gas Emergency Response
3 Center for Gas Operations. In 2008, I assumed my present position of Director,
4 Gas Technical Services for Orange and Rockland.

5 **Q. Have you ever previously sponsored testimony before the New York State**
6 **Public Service Commission (“NYPSC”)?**

7 A. No.

8 **Q. What is the purpose of your testimony?**

9 A. I will provide an overview of Orange and Rockland’s gas business, describe the
10 Company’s planned plant additions and construction plans, discuss the
11 improvements the Company is implementing in its gas operations, describe
12 Orange and Rockland’s proposed performance mechanisms, address the
13 Company’s proposed compressed natural gas (“CNG”) pilot program, and discuss
14 the Company’s plans for closing its Service Classification No. 8, Interruptible
15 Transportation and Supplemental Sales (“SC 8”) to additional applicants.

16 **Background**

17 **Q. Please provide a brief overview of Orange and Rockland’s gas business.**

18 A. Orange and Rockland serves approximately 130,000 customers in a gas service
19 area comprising 615 square miles and encompassing 49 communities located in
20 Orange and Rockland Counties. O&R manages its operations from three crew
21 reporting locations, one in each of its Eastern, Central, and Western Divisions,
22 respectively. The system contains a total of 1,856 miles of gas main ranging in

**ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO**

1 size from 1-1/4" to 16" and accommodates an annual throughput of 22 billion
2 cubic feet ("BCF") of gas.

3 The piping system consists of four miles of transmission main, 1,812 miles of
4 high-pressure distribution main, and 40 miles of low-pressure distribution main.

5 The transmission system is comprised totally of cathodically protected wrapped
6 steel. The high-pressure distribution main is comprised of bare and/or
7 ineffectively coated steel, plastic and cathodically protected wrapped steel. The
8 low-pressure distribution main is comprised primarily of cast iron, and bare and
9 ineffectively coated steel. Cast iron and bare and/or ineffectively coated steel are
10 the oldest pipes in the system and continue to require high maintenance. These
11 piping systems are replaced when warranted by load growth in the areas they
12 serve, and by the Company's current gas main replacement program.

13 Customers are fed from over 115,000 services ranging in sizes from 1/2 inch to 8
14 inch. While many of the services are plastic, there is also a considerable number
15 of cathodically protected and unprotected steel services. The unprotected steel
16 pipe requires more maintenance as it ages. The cathodically protected steel pipe
17 performs well as long as proper protection is maintained. Plastic pipe installed
18 since the late 1970's continues to be problem free; however, earlier vintage Aldyl
19 plastic installations are beginning to show the impact of aging.

20 **Q. Please describe the transmission companies that serve the Company.**

21 A. Two transmission companies, Columbia Transmission Company ("Columbia")
22 and Millennium Pipeline Company, LP ("Millennium") serve O&R's Western

**ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO**

1 and Central Divisions located in Orange County. O&R's Eastern Division, which
2 is located in Rockland County, can accept deliveries from four different
3 transmission companies, Algonquin Gas Transmission Company ("Algonquin"),
4 Tennessee Gas Pipeline Company ("Tennessee"), Transcontinental Gas Pipe Line
5 Corporation ("Transco"), and Millennium.

6 **Q. Please describe the operational functionality of the O&R gas system.**

7 A. The O&R gas system in Rockland County is mature and well integrated, with four
8 transmission input alternatives. The distribution system has evolved and has been
9 constructed to provide substantial system support for loss of a transmission
10 supply. However, some local improvements are needed to improve the reliability
11 and system integrity in the event of distribution contingencies. As new loads are
12 added to the system, gas distribution is usually readily available. In contrast, the
13 gas system in Orange County is dependent upon only two transmission pipelines
14 (*i.e.*, Columbia and Millennium). In addition, the distribution systems fed from
15 gate stations tapped from Millennium are extended routinely to serve new loads,
16 as natural gas is the heating fuel of choice. These extensions have added to the
17 radial nature of the gas distribution system in Orange County and do not provide
18 sufficient linkage to the other gate station radials to provide optimal network
19 system support and reliability.

20 **Q. Does O&R have any propane facilities?**

21 A. Yes. Although O&R retired its Suffern and Orangeburg propane-air peak shaving
22 plants in 2002, its Middletown propane-air peak shaving plant in Orange County

**ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO**

1 currently remains operational. The Middletown plant will be decommissioned
2 and retired upon the completion of the new Millennium gas transmission pipeline,
3 when the availability of out of system storage can replace the functionality of the
4 plant, which is scheduled in 2009. Upon retirement of the Middletown plant,
5 Maintenance and Inspection requirements specific to the plant will be reduced.
6 The Company will redirect any freed-up resources to inspection and maintenance
7 requirements on the additional equipment installed at gate and regulator stations.

8 **Plant Additions and Capital Plans**

9 **Q. Are you familiar with O&R's planned plant additions and construction**
10 **plans?**

11 A. Yes.

12 **Q. Was Exhibit __ (G-6) prepared by you or under your direction?**

13 A. Yes. Exhibit ____ (G-6) lists the Major Plant Additions that O&R proposes in this
14 proceeding, along with their in-service dates. Orange and Rockland is initiating a
15 number of major projects in order to improve the reliability and security of its gas
16 system.

17 **Q. Please describe the major projects to be completed or initiated during the**
18 **Company's proposed three-year rate plan (i.e., November 1, 2009 through**
19 **October 31, 2012).**

20 A. A description of these projects follows:

**ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO**

Gas Mains

Washingtonville to Chester Tie

In 2009, O&R will have completed the 2nd phase of a 3-phase system reinforcement project in the Washingtonville/Chester area. In 2010, O&R will complete the final phase of the project with the installation of approximately 12,000 feet of 12" plastic, 80 psig design distribution main from Craigville Road along Rte. 94 to Chester to enhance system reliability of supply to an area which serves more than 9,000 customers. This area is projected to have continued load growth over the next ten years. The total cost of phase 3 of this project will be approximately \$2.275 million.

Middletown/Wallkill Main Reinforcement

The Middletown area, where O&R serves approximately 12,000 customers, is predominantly an older distribution system fed from two district regulator stations. To establish reliability and provide for load growth in an area that has been highlighted by Orange County as having substantial growth potential, O&R is planning a three-year reinforcement program from 2010 – 2012. In 2010, the Denton Hill district regulator station will be rebuilt and upsized at a cost of approximately \$500,000. The regulator station located on the property of O&R's Middletown propane plant will be rebuilt and upsized at a cost of approximately \$300,000 in Rate Year Two. Also in 2010, O&R will begin constructing two additional distribution projects. First, the Middletown Distribution Reinforcement – Genung to Golf Links Road of 16,000 feet of 12" plastic, 80 psig design

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO

1 distribution main will be installed between the Middletown Propane Plant
2 regulator station and the Denton Hill regulator station. This will allow either of
3 the two upgraded regulator stations to supply the total load of the Middletown
4 area in the event there is a failure of the other. This will cost an estimated \$1.5
5 million. In 2011, O&R will install 6,000 feet of 16", 250 psig design distribution
6 main from the Westtown – Warwick Loop to replace the existing feed to the
7 Middletown regulator station. This is estimated to cost approximately \$1.2
8 million. Additionally in 2011, the Company will begin a two-year project to
9 install 30,000 feet of 16", 250 psig design distribution main and a regulator
10 station from the Westtown – Warwick Loop to the northwest side of Middletown
11 at a total estimated cost of \$7.3 million, of which \$3.9 million will be expended in
12 2011. Also in 2011, O&R will install 30,000 feet of 12" plastic 80 psig design
13 distribution main at a total cost of approximately \$3.0 million. This pipe will
14 allow O&R to establish another source of supply to the remote corner of the high-
15 pressure grid and provide the opportunity for economic development in an area
16 that Orange County has designated as a priority growth area.

17 Lower Road – Wawayanda

18 In 2009, the Company will complete the installation of 40,000 feet of 20" 250
19 psig design distribution pipe along Lower Road in Wawayanda. In 2010, the
20 fabrication and installation of a Gate Station in Minisink will complete this
21 project.

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO

1 Rte 17A - Village of Florida

2 In 2009, the Company will complete the replacement of bare steel 250 psig design
3 distribution main operating above 125 psig in the Village of Florida. The
4 remaining 8,600 feet of this vintage pipe will be replaced with 16" wrapped steel
5 250 psig design distribution main on Rt 17A in Florida to the intersection of Rt
6 94.

7 Middletown to Bloomingburg Main Extension

8 In 2010, O&R will begin a three-year gas main extension project from
9 Middletown/Wallkill to Bloomingburg. The Company will install 30,000 feet of
10 12" 80 psig design plastic pipe along Route 17M and 5,000 feet of 12" 80 psig
11 design plastic pipe along Route 302. The total cost of the project is
12 approximately \$5.2 million, of which \$1.75 million will be expended in 2010.
13 Job creation in this area of Orange County is estimated to be between 1,000 to
14 3,000 jobs and will stimulate public and private investment in the area.
15 Completion of this project will extend the Company's gas service into Sullivan
16 County, which also has significant growth potential.

17 **System Reliability**

18 In reviewing the long term needs of the Orange and Rockland gas system it is
19 imperative for the integrity and reliability of the Company's system to continue to
20 eliminate radial mains, as well as to provide for the operability of valves on the
21 system which will allow the Company to isolate smaller areas quickly in the event
22 of an emergency.

**ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO**

1 Radial Main Elimination:

2 The Company has identified ten radial mains serving approximately 7,000
3 services, with not one radial main feeding fewer than 250 services. O&R will
4 establish a five-year program to eliminate these radials by installing additional
5 feeds into the areas identified. The total cost is approximately \$3.5 million, of
6 which \$2.75 million will be expended in 2010, 2011 and 2012, with the remainder
7 being expended in 2013 and 2014.

8 Secondary Valve Inspection Program:

9 In 2010, O&R will begin a secondary valve inspection program. Although
10 designated as secondary valves, they are often called upon for isolation in
11 emergency conditions to minimize the number of customers affected that would
12 otherwise be interrupted by a primary valve. Currently, O&R inspects
13 approximately 1,800 primary valves on an annual cycle, but does not have an
14 inspection program for the approximately 10,000 secondary valves on the system.
15 In 2010, O&R will begin a ten-year program to evaluate 1,000 secondary valves
16 per year for their inclusion in the secondary valve inspection program. As the
17 valves are identified and located, they will be inspected and placed in a ten-year
18 inspection cycle. Annual operations and maintenance (“O&M”) costs will be
19 approximately \$600,000 and will require incremental resources of two
20 troubleshooters and one supervisor to complete this additional work. Attachments
21 “A” and “B” provide supporting detail for these incremental resources.

22 **Q. Are there any other items you would like to address?**

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO

1 Yes. There are several other items I would like to discuss.

2 **System Contingency**

3 First, as O&R upgrades distribution pipe to 250 psig design piping in order to
4 fortify the distribution system backbone, the Company eliminates major lower
5 pressure distribution piping and therefore can lose significant pressures that could
6 impact customers on high demand days. To compensate for this, new 80 psig
7 design distribution lines are required. In the southeastern portion of Orange
8 County, O&R will upgrade the 12 and 16 inch distribution line from the Monroe
9 Regulator Station to the Cedar Cliff Regulator Station to 250 psig design pipe.

10 This is an important distribution feed and a number of distribution projects are
11 being planned to satisfy the pressure losses in this area when the 16 inch
12 distribution line is upgraded. Commencing in 2010, a total of approximately
13 15,000 feet of 6", 8", and 12" plastic will be installed over a three-year period at a
14 total cost of approximately \$2.6 million, of which \$1.8 million will be expended
15 in 2010. Second, through contingency analysis, the Company has identified that
16 the West Nyack Regulator Station as a critical station. Its central location in
17 Rockland County makes it a work horse for the system. If the Company were to
18 lose this station during peak times, other regulator stations need to pick up the
19 loads. This would require crews to respond to the other adjacent regulator
20 stations to readjust the regulators for higher outlet pressures. In 2010, the
21 Company will upgrade several local distribution systems to handle the loads from
22 these adjacent regulator stations without having to dispatch crews to manually

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO

1 adjust pressures under emergency conditions. To eliminate this operational risk,
2 O&R will install 7,500 feet of 6” and 12” plastic at four locations at a total cost of
3 approximately \$1.5 million over three years beginning in 2010.

4 Unanticipated Contingencies

5 Unforeseen contingencies including major floods, large area outages such as the
6 loss of gas service to 1400 customers in Greenwood Lake, and major third party
7 infrastructure programs such as Verizon’s installation of its broadband Internet
8 access system (*i.e.*, FIOS), have caused significant unexpected operational
9 expenses for the Company that cannot be avoided. Our experience demonstrates
10 that these types of unforeseen contingencies occur with regularity and impose
11 significant incremental costs on the Company’s gas operations. The Company’s
12 operating priorities, however, are not flexible enough (*i.e.*, there is not sufficient
13 work that can be rescheduled, repositioned, or otherwise avoided) to allow
14 Orange and Rockland to maintain operations and meet these various recurring
15 contingencies. To address this situation, the Company will establish a \$500,000
16 contingency fund to be used for those unexpected individual situations where
17 costs exceed \$200,000. Monies unspent at the end of the rate plan will be
18 deferred for the benefit of customers.

19 Operational Improvements

20 Computer Dispatch

21 Over the past five years, O&R has spent approximately \$5 million implementing
22 a functional computer aided dispatch system for Gas Operations. This system has

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO

1 proven to be extremely robust and has allowed the Company to meet its PSC Leak
2 Response Safety mandate of 75% of leak calls within 30 minutes not merely by
3 increasing headcount but through operational improvements like Computer
4 Dispatch. The next phase of implementation is to integrate the wireless dispatch
5 system into the areas of leak repairs for maintenance crews, and periodic
6 inspection and leak management for service crews. In the three years covered by
7 the Company's proposed rate plan, the Company estimates that another \$1.9
8 million will be spent to accomplish this increased functionality. Specifically, the
9 Company will spend \$355,000 in the Rate Year, \$747,000 in the year ending
10 October 31, 2011, and \$751,000 for the year ending October 31, 2012. In the
11 payroll exhibit, the Company includes the elimination of a Senior Operations
12 Coordinator, which is a direct result of this increased functionality. The Company
13 has demonstrated its full commitment to computer aided dispatch and other
14 opportunities to enhance productivity through process changes and technology
15 improvements. Although these improvements provide short-term improvements,
16 some also lead to longer-term benefits and functionality that continually improve
17 gas safety and customer response and justify its inclusion in rate base.

18 Remote Operated Valves

19 As part of the Company's current gas rate plan, O&R is committed to installing at
20 least one remote operated valve ("ROV") per year on its system between 2003
21 and 2008. With the successful installation of nine ROVs already, the Company
22 will continue the installation of a minimum of one ROV per year on its 250 psig

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO

1 system over the next 15 years, with the goal of being able to isolate any section of
2 the 250 psig system through supervisory control, without loss of supply to any
3 district regulator supplied from that system. The annual cost of these installations
4 is estimated to be \$325,000 (one ROV per year).

5 Automated Meter Reading (AMR)

6 AMR has shown success in reducing estimated readings thereby improving
7 customer satisfaction by providing accurate bills to our customers. The Company
8 will continue its effort of installing AMR devices on meters that are difficult to
9 access and/or are situated in unsafe/hazardous locations. AMR costs are included
10 in the Gas Blanket spending for a total of \$934,000. Specifically, the Company
11 will spend \$282,000 in the Rate Year, \$352,500 in the year ending October 31,
12 2011, and \$299,800 for the year ending October 31, 2012.

13 **Q. Are there other operational improvements that O&R proposes to**
14 **implement?**

15 A. Yes. Since the Company's 2006 gas rate case, the need for a gas standards
16 engineer has increased. There is a significantly heightened need and limited
17 resources to address the various programs established in the Company's current
18 gas rate plan such as transmission main redundancy, additional distribution main
19 replacement, secondary valves, and proposed regulations for distribution integrity
20 management. It also requires the Company to split standards and procedure work
21 among all the current engineers in the group rather than have this key
22 responsibility concentrated under one person. Thus the establishment of new

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO

1 standards and procedures and their updates is not as robust as needed, consistency
2 in format and thoroughness is lacking, field input has not been optimized,
3 benchmarking of other utilities is minimal, and new technologies or improved
4 system components are not being rigorously pursued. For these reasons, the
5 Company will establish this additional engineering position. Attachment “C”
6 provides additional supporting detail for this incremental engineering resource.
7 Since the 2006 gas rate case, the need for an additional engineer to identify and
8 oversee projects has become a pressing need. While the number of projects that
9 O&R has undertaken has increased moderately, the coordination and planning
10 with the various municipalities and agencies has become increasingly time-
11 consuming. Project engineers are required to attend various Town and Planning
12 Board meetings to present the proposed projects and follow-up with walk-
13 throughs and site visits prior to receiving road opening and environmental
14 permits. As this process has become more complicated by agency approvals, it
15 has detracted from the time needed for engineers to spend on core engineering
16 activities such as maintaining an emphasis on evaluating system reliability,
17 targeting mains for replacement and providing the necessary field oversight
18 during construction. Attachment “D” provides additional supporting detail for
19 this incremental engineering resource.
20 Additionally, the Company has identified the need for an engineering coordinator
21 to support the administrative details and duties that are involved with the various
22 projects in the Gas Engineering Department. The number of projects requiring

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DIRECT TESTIMONY OF
RICHARD S. DI LORETO

1 State Environmental Quality Reviews (“SEQRs”), Article VII reviews, scaled
2 land surveys, and easement acquisitions, has increased dramatically, and the
3 amount of coordination and work involved with these projects and permitting
4 approvals has significantly impacted the Gas Engineering Department. This
5 coordinator will handle routine administrative tasks and thereby allow the
6 Company’s engineers to focus more on core engineering needs. Attachment “E”
7 provides additional supporting detail for this incremental engineering coordinator
8 resource.

9 **Q. Please continue.**

10 A. The volume of main replacement and installation work being performed in
11 O&R’s service territory has grown considerably in the past five years. To
12 complete this capital main replacement and installation work in a timely and
13 effective manner, O&R utilizes the services of several trained and qualified local
14 contractors. O&R’s Contract Administration Group (“CAG”) is responsible for
15 providing the proper contractor oversight so that the work is being performed as
16 engineered and as per Company specifications, as well as assuring that O&R is
17 billed accurately. Currently, the Company’s construction inspectors are
18 responsible for preparing the projects for bid, closing out projects as they are
19 completed and following up so that bills have been processed for payment. This
20 office work occupies 35 – 40% of their time and detracts from their most
21 important field responsibilities of supervising field inspectors and the work being
22 done by contractors. In order to continue to provide daily and consistent

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO

1 oversight, the Company is seeking additional support in the CAG area, in the
2 form of a planner and an administrative support analyst. This will allow the
3 construction inspectors to spend more time in the field, provide improved
4 oversight to the project, and better communicate with the customers affected by
5 the work. Attachments “F” and “G” provides additional supporting detail for
6 these incremental CAG resources.

7 Presently, Orange and Rockland has five Gas Service Operators and five
8 Distribution Supervisors that oversee the distribution system in the Gas
9 Distribution Control Center (“GDCC”). The current staffing allows minimal
10 around the clock coverage on each shift. With the expanded use of Gas Mobile
11 Dispatch, the GDCC staff, in addition to their normal responsibilities for
12 monitoring and dispatching field crews to emergencies, will now also be
13 responsible for managing and assigning short interval task (“SIT”) work, (*e.g.*,
14 valve inspections), to enhance productivity on a routine basis. O&R plans to
15 have the GDCC staff manage the dispatch function for the Locating Department.
16 In addition, the GDCC will assume the responsibility to review, approve, and
17 monitor gas main “cut-out” and “tie-in” procedures to provide consistency,
18 efficiency and oversight to the process. To support these additional
19 responsibilities, as well as allow for required annual training and shift coverage,
20 O&R will increase the staffing in the GDCC by one Service Operator and one Gas
21 Distribution Supervisor. Attachment “H” provides additional supporting detail
22 for these incremental GDCC resources.

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO

1 In addition, to provide administrative support for O&R's GDCC and Locating
2 groups, the Company will add additional support in the GDCC in the form of one
3 administrative clerk. The GDCC and Locating Groups presently have a total of
4 18 union and 7 management positions with no administrative support. Their
5 administrative support activities have historically been divided among the various
6 Operations Support groups throughout the organization. As both groups are being
7 consolidated, and the number of employees and workload in both organizations
8 increase, it is essential that administrative support be provided within the GDCC
9 staff. Attachment "I" provides additional supporting detail for this incremental
10 administrative position.

11 Although O&R continues to improve in the area of damage prevention, the
12 Company still lags statistically if compared to other New York State utilities in
13 terms of measureable performance. One of the reasons was the turnover of
14 personnel performing the locating function. The Company's agreement with its
15 Union, which includes a four-year "lock in" of new Locators, dramatically
16 moderated the turnover rate. This allowed the Company to retain a more
17 experienced workforce which resulted in more accurate mark outs. The Company
18 is experiencing an increase in the number of one-call tickets primarily due to the
19 amount of excavating work being performed by Verizon and other municipal
20 contractors performing mass infrastructure work. In an effort to improve our
21 performance in this area as well as keep up with the additional ticket volume,
22 O&R will purchase a hydro-vac truck to perform more vacuum excavation for the

**ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO**

1 difficult to locate facilities, as well as to field verify mapping discrepancies. This
2 method of excavation is much more efficient, acceptable and productive and will
3 allow more test hole verifications to be done where instrumentation is not
4 accurate. As a result, O&R will increase staffing of union Locators by two to
5 support the utilization of the truck, as well as the significant increase in Locating
6 workload. Attachment "J" provides additional supporting detail for these
7 incremental Locating resources.

8 Gas Construction routinely works into the second shift and beyond to complete
9 planned and emergency work and supervision is provided by various operating
10 supervisors. Gas Operations will implement a routine second shift for
11 construction supervisors specifically to provide oversight to these extended
12 construction crews. The Company will increase the staffing in the gas
13 construction area by two supervisors, and this would eliminate the need for
14 supervisors from other disciplines to fill in as construction supervisors, thereby
15 improving efficiency and oversight for construction activities on all shifts.

16 Attachment "L" provides additional supporting detail for these incremental
17 construction resources.

18 **Q. Will these operational improvements allow the Company to continue its**
19 **efforts to become more operationally efficient?**

20 A. Yes. As noted above, the Company continues to implement a variety of
21 technology and process improvements that have enhanced the Company's
22 efficiency and productivity. Events are reviewed for lessons learned,

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO

1 management seeks out best practices throughout the industry, and actions are
2 taken to achieve gains. The implementation of a computer dispatch system for
3 Gas Operations has improved the Company's leak response performance, without
4 adding additional personnel, and allowed for the elimination of a Senior
5 Operations Coordinator. The continued expansion of the computer dispatch
6 system to maintenance and service crews, and integrating it with inspection and
7 maintenance data will produce additional benefits. The Company has worked
8 with its Union to produce efficiencies, such as the four-year "lock-in" of new
9 Locators, as described above. Additionally, the Company's introduction of
10 additional shifts for both management and union, has improved our ability to
11 manage overtime more effectively. The addition of a Gas Standards Engineer
12 will allow for the establishment of updated, uniform standards and procedures that
13 should help streamline the Company's gas operations. Moreover, the addition of
14 a Gas Projects Engineer will allow the Company to deal more effectively with an
15 ever more extensive and complicated array of state and local regulatory
16 requirements, and provide more effective project oversight.

17 The addition of a planner and analyst in the CAG group will improve contractor
18 oversight as this will allow CCIs to spend more time in the field directing
19 contractor inspectors and contractor crews to increase productivity and decrease
20 downtime.

21 The additional positions requested in construction to perform the additional
22 30,000' of main replacement will improve productivity as field forces retain and

**ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO**

1 increase their knowledge and field experience. Capital tools will be more readily
2 available thereby decreasing downtime, and paving required after repairs will be
3 completed in a more expeditious manner resulting in increased customer
4 satisfaction.

5 Overall, the programs and resource additions described above focus on better
6 utilizing the workforce skills and equipment, maximizing the use of data and
7 making it readily available, and continuing to examine opportunities to improve
8 processes and work flows. These guide compliance and allow the Company to
9 achieve routine productivity improvements while enhancing safety and customer
10 service.

11 **Performance Metrics**

12 **Q. Is the Company proposing any performance mechanisms as part of this rate**
13 **case?**

14 A. No. O&R focuses on providing superior performance and does not require
15 performance mechanisms to achieve such superior performance. Furthermore,
16 penalties are negative and are a poor substitute for constructive regulation.

17 **Q. If the Commission decides to continue performance mechanisms for the**
18 **Company, does the Company have a view as to how they should be**
19 **structured?**

20 A. Yes. If the Commission concludes that it is necessary to continue performance
21 mechanisms for Gas Operations, O&R would propose the following four
22 performance measures:

**ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO**

- Leak Management;
- Emergency Gas Odor Response;
- Damage Prevention; and
- Main Replacement.

Specific performance targets would be established for each measure as identified below. The Company is not proposing in this testimony to reduce the penalty levels currently associated with these performance targets. This is solely to minimize controversy. For Leak Management, O&R proposes that the measure be the attainment of a calendar-year end level of 30 workable gas leaks (Type 1, 2A and 2) or less for each year of the rate plan.

For Emergency Gas Odor Response, O&R proposes the measure be the attainment of a response to 75% of all emergency odor calls within 30 minutes.

For damage prevention, O&R proposes three measures; (1) total damages/1000 one-call tickets to be 6.25 or less for each year of the rate plan, (2) mismarks/1000 one-call tickets to be 1.25 or less for each year of the rate plan, and (3) damages by Company/Company contractors/1000 one-call tickets to be 1.25 damages or less in each year of the rate plan, where Company/Company contractor crews are defined as Company gas forces and Company gas contractors.

For main replacement, O&R proposes the measure to be the replacement of 330,000 feet of main over the three years, with no less than 80,000 feet in any given year and no less than 7,500 feet of cast iron each year, no less than 30,000

**ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO**

1 feet of bare or inadequately protected steel each year, and no less than 35,000 feet
2 of Aldyl plastic each year.

3 Currently capital main replacement and installation work is performed primarily
4 by qualified contractors. The incremental 30,000 feet average per year (*i.e.*,
5 increase of 240,000 feet to 330,000 feet over three years, which amounts to an
6 annual average of 30,000 additional feet O&R is planning to install. This will be
7 performed primarily by Company crews. The total incremental costs to perform
8 this additional footage will be approximately \$1.8 million each year. This will
9 require the addition of eight gas fitters; four each in 2010 and 2011. The benefits
10 of performing this work with Company forces include maintaining core
11 construction skills in a workforce that currently is involved primarily in
12 maintenance activity, and allocating resources to this important capital program in
13 an environment of limited qualified contractors. An additional highway
14 repairman also will be required to provide support to the additional field forces
15 with the removal of excavated spoil and delivery of backfill material; as well as
16 road restoration for these replacement projects. To support these projects and the
17 equipment that is utilized, O&R also plans to add a tool room mechanic to
18 manage the inventory of specialty tools and tapping equipment utilized by
19 company construction crews. The person would be responsible to perform
20 maintenance and repair of equipment as well as compile and maintain electronic
21 repair logs of inventory and orders. In order to properly manage and supervise
22 the incremental 30,000 feet per year of main replacement, two additional

**ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO**

1 supervisors, one in the Eastern Division and one in the Northern Division, will be
2 required in 2010. The Company's current supervisory levels cannot adequately
3 cover this increased level of construction activity, particularly in a climate where
4 municipal permitting, specifications, oversight and inspections have significantly
5 increased over the years. Attachments "M", "N", "O", and "P" provides
6 additional supporting detail for these incremental Construction resources.

7 **Q. Please summarize the total number of incremental employees that you are**
8 **proposing to add in this rate case.**

9 A. I am proposing that O&R add 26 incremental employees, as set forth below that
10 will be phased in over a three-year period. Please refer to the testimony of
11 Company witness Kosior for the costs applicable to each period.

12 1) Gas Service – (2) Troubleshooters, (1) Supervisor

13 2) Gas Engineering – (2) Engineers, (1) Coordinator

14 3) Contract Administration – (1) Planner, (1) Analyst

15 4) Gas Control Center – (1) Supervisor, (1) Dispatcher

16 5) Locating – (2) Locators

17 6) Clerical – (1) Locating/Control Center Clerk

18 7) Gas Construction – (2) Supervisors

19 8) Capital Construction – (8) Fitters, (1) Highway, (1) Tool Room, (2)
20 Supervisors

21 9) Senior Operator Coordinator attrition savings in one position

**ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO**

1 NOTE: Attachments “A” through “P” provide the supporting detail for these
2 positions.

3 **Q. Please continue.**

4 A. Although we are not proposing to reduce the penalty levels associated with the
5 Commission’s metrics, we believe a provision permitting the Company to obtain a
6 waiver of a penalty if the results were outside the Company’s reasonable control
7 should be added. This is in line with the principle that penalties are inappropriate
8 for conduct not shown to be unreasonable.

9 **CNG Pilot Program**

10 **Q. Please discuss the Company’s proposed CNG pilot program.**

11 A. The Company expects that with the increased availability of domestic natural gas,
12 CNG-fueled vehicles will become a more viable economic choice. In pursuit of
13 their goals to lower carbon emissions and reduce the Nation’s dependence on
14 foreign oil, federal and state governments are expected to increase their support of
15 these vehicles. With the recent commercialization of a home fueling appliance,
16 Honda, presently the only auto maker of CNG-powered vehicles, plans to double
17 their production for the United States market in 2009. Additionally, other auto
18 manufacturers are conceptually designing CNG-electric hybrid vehicles.
19 Encouraging natural gas as an alternative transportation fuel for commuters and
20 operators of vehicle fleets can provide an opportunity for O&R to utilize its
21 delivery system to support home fueling while at the same time, demonstrating
22 that it is serious about offering alternative solutions to meet present and future

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO

1 energy and environmental challenges. A CNG vehicle is much cleaner-burning
2 than one that runs on gasoline. According to the EPA, CNG can reduce carbon-
3 monoxide emissions by 90 to 97 percent and nitrogen-oxide emissions by 35 to 60
4 percent when compared with gasoline. CNG can also potentially reduce non-
5 methane hydrocarbon emissions by 50 to 75 percent, while producing fewer
6 carcinogenic pollutants and little or no particulate matter. And natural gas is more
7 than 20% better for carbon dioxide emissions, blamed for climate change, than
8 comparable gasoline engines.

9 **Q. Please continue.**

10 A. Until recently, growth in the consumer market for CNG-powered vehicles was
11 stymied by the scarcity of refueling stations. However, with the advent of a home
12 fueling appliance, CNG-powered passenger cars are now a viable alternative for
13 commuters. O&R's service territory has a large commuter population that is ideal
14 for a home fueling market. We estimate that as many as 42,000 of O&R's natural
15 gas customers commute to work outside of the counties they live in, and the vast
16 majority of these customers commute within the 100 mile limit that would allow
17 for overnight residential refueling. The cost of CNG can be less than half that of
18 gasoline when using a home refueling device. Moreover, when prices for
19 gasoline spiked to over \$4.00 per gallon over the summer, demand for alternative
20 fuel vehicles surged.

21 **Q. Are there currently any governmental incentives for CNG vehicles?**

**ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO**

1 A. The federal government currently offers a tax credit of \$4,000 for buyers of the
2 Honda Civic GX. Additionally, there is a \$1,000 federal tax incentive available
3 toward the cost of the home fueling appliance, which is approximately \$3,400.

4 **Q. Please describe the incentives that the Company is proposing for CNG home**
5 **fueling appliances?**

6 A. The Company is proposing to provide a financing incentive for the installation of
7 CNG home fueling appliances. Specifically, O&R proposes a \$1,000 incentive
8 toward the purchase and installation of the unit. This incentive will be available
9 to the first 150 applicants during the Company's three-year gas rate plan.

10 **Q. Does the Company plan to implement a special rate for participants in the**
11 **CNG pilot program?**

12 A. No. As discussed by the Gas Rate Panel, the Company plans to use its existing
13 rate structure for this pilot program.

14 **Q. Please describe the Company's plan to market this pilot program.**

15 A. O&R plans to spend approximately \$20,000 per rate year on advertising to
16 promote the program and the benefits of CNG vehicles to the community.

17 **Interruptible Customers – Service Classification 8**

18 **Q. Please discuss the operating benefits associated with the Company's SC 8**
19 **rate.**

20 A. Interruptible transportation customers taking service under SC 8 currently provide
21 limited benefit to the Company in the operation of its transmission and

**ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO**

1 distribution systems. From an operating perspective, the SC 8 rate no longer
2 provides the Company with the benefits for which it was originally designed.

3 **Q. Please elaborate.**

4 A. Prior to the Federal Energy Regulatory Commission's ("FERC") issuance of
5 Order 636, interruptible customers taking service under Service Classification No.
6 3, Interruptible Sales ("SC 3"), received all of their gas from O&R. SC 3
7 provided significant benefits to O&R's firm customers, since during periods of
8 interruption of SC 3 customers, up to 25,000 thousand cubic feet/day ("mcf") of
9 firm supply would become available to firm customers. The subsequent
10 unbundling of services and the removal of the merchant function from the
11 delivery pipelines allowed customers to pursue other supply options and to have
12 their respective deliveries transported to O&R City Gates on their behalf. O&R's
13 SC-8 rate, which provides transportation service from the City Gate to the
14 customer's location, was initiated to provide this service.

15 In order to help provide reliable service to firm customers, O&R would shed
16 interruptible load when its piping system reached capacity limitations.

17 Historically this would be on the coldest days of the year. However, based on the
18 current configuration of O&R's gas distribution system, O&R no longer needs to
19 interrupt SC 8 customers, even on a projected peak day. I would note that over
20 the eight-year period ending October of 2008, O&R's SC 8 customers have not
21 been interrupted due to distribution system limitations. Thus, this class of
22 customer is effectively receiving firm service at a much reduced rate.

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO

1 Of the 92 current SC 8 customers, most are relatively small (*i.e.*, 66 are below 10
2 mcfh), and individually do not provide a significant improvement to pressure
3 when interrupted.

4 In addition, O&R has been implementing distribution reliability programs which
5 will allow the Company to provide service to firm customers in the event of gas
6 delivery contingencies, including consequences of third-party damage, or facility
7 failure. To a large extent, the need for reliability programs has been due to the
8 radial feed configuration of systems, and isolated pocket growth over the years
9 within the franchise area. Recent construction efforts are reducing the number of
10 customers who are exposed to loss of service as a result of a single contingency.
11 However, the result of such programs also serves to improve system pressures
12 during normal operating conditions, and further reduces the likelihood an
13 interruption being required.

14 **Q. Based on the foregoing discussion, what is your proposal regarding the**
15 **Company's SC 8 interruptible transportation service?**

16 A. I am proposing to close SC-8 to new customers effective November 1, 2009.

17 **Q. Do you have a proposal regarding the existing customers taking service**
18 **under SC 8?**

19 A. Not at this time. The Company is willing to explore with Staff and other
20 interested parties as to how SC 8 will be continued, modified and/or eliminated in
21 the future.

22 **Q. Does that conclude your testimony?**

**ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO**

1 A. Yes, it does.

**ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO**

Attachment A

Gas Troubleshooters (2):

Purpose:

Adding two Troubleshooter positions allows the Company to supplement and enhance our existing primary valve inspection program and allows additional support for the proposed secondary valve inspection program. Per our current bidding process, these positions initially would be filled as Apprentice Troubleshooters, where valve inspections can be assigned on a steady basis with other tasks to help develop the apprentice to a fully qualified Troubleshooter 1st Class.

Major Responsibilities:

- Perform primary / secondary valve inspections.
- Adjust valve boxes behind the curb or in non-paved areas.
- Complete Gas Mobile Dispatch (“GMD”) templates for inspections.
- Submit mapping corrections properly for correction, taking verifying field measurements.
- Perform other assigned tasks as an apprentice, such as:
 1. Piping work on meter relocations;
 2. Leak rechecks;
 3. Shared meter and mixed meter investigations; and
 4. Flagging.
- Ride with other Gas Troubleshooters to gain full on the job training necessary to become a Troubleshooter 1st class.

**ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO**

Attachment B

Gas Service Supervisor (1):

Purpose:

Currently in the Gas Service Department in the Eastern Division, the Company has 25 Gas Servicemen/ Troubleshooters that are scheduled across two shifts (Mon –Sat) that are managed by two supervisors. Adding this position would allow the Company to schedule a supervisor on the evening shift. Currently on the evening shift, other supervisors from different disciplines, on a rotating standby schedule, fill-in on an as needed basis.

Adding additional supervision would allow O&R to separate disciplines and provide more effective oversight of the crews and work. Also, during the day shift, when a supervisor is out on vacation, sick, or in training, the additional supervisor would allow the Company to staff effectively.

Responsibilities:

- Work under the current planner and work the evening shift to supervise 5-7 crews.
Fill-in on day shift as needed.
- Manage work distribution and completion of periodic inspections, rechecks, and relocation work.
- Respond to odor calls on the evening shift.
- Handle customer appointments for meter relocations, pool heater inspections, and general inquiries in the evening to enhance customer satisfaction.
- Review leak sheets from prior day's shifts and prepare work for next day.
- Troubleshoot GMD and mobile computer issues.

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO

- Perform vehicle accident investigations.
- Manage the primary / secondary valve program by coordinating mapping corrections sent to mapping, and follow-up work orders sent to Gas Construction for completion.
- Hold standby supervision slot in a rotation for non-shift (*i.e.*, midnight shift and weekend) emergency coverage to respond to emergencies and odor calls.

**ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO**

Attachment C

Gas Engineer (Standards/Procedures)(1):

Purpose:

The purpose of this position is to coordinate and lead O&R's standards and procedures work as described below.

Responsibilities:

- Annual review of Gas Work Procedures:
 1. More in depth office review of procedures;
 2. Field reviews with crews to identify procedure deficiencies (currently not systematically performed); and
 3. Annual review of Standards and the Gas Supervisor Operating Manual (GSOM).
- Gas Department representative on Gas Emergency Operating Procedure ("GEOP") issues to allow for enhanced management of same.
- Benchmark existing and proposed procedures and standards relative to others in the industry.
- Evaluate suggested changes to existing procedures and standards from field and office personnel and determine the appropriateness of the suggestion. Report results to the Standards Committee, as well as the individual making the suggestions. Would provide a "one stop shopping" resource for Gas Operations personnel.
- Maintain industry and utility contacts so as to remain current with possible material and process changes that could enhance existing procedure and standards. Includes

**ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO**

representation on American Gas Association (“AGA”) best practices

committees/workshops to increase Company exposure to industry developments.

- Material testing and product failure evaluations. Oversee new product “trial and evaluation” procedures and field surveys.
- Maintain the GEOP.
- Chair the Standards Committee.
- Communicate with Compliance Specialist on need for new or revised procedures based on audit findings.

**ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO**

Attachment D

Gas Engineer (Projects)(1):

Purpose:

Identify, plan, design, engineer, and implement activities associated with gas pipeline distribution and transmission construction projects. These projects encompass, but are not limited to, system reliability, pressure reinforcement, gas expansion for new growth, and gas relocation required for municipal or public improvement projects.

Responsibilities:

- Work with the engineering planners to identify system improvement projects that will enhance reinforcement and reliability.
- Conduct cost justifications and cost benefit analyses.
- Prepare purchasing and work order requisitions for material and equipment needed to conduct the project, and for retention of construction contractors, and engineering and design firms. Perform all other required paperwork and budgetary information for project approval within the company.
- Prepare bid packages for work being let out to gas contract forces. Organize and run bid meetings.
- Retain and interface with engineering consulting firms who help prepare the project scaled drawings based on town, village, county, state and federal codes and regulations and other requirements.
- Contact and work with the various municipal and government agencies that might be affected by the project. Create, obtain and/or prepare all necessary information

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO

required by the agencies in order to receive their approvals to conduct the project and acquire the environmental and road opening permits.

- Work with various environmental agencies to obtain permits (*e.g.*, New York State Department of Environmental Conservation (“NYSDEC”), Drainage Agencies, and Army Corp of Engineers)
- Plan pipeline route with municipalities and other interested parties (*e.g.*, NYSDEC, NYPSC). This will require numerous field visits and meetings with the municipalities and engineering design consulting firm.
- Attend Planning Board, Town Board and Public Town Hall meetings as necessary to receive project approval.
- Communicate with internal departments within the Company to inform them of project initiation and progress, and /or work with them when necessary to alleviate duplication of services, (*e.g.*, New Business, Public Affairs, Community Relations, Environmental, Real Estate, and Gas & Electric Operations).
- Provide oversight of field crews performing the work, including assigned Company Inspectors, Company crews and Contractor crews; and provide construction and engineering guidance throughout the life of the project.
- Manage and keep track of field construction activities.
- Review and approve invoicing.

**ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO**

Attachment E

Gas Engineering Coordinator (1):

Purpose:

- Maintain office administrative functions (*e.g.*, office equipment, supplies, Iron Mountain storage, and photocopying).
- Assist Gas Engineers with the administrative details that are involved with:
 1. Obtaining project approvals (*e.g.*, Work Management System (“WMS”), Quik Reqs (*i.e.*, the Purchasing Department’s Electronic Database), Capital Funding Requests, and permitting);
 2. Administering the projects (*e.g.*, budgeting, invoicing, communication with vendors, and various agencies); and
 3. Closing projects out (WMS, record keeping, filing, and mapping).

There will be other miscellaneous assignments for which the Coordinator’s assistance will be requested (*e.g.*, coordination of training seminars)

Maintain files and records as they relate to new gas pipeline installations as well as the replacement and retirement of leaking and/or redundant gas pipelines. Act as the contact person for the transference and retrieval of records from “Iron Mountain”. The individual will assist Gas Engineers in the creation of layouts for work, and coordinate the ordering of material and supplies for the organization. Additionally, the person will monitor the training requirements for the group and schedule classes when necessary.

**ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO**

Responsibilities

- Prepare and track Quik Reqs;
- Prepare and closeout WMS;
- Verify that the final NRG mapping is consistent with the “as built” drawing;
- Assist Contract Administration Group (“CAG”) with coordination of the monthly Living Budget;
- Coordinate Accruals for Engineering Projects;
- Address invoice inquiries;
- Prepare Capital Funding Requests based on input from Engineers; and
- Prepare and update project schedules based on input from Engineers.

Attachment F

- 39

**ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO**

- Review tie-in procedures with CCI prior to work being performed.
- Periodically review main replacement list with Gas Engineering and prepare bid packages.
- Verify the compliance of direct reports to Company policies and procedures as they relate to gas main and service installation and replacement.
- Complete the “Field Observation Reports” for each project and entered into the Contractor Oversight System (“COS”).
- Work with Purchasing to evaluate contractor bids.
- Perform other related assignments as required.

**ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO**

Attachment G

CAG Administrative Support Analyst (1):

Purpose:

Administer budget oversight, provide assistance to the manager during the bid process and review billing prior to manager approval so that field documentation is accurate and complete.

Responsibilities:

- Prepare, analyze and develop monthly and year-to-date budget expenditures and variance reports.
- Prepare monthly accruals for work completed by contractors but not yet paid.
- Prepare Capital Funding requests for work planned and estimated over \$50,000.
- Prepare Capital Funding Supplements for work completed over or under the 15% allowance.
- Analyze, review and communicate actual performance, historical comparisons, and annual expenditure projections.
- Assist in the preparation and development of the Department's capital forecast including working estimates for on-going projects.
- Administer the Contractor Oversight System for the Department and provide assistance to Chief Construction Inspectors and Field Inspectors as required.
- Analyze, review and validate invoices submitted for payment by contractors so that accurate and timely payment for work performed.

**ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO**

- Analyze, review and validate “Daily Inspection” sheets so that “extra” work identified for payment has been properly documented and approved, when necessary, prior to approval for payment.
- Review and monitor daily mileage and overtime sheets to verify accurate reporting by Field Inspectors and Chief Construction Inspectors.
- Coordinate all contractor Health and Safety Plans (“HASP”) and contractor accident investigation reports.
- Maintain required records and reports for inspection by Company auditors and associated agencies.

**ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO**

Attachment H

Gas Distribution Supervisor (1) & Service Operator (1):

Purpose:

The addition of two new positions in the Gas Distribution Control Center (“GDCC”) will primarily provide for increased coverage during the busiest times of the day. It also will provide for increased flexibility for training, and will support the additional workload requirements resulting from the computerization of all Short Interval Tasks (i.e., valves, Buildings of Public Assembly (“BOPA”) and red tag re-inspections) for the Gas Troubleshooters and the implementation of a secondary valve program. Finally, in 2009, the GDCC will be assuming the responsibility of dispatching Company locators to both emergency and non-emergency work.

Responsibilities:

- Manage the activities of Gas Troubleshooters and Gas Appliance Servicers so as to provide for the timely, efficient routing of both emergency work and scheduled maintenance work.
- Review and develop gas tie-in procedures and contingency cases, and implement as required.
- Utilize existing information and interact with field personnel to determine the best method to operate, maintain, and restore the gas distribution and/or transmission system.
- Review and approve all transmission, multi-primary and radial feed valve inspections.
- Initiate and finalize all billing jobs associated with gas damages.

**ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO**

- Provide that initial mandated notifications to Regulatory Agencies are made in a timely and accurate manner, as well as notifications to Corporate and Gas Operations Management.
- Document all gas incidents and follow up with Gas Operations' field personnel to verify the accuracy of the information.
- Review all the Transmission Line Activity Reports and verify that the identified valves have been inspected.
- Review Gas Standards and Procedures and make recommendations to the Standards and Procedures Committee as necessary.

**ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO**

Attachment I

Operations Coordinator – GDCC & Locating (1)

Purpose:

Presently, the O&R Gas Distribution Control Center and Locating groups have a total of 18 union and 7 management positions with no administrative support. Their duties and responsibilities have been divided among various Operations Support groups in the service territory. As the responsibilities and number of employees in both organizations increase, it is becoming essential that it be managed centrally.

The addition of this position will allow us to better manage the clerical requirements for both organizations and allow the supervisors to concentrate on their day-to-day activities.

Responsibilities:

• Prepare and process the GDCC and Locating time sheets and update employee records for both Management and Union employees.

- Assist in performing routine computations, tabulations and analysis of departmental data.
- Create and update files in all appropriate Company systems so as to provide proper record keeping and regulatory compliance.
- Responsible for the preparation of the “standby list” for the department.
- Track employee sick and vacation time so as to comply with the Company guidelines.
- Handle telephone calls from both internal and external customers.

**ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO**

- Perform general clerical duties as required such as; maintain inventory, type letters, filing of all departmental reports and making appointments.

**ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO**

Attachment J

Gas Operations Locator (2):

Purpose:

With the demands of Code 753 deadlines, O&R would benefit from the use of a Hydro-Vac truck as it significantly cuts down “hard to locate” time. O&R will be purchasing a Hydro-Vac truck in late 2008/early 2009 since the equipment is considerably more efficient than its current vacuum excavation truck. In order to properly use the equipment, O&R would require an additional two Locators. Increased efficiencies of both manpower and equipment will be critical because of the anticipation of increased mark-out volume due to Verizon’s fiber optic cable installation and municipal projects in Rockland County. We anticipate that this increased work volume will continue for the next two to three years, putting the need to reduce damages from this work in the forefront; and responding to more “hard to locate” requests more imperative and timely.

In addition, the Locating Department responds to mapping discrepancies identified by our Mapping Department, or found during previous mark-outs, and various inspections. The Hydro-Vac will allow us to reduce and manage the mapping correction backlog by being able to verify facilities and make the mapping corrections sooner. The Hydro-Vac is also versatile as it can be used in other applications within Gas Operations, *i.e.*, digging smaller excavations in gate stations, deep valve box repairs, assisting in gas damages to dig quicker safe holes (some cases without having to shut electric if it is a combination trench).

**ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO**

Responsibilities:

1. Perform locations of gas and underground electric facilities.
2. Perform pipeline integrity inspections.
3. Coordinate “assist-work” with other Departments within Gas Operations
(Cathodic Protection, Gas Engineering, Gas Construction, Gas Maintenance), as
needed.
4. Take slot in standby rotation for after hour emergency mark-outs.
5. Work an 11 - 7 shift to offset some of the overtime costs.

**ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO**

Attachment K

Gas Construction Supervisors (2):

Purpose:

Presently O&R has three gas construction supervisors in the Eastern Division that report directly to a Planner who oversees gas construction and gas maintenance functions on a daily basis. After hour coverage is managed through the use of supervisors on a rotating schedule also utilizing supervisors from other disciplines other than gas construction. These two additional supervisors would allow for regular coverage of a second shift without the use of supervision from other departments.

Responsibilities:

- 1) Perform duties as second shift supervisor.
- 2) Plan, organize, schedule and direct personnel engaged in regular and emergency maintenance, operation and inspection of gas facilities.
- 3) Supervises, including disciplining, training and developing employees in conformity with Company policy, labor agreements, safety priorities and other matters to maintain efficient productivity.
- 4) Work closely with all other departments to insure coordination, cooperation and service to customers and the public within established corporate and regulatory goals.
- 5) Manage planning and setup of main/service replacements.
- 6) Oversee planning and implementation of capital main replacement projects.
- 7) Set up and oversight of valve maintenance/replacement projects.

**ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO**

- 8) Write and close WMS projects.
- 9) Respond as necessary for emergency leak coverage after hours.
- 10) Review daily logs and time sheets for accuracy.
- 11) Set up daily log sheets for next day's crews.

**ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO**

Attachment L

Gas Fitter (8):

Purpose:

Add eight Gas Fitters (*i.e.*, four each in 2010 and 2011) to facilitate expansion of capital work performed by experienced Company forces.

Responsibilities:

- Fitters would perform main replacement work and New Business capital installations.
- Fitters would reduce Type 3 leak backlogs with additional main replacement and leak repair.

**ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO**

Attachment M

Highway Repairman (1):

Purpose:

Add one highway repairman to support the expanded activities of Gas Operations with the installation and replacement of gas mains and services by providing the roadway and highway paving repairs.

Responsibilities:

- Delivery and pickup of spoil, stone and sand to jobsites.
- Provide blacktop restoration.
- Provide topsoil and seeding where required.
- Transportation and delivery of large equipment and backhoes.
- Maintain and oversee Spring Valley Distribution Center spoil pile, stone and sand bins.
- Blacktop restoration in Northern Division for State and County highways.

**ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO**

Attachment N

Tool Room Mechanic (1):

Purpose:

The gas tool room is an important and invaluable part of the Gas Operations Department. Purchasing of equipment and material in order to perform the core operation of delivering and maintaining gas service to our customers in a safe and reliable manner is a department priority. As O&R assumes a larger role in capital main replacement programs, tools and equipment must be maintained and inventoried so that the equipment will work properly, safely and efficiently. Information about all tools and equipment must be compiled and updated so that spare parts and repairs can be made in a timely manner.

Responsibilities:

- Maintain inventory of tools and materials.
- Compile and maintain electronic logs of large capital tools and equipment.
- Maintain tools and equipment in good working condition and perform required repairs when necessary.
- Deliver materials, tools and/or maps to field crews.

**ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
RICHARD S. DI LORETO**

Attachment O

Gas Construction Supervisor (2):

Purpose:

Add one Gas Operations Supervisor in the Eastern Division and one in the Northern Division to supplement supervision of the expanded workforce for capital projects.

Responsibilities:

- Plan, organize, schedule and direct personnel engaged in the installation of gas mains and services.
- Supervise, train and develop employees in conformity with Company policy, labor agreements, safety priorities and other matters to maintain effective productivity.
- Coordinate with gas engineering, the projects to be completed throughout the year.
- Manage and oversee the capital main and service replacement projects.

CHARLES D. HUTCHESON

1 Q. Please state your name and business address.

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

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

5 A. I am employed by Consolidated Edison Company of New
6 York, Inc. ("Con Edison") and hold the position of
7 Manager, Property Tax and Depreciation. My duties
8 include the overall supervision and responsibility for
9 the property tax and depreciation functions for the
10 regulated companies of Consolidated Edison, Inc., which
11 includes Orange and Rockland Utilities, Inc. ("the
12 Company").

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

15 A. I graduated from Hofstra University in 1978 with the
16 degree of Bachelor of Business Administration in
17 Accounting. I have been employed by Con Edison since
18 1979 and have held various positions of increasing
19 responsibility within the Finance area. My first
20 assignment with Con Edison was in the Depreciation
21 Section. I spent my first 15 years of employment in
22 that area rising to the position of Senior Accountant.
23 In 1993, I moved to the Rates and Budget Section. In
24 1996, I transferred to the Financial Restructuring Team,

CHARLES D. HUTCHESON

1 where my duties were to assist on the development of Con
2 Edison's rate plan in the New York Public Service
3 Commission's ("Commission") Competitive Opportunities
4 Proceeding. I moved to the Tax Department in 1997 to
5 work as a Senior Tax Accountant in the Federal Tax
6 Section. In September 1999, I was promoted to Manager,
7 Property Taxes with responsibility for the property tax
8 compliance function. In December 2001, I once again
9 began working on depreciation matters when the Tax
10 Department assumed responsibility for the book
11 depreciation function. My depreciation responsibilities
12 include analyzing and interpreting the results of the
13 Company's statistical plant mortality and net salvage
14 studies.

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

16 A. Yes. I am a member of the Society of Depreciation
17 Professionals. The group was formed to recognize the
18 field of depreciation and those individuals contributing
19 to the field. It also promotes the professional
20 development of those practicing in the field of
21 depreciation and serves as a forum to collect and
22 exchange information and ideas related to depreciation.
23 Membership is not restricted to the utility industry as
24 the Society is represented by those in the fields of

CHARLES D. HUTCHESON

1 government, education, and industry.

2 Q. Have you previously testified before any regulatory
3 commission?

4 A. I have submitted testimony and testified on the subject
5 of depreciation and/or property taxes for the Company
6 and Con Edison before this Commission, as well as before
7 the New Jersey Board of Public Utilities on behalf of
8 Rockland Electric Company (the Company's New Jersey
9 utility subsidiary) and the Pennsylvania Utility
10 Commission on behalf of Pike County Light & Power
11 Company (the Company's Pennsylvania utility subsidiary),
12 in numerous cases.

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

15 A. I will present recommendations with respect to the
16 annual book depreciation rates for the Company's Gas
17 Plant. In addition, I will discuss property taxes,
18 including the Company's mitigation efforts to pay no
19 more than its fair share of property taxes.

20 DEPRECIATION

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

23 A. The estimated average service life is used to provide
24 for the recovery of the original cost of plant over its

CHARLES D. HUTCHESON

1 useful life. The depreciation expense accrual varies
2 inversely with its underlying average service life. The
3 shorter the service life, the higher the annual
4 depreciation rate, and therefore the higher the annual
5 depreciation expense.

6 Q. What part does salvage play in the determination of
7 depreciation rates?

8 A. In addition to providing for recovery of the original
9 cost of plant over its estimated average service life,
10 the Company's annual depreciation rates include an
11 estimated net salvage factor. The purpose of this
12 estimated net salvage factor is to reflect, over the
13 life of the plant, anticipated salvage less the expected
14 cost of removal upon retirement, in whole or on a
15 piecemeal basis, of the assets included in each primary
16 plant account.

17 Q. Have you reviewed the adequacy of the accumulated
18 provision for depreciation per books and the factors
19 that determine annual depreciation expense for Gas
20 Plant?

21 A. Yes, I have. The Company prepares annual studies that
22 test the accumulated provision for depreciation per
23 books. In addition, the Company prepares plant
24 mortality and net salvage studies to determine

CHARLES D. HUTCHESON

1 appropriate average service lives, net salvage factors,
2 and life tables for each depreciable asset account or
3 sub-account. The most recent studies were based on data
4 through year-end 2007.

5 Q. Based on these studies, are you recommending any changes
6 to depreciation rates and life tables related to the
7 Company's Gas Plant?

8 A. After a thorough review of the aforementioned annual
9 studies of depreciation and other factors that may
10 influence capital recovery, I have concluded that
11 various changes to the Company's depreciation parameters
12 are required which result in a modest increase in annual
13 depreciation expense for the Company.

14 Q. Have you prepared an exhibit for this proceeding that
15 summarizes your proposals?

16 A. Yes. I have prepared an exhibit titled "ORANGE AND
17 ROCKLAND UTILITIES, INC., PROPOSED DEPRECIATION RATE
18 CHANGES FOR GAS PLANT AT DECEMBER 31, 2007" (Exhibit G-
19 12, Schedule 1). This exhibit compares the annual
20 provision for depreciation on a "book basis" and on a
21 "proposed basis". This exhibit also includes a
22 comparison of the Accumulated Provision for Depreciation
23 per Books at December 31, 2007 to a computed reserve for
24 depreciation based on the depreciation parameters in

CHARLES D. HUTCHESON

1 effect today, as well as those that I am proposing in
2 this case.

3 Q. What is the basis for the changes you have proposed in
4 this proceeding?

5 A. The proposed changes are based primarily on my review
6 and analysis of the historical data comprising the
7 Company's mortality and net salvage studies. These
8 annual studies compute average service lives, h-curves,
9 and net salvage percentages employing actuarial methods
10 based on past experience. The data is organized into
11 various groupings, referred to as rolling or shrinking
12 bands, which aid in the analysis of the extensive
13 historical information available. In those instances
14 where certain accounts do not have sufficient retirement
15 results to produce statistically reliable mortality or
16 net salvage data, I relied on existing depreciation
17 parameters. However, for Gas General Plant, my
18 proposals reflect changes to match the depreciation
19 parameters that were approved in the Company's recently
20 concluded electric base rate case, Case No. 07-E-0949.
21 Therefore, the rates I am proposing in this case are
22 identical to the Electric General Plant and the Common
23 Utility Plant rates approved in the electric case.

24 Q. Why are you proposing those rates in this case?

CHARLES D. HUTCHESON

1 A. For several reasons. First, the Gas General Plant rates
2 are based on the same statistical studies as both the
3 Electric General Plant and the Common Utility Plant.
4 Second, these rates became effective only four months
5 ago, in July 2008. Third, I have reviewed the studies
6 they were based on and compared the results of those
7 studies to the studies I have done for this case and
8 consider the differences insignificant. Lastly, the
9 Common Utility Plant rates approved in the electric
10 proceeding include an excess reserve variation and a
11 portion of that variation is applicable to this rate
12 proceeding. I will fully address this variation later
13 in my testimony.

14 Q. Please describe the changes you propose affecting the
15 life tables of Gas Plant.

16 A. Life tables or "h-curves" are survivor curves
17 representing typical patterns of retirement dispersion.
18 An h-curve, along with an average service life and a net
19 salvage factor, is used to compute a theoretical reserve
20 for depreciation. Changes to h-curves do not impact
21 annual depreciation expense but do affect computed
22 reserves, which are used to help determine whether the
23 Company's depreciation reserve is adequate. As set
24 forth in column 11 (as compared with column 5) of

CHARLES D. HUTCHESON

1 Exhibit G-12, Schedule 1, I propose changes to several
2 h-curves to more adequately reflect observed retirement
3 dispersion patterns. My proposals include changes to
4 both increase and decrease h-values.

5 Q. Please generally describe the changes you propose
6 affecting the average service lives of Gas Plant.

7 A. I propose to change the service lives of many of the
8 Company's primary plant accounts or sub-accounts, the
9 majority of those changes toward shorter service lives.
10 These proposed changes are set forth in column 12 (as
11 compared with column 6) of Exhibit G-12, Schedule 1. In
12 terms of dollar impact, the only significant change I
13 have proposed is to lower the service life of the Mains
14 account (i.e., Account 376000 in Distribution Plant and
15 Account 367002 in Transmission Plant) from 75 years to
16 70 years based on my analysis of the statistical studies
17 set forth in Exhibit G-12, Schedule 2, which I will
18 introduce later in my testimony. Those changes result
19 in an increase in annual depreciation expense of
20 approximately \$245,000.

21 Q. Do you have an exhibit containing the data you relied on
22 to select the life tables and average service lives you
23 are proposing?

24 A. Yes. I have an exhibit entitled "ORANGE AND ROCKLAND

CHARLES D. HUTCHESON

1 UTILITIES, INC., GAS PLANT, SUMMARY OF AVERAGE SERVICE
2 LIVES, EQUIVALENT "h" CURVES AND OTHER STATISTICAL DATA
3 INDICATED BY PLANT MORTALITY STUDIES BASED ON EXPERIENCE
4 THROUGH DECEMBER 31, 2007" (Exhibit G-12, Schedule 2).

5 This exhibit includes computer generated average service
6 lives, equivalent h-curves, and other statistical data
7 indicated by the rolling and shrinking band analysis of
8 the Company's mortality experience with respect to Gas
9 Plant from 1952, or the earliest available date, through
10 2007.

11 Q. Was this exhibit prepared under your direction and
12 supervision?

13 A. Yes, it was.

14 Q. Please generally describe the changes that you propose
15 concerning the net salvage factors of Gas Plant.

16 A. I propose to change certain net salvage factors toward
17 higher and lower net salvage. In terms of both dollar
18 impact, as well as the absolute change in the net
19 salvage factor, the only significant change I have
20 proposed is to increase the net salvage factor for
21 Accounts 382000, 382100, 382400, and 384000. These
22 accounts all hold the investment related to the
23 installation costs of Meters or House Regulators. I
24 propose to change those net salvage factors from 0

CHARLES D. HUTCHESON

percent to 30 percent negative for each account based on my analysis of the statistical studies set forth in Exhibit G-12, Schedule 3, which I will introduce later in my testimony. Those changes result in an increase in annual depreciation expense of approximately \$186,000.

Q. Do you have an exhibit containing the data you relied on to determine your net salvage proposals?

A. Yes, I do. I have included an exhibit titled "ORANGE AND ROCKLAND UTILITIES, INC., GAS PLANT, SUMMARY OF HISTORICAL NET SALVAGE" (Exhibit G-12, Schedule 3).

This exhibit contains the historical net salvage for each depreciable Gas Plant account in dollar amount and as a percent of the book cost of plant retired. The book cost of plant retired, cost of removal and salvage are shown for the most recent 25 years for the actual retirements in the indicated calendar years. The exhibit also provides totals for the full experience band ending in year 2007, rolling bands five years in width, and a computation of the net salvage as a percent of the book cost retired for the full experience band, each rolling band, and each shrinking band.

Q. Was the exhibit prepared under your direction and supervision?

A. Yes, it was.

CHARLES D. HUTCHESON

1 Q. What effect will your proposed changes have on annual
2 depreciation expense?

3 A. As summarized on Exhibit G-12 (Schedule 1), the amount
4 of the annual provision for depreciation expense for the
5 Company's total Gas Plant, excluding the existing
6 amortization of an excess reserve being returned to
7 customers is approximately \$9.75 million under the
8 existing rates and approximately \$10.20 million under
9 the proposed rates. However, I note that those amounts
10 do not reflect total depreciation in the rate year as
11 they represent a computation at a single point in time,
12 i.e., December 31, 2007, and do not reflect changes in
13 forecasted plant balances. In addition, my exhibit does
14 not include Common Utility Plant, which has a portion of
15 its depreciation expense allocated to gas plant. The
16 Company's depreciation expense forecast, which is based
17 on my existing and proposed rates, is included in the
18 Accounting Panel's Exhibit G-4, Schedule 4.

19 Q. Since you have proposed changes affecting the
20 Accumulated Provision for Depreciation, please explain
21 the purpose of the depreciation reserve.

22 A. The Accumulated Provision for Depreciation, also
23 referred to as the Reserve per Books is, in simple
24 terms, an account balance that reflects the portion of

CHARLES D. HUTCHESON

1 the cost of the plant in service which has been
2 recovered, according to the Company's accounting
3 records. The original book cost of plant less the
4 Reserve per Books comprises net plant. Net plant does
5 not represent the plant's fair market value. The
6 Reserve per Books may be compared to the Computed
7 Reserve to test its adequacy. The Computed Reserve is
8 calculated on a book basis using depreciation parameters
9 currently approved by the Commission and may be
10 calculated on a proposed basis using parameters per my
11 analysis of the aforementioned depreciation studies.

12 Q. Please review your findings on the difference between
13 the Accumulated Provision for Depreciation per Books and
14 the Computed Reserve for depreciation.

15 A. The amounts I will address are summarized on Exhibit G-
16 12, Schedule 1 and exclude the unallocated reserve. The
17 exhibit shows that for total Gas Plant at December 31,
18 2007, the Accumulated Provision for Depreciation per
19 Books amounted to approximately \$120.4 million (see,
20 column 4). The Computed Reserve, summarized under the
21 heading "BOOK BASIS" was calculated on the basis of the
22 average service lives, net salvage percentages, and life
23 tables currently in use by the Company, and in total
24 amounted to approximately \$124.7 million (see, column

CHARLES D. HUTCHESON

1 9). The Computed Reserve shown under the heading
2 "PROPOSED BASIS" was calculated on the basis of the
3 average service lives, net salvage percentages and life
4 tables proposed by me and in total amounted to
5 approximately \$126.4 million (see, column 15).

6 Q. What have you concluded from the comparisons between the
7 book and computed reserves for depreciation you just
8 described and that are summarized in your exhibit?

9 A. The exhibit indicates that for total Gas Plant the
10 Accumulated Provision for Depreciation per Books,
11 excluding the unallocated reserve, is approximately \$4.3
12 million or 3.5% less than the Computed Reserve based
13 upon the book basis and approximately \$6.0 million or
14 4.7% less than the Computed Reserve based upon the
15 proposed basis. The variation between the Accumulated
16 Provision for Depreciation per Books and the Computed
17 Reserve based on both a book basis and a proposed basis
18 falls well within a 10% variation that could be
19 considered reasonable as a test of adequacy of the
20 Company's accumulated provision for depreciation per
21 books.

22 Q. Is there currently a reserve variation for the Company's
23 Gas Plant?

24 A. Yes. In Case No. 99-G-1695, a case which was settled by

CHARLES D. HUTCHESON

1 the parties and approved by the Commission, the
2 existence of an excess reserve in the amount of
3 \$10,253,952 was identified and the Company was directed
4 to amortize that excess back to customers. As of
5 December 31, 2007, an unamortized balance of \$3,933,786
6 remains in the depreciation reserve.

7 Q. What are you proposing to do with the reserve variation?

8 A. I am proposing that \$1,820,932 of that balance be used
9 to offset the estimated unrecovered plant costs of the
10 Company's Liquefied Petroleum (Propane) gas facilities,
11 some of which have already been retired and the
12 remainder of which are scheduled to be retired or
13 transferred to the Company's distribution plant by June
14 2009. After that retirement and transfer, I have
15 estimated that the excess reserve balance will amount to
16 \$1,292,353, and I propose to continue the amortization
17 at its current level of \$547,000 annually until it is
18 fully amortized.

19 Q. Why have you made such a proposal?

20 A. When the retirement of the remaining facilities takes
21 place, the Company will have no way to recover the
22 remaining unrecovered investment in those facilities
23 through depreciation since depreciation will cease with
24 the final retirement.

CHARLES D. HUTCHESON

1 Q. Please provide some background information concerning
2 the use of these gas facilities.

3 A. The Company has historically maintained three propane-
4 air peak shaving facilities to supplement gas supply
5 volumes during the coldest weather. Liquefied Natural
6 Gas storage and peak shaving has never been available
7 within our service territory. In 2002/2003, the Suffern
8 and Orangeburg plants were retired since sufficient gas
9 supplies were available because of the joint supply
10 portfolio after the merger with Con Edison.

11 Q. Why has the Middletown plant remained in service?

12 A. Our gas engineers have informed me that, at that time,
13 the production capacity of the Middletown plant remained
14 as a required supply. However, sufficient supply will
15 become available due to the opening of the new
16 Millennium Pipeline. The Company's joint portfolio with
17 Con Edison will be supplemented with enough supply from
18 the pipeline so that the Middletown plant may be retired
19 in mid-2009. Therefore, the Company plans to retire the
20 production facilities and transfer the remaining land
21 and structures to distribution plant.

22 Q. Do you have an exhibit containing the amounts relating
23 to the facilities that you are requesting to be
24 recovered?

CHARLES D. HUTCHESON

1 A. Yes, I have an exhibit titled "ORANGE AND ROCKLAND
2 UTILITIES, INC., GAS PLANT, DETERMINATION OF THE
3 UNRECOVERED COST OF LIQUEFIED PETROLEUM GAS FACILITIES
4 AS OF JUNE 30, 2009" (Exhibit G-12, Schedule 5). This
5 exhibit computes the estimated unrecovered cost of the
6 facilities after final retirement and associated
7 transfers.

8 Q. Please now discuss an excess reserve relating to the
9 Company's Common Utility Plant.

10 A. I identified an excess reserve in Common Utility Plant
11 in the Company's last electric case that amounted to
12 \$11,403,745. The amount of that excess applicable to
13 Gas amounts to \$3,335,595 and has been held in an
14 unallocated depreciation reserve account since July 1,
15 2008, the beginning of the first rate year in the
16 Commission approved electric rate plan.

17 Q. What are you proposing for this excess reserve
18 variation?

19 A. I propose for it to remain in the unallocated
20 depreciation reserve to be used to mitigate the recovery
21 of costs related to two extensive and expensive
22 technology systems the Company is planning to place into
23 service.

24 Q. What systems are you referring to?

CHARLES D. HUTCHESON

1 A. The Human Resources Payroll System ("HRPS") and the
2 General Ledger System "(GLS)".

3 Q. What are the costs of these systems?

4 A. The estimated costs to be recorded on O&R's books are
5 \$7.145 million for the GLS and \$3.0 million for the
6 HRPS. These costs are for the total company, and
7 encompass both hardware and software costs.
8 Approximately 25% of the software costs and 30% of the
9 hardware costs will be allocated to gas operations. The
10 Company estimates that the GLS will not be placed in
11 service until August 2012 while the HRPS will be placed
12 into service in January 2009.

13 Q. How would these systems be recovered?

14 A. For the associated software costs, the Company's
15 software policy states that the amortization period for
16 software costs is generally five years. That relatively
17 short amortization period takes into account that the
18 investments in these types of intangible assets normally
19 risk becoming technologically obsolete in a relatively
20 short period. However, that will not be the case for
21 the HR Payroll and General Ledger Systems which can be
22 expected to have a longer life and for which 15 years is
23 a more appropriate period over which to amortize these
24 costs. The hardware costs will be recovered over the

CHARLES D. HUTCHESON

1 average service life of the primary plant account
2 already in place to record such costs. In order to help
3 mitigate the revenue requirement impacts, I would use
4 the \$3.3 million balance in the unallocated reserve to
5 reduce the amortization expense over the first 5 years
6 they are in service by crediting expense ratably until
7 such time as the unallocated reserve is fully amortized.

8 Q. Please describe the treatment of the cost of removal for
9 the gas Mains and Services accounts you mentioned
10 earlier.

11 A. In Case 92-G-0050, the Commission approved a cap on the
12 net salvage charged to the depreciation reserve at 40%
13 negative for the Mains account and 80% negative for the
14 Services account. Any charges to the reserve in excess
15 of the cap limits are charged to maintenance expense and
16 that accounting treatment has continued since that time.
17 The amount charged to maintenance is determined by
18 establishing an allowance which needs to be reset in
19 each rate proceeding.

20 Q. Do you have an exhibit that computes this allowance?

21 A. Yes. I have an exhibit entitled "ORANGE AND ROCKLAND
22 UTILITIES, INC., NEGATIVE NET SALVAGE CAP ADJUSTMENT FOR
23 GAS MAINS AND SERVICES, 2003 - 2007" (Exhibit G-12,
24 Schedule 4).

CHARLES D. HUTCHESON

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

3 A. Yes, it was.

4 Q. What information is contained in this exhibit?

5 A. This exhibit computes the excess net salvage for each of
6 the accounts based on five years of actual net salvage
7 experience. That amount is then brought forward to the
8 rate year by way of an inflation factor provided to me
9 by the Company's Accounting Panel, and finally, the new
10 amount is compared to the currently allowed amount in
11 rates to arrive at a net adjustment for this case
12 amounting to a \$30,000 decrease for the Mains account
13 and a \$180,000 increase for the Services account.

14 PROPERTY TAXES

15 Q. How are the Company's property taxes calculated?

16 A. The property taxes Orange and Rockland pays are based on
17 the "value" of its property and include taxes on land
18 and the structures erected or affixed to the land. In
19 New York State, utilities also pay property taxes on
20 utility equipment located on land owned by the utility
21 and on equipment located on or under the public streets
22 and highways. The Company pays property taxes to
23 various municipalities and school districts throughout
24 our service territory to support their operations.

CHARLES D. HUTCHESON

In New York State, the Courts have held that public utility property should be valued under a method known as the "Cost Approach." The New York State Office of Real Property Services ("ORPS"), the central assessing body in the State for property located on the public streets or highways, determines value by using a Reproduction Cost New Less Depreciation ("RCNLD") methodology for utility property. However, very few municipalities value the Company's real estate property (i.e., property not situated on publicly owned land) under RCNLD. Instead of an RCNLD valuation, the municipality at best sets assessments at original construction cost, where it remains until retirement. At worst, assessments may be set without any factual basis. Therefore, our objective is to have all of our property calculated under RCNLD as it more closely matches the property's true value. RCNLD calculates what it would cost to reproduce property at current construction costs, subtracts an allowance for depreciation and obsolescence, if any, and adds in the value of land to arrive at a "value" for the entire property. RCNLD is used only to value certain of the Company's structures and all of our equipment. The

CHARLES D. HUTCHESON

1 value of land and office buildings is determined by
2 comparable sales data.

3 Q. Does the Company review its property assessments?

4 A. Yes. Annually, we review our property assessments to
5 determine if they fall within a range of reasonableness
6 when calculated under RCNLD. If the actual assessments
7 substantially vary from our RCNLD calculations, we file
8 complaints to protect our rights and those of our
9 customers. We settle these complaints when we believe
10 that a settlement is a more cost effective way of
11 reducing our tax burden than prolonged, costly, and
12 risky litigation. We litigate only when our efforts to
13 reach what we believe to be an equitable compromise
14 fail.

15 Q. What level of property taxes does the Company experience
16 for its gas plant?

17 A. In 2007, we paid \$26.2 million in total property taxes,
18 of which about a third, or \$8.33 million was charged to
19 gas. For 2008, I have forecasted property taxes
20 associated with gas operations to be \$9.13 million. My
21 forecast for the rate year ending October 2010 is \$9.94
22 million.

23 Q. Please describe the method used to forecast property
24 taxes.

CHARLES D. HUTCHESON

1 A. I have forecasted the property taxes associated with gas
2 operations by taking the latest known property taxes and
3 increasing those amounts through use of a five-year
4 average of actual tax bill changes experienced by the
5 Company. The resulting annual percentage increase per
6 that analysis was 2.39%, however, I have increased that
7 percentage to 6.00% because I have noticed that actual
8 payments in 2008 have increased rather significantly and
9 the deteriorating economic climate presents a greater
10 risk to the property taxes the Company may be facing in
11 the future. Since the Company has property located in
12 numerous municipalities with different tax rates,
13 equalization rates, and assessment methodologies,
14 experience has shown that the best way to estimate the
15 Company's property taxes is to base them on past
16 experience levels and adjust that for significant items,
17 if known. The forecasted changes were apportioned over
18 the appropriate tax fiscal year to determine the
19 projected property tax expense in the rate year.

20 Q. Please discuss the Company's efforts to minimize its
21 property taxes.

22 A. Property tax amounts are a function of a tax rate
23 multiplied by equalized assessed values. Individual and
24 corporate taxpayers have little influence over a tax

CHARLES D. HUTCHESON

1 rate in a municipality. Accordingly, our focus is on
2 the fairness of assessments.

3 Q. Have you been successful?

4 A. The Company challenges its assessments when we determine
5 the Company is being unfairly assessed and it is cost
6 effective to do so. Therefore, we tend to challenge our
7 assessments on our larger properties, most of which tend
8 to serve our electric customers. In the recent past,
9 the Company has been successful in arriving at reduced
10 assessments in several communities, arriving at
11 settlement agreements in the Towns of Clarkstown,
12 Ramapo, Haverstraw, and Orangetown. The Company has not
13 had the need to challenge the assessments for any of the
14 properties in these communities since the agreements
15 became effective. A large share of the Company's gas
16 properties is located in these municipalities.

17 Q. Please describe pending actions on property taxes now in
18 progress.

19 A. The Company currently has actions pending in the Town of
20 Monroe and the City of Middletown where a small portion
21 of these claims relates to gas plant properties.

22 Q. Why do property taxes continue to rise despite your
23 efforts?

24

CHARLES D. HUTCHESON

1 A. Local property taxes are used to finance local
2 governments and public schools. The funds raised via
3 the property tax levy are the major revenue source for
4 these municipalities and, indeed, are sometimes the only
5 source of revenue. Municipalities have had to raise
6 local tax rates in order to meet their expenses.

7 Q. Have you taken the current economic climate into
8 consideration to forecast property taxes?

9 A. Yes, as I indicated earlier. However, I cannot predict
10 how municipalities will deal with the current
11 deteriorating economic climate. I presume those that
12 face problems will deal with them through a combination
13 of budget cuts and tax increases. That said, I expect
14 that the Company will face tax increases above and
15 beyond a "normal" level in the near term. In order to
16 reflect that, I increased the escalation percentage in
17 my forecast above the five year computed average I
18 described earlier to reflect both the deteriorating
19 economic climate as well as the recent increases in 2008
20 taxes being experienced by the Company.

21 Q. How do you determine which properties are over-valued?

22 A. We have an internally developed computer program to
23 evaluate our assessments. This system uses the RCNLD
24 methodology similar to the method used by the ORPS. We

CHARLES D. HUTCHESON

1 use this system to compare our actual assessments for
2 any given municipality to their theoretical values.
3 When we find we are over-assessed, we file
4 administrative complaints and pursue those complaints
5 through the courts, via tax certiorari cases if
6 necessary.

7 Q. How are property taxes treated in the Company's current
8 gas rates?

9 A. The Commission has recognized the volatility of property
10 taxes and the effects that large changes in the amounts
11 can have on the Company's financial position. Our
12 current gas rate plan allows the Company to defer 100%
13 of taxes applicable to tax rate changes and 86% of taxes
14 relating to assessment changes above or below the level
15 forecasted for the rate year. From an accounting
16 perspective, this is accomplished by comparing the level
17 of taxes in rates to the actual taxes incurred. The
18 variation is deferred and either collected from
19 customers or returned to them at the end of the current
20 rate agreement. The Company's Accounting Panel
21 addresses a proposal to reconcile property taxes as well
22 as the current balance in the deferral.

23 Q. How are property tax refunds treated under the Company's
24 present rate plan?

CHARLES D. HUTCHESON

1 A. Consistent with long-standing policy, the Commission has
2 allowed utilities to retain a percentage of tax refunds
3 to encourage them to challenge questionably imposed
4 taxes. Our current gas rate plan allows the Company to
5 retain 14 percent of property tax refunds (including
6 credits or assessment reductions against future taxes in
7 lieu of cash refunds), resulting from the Company's
8 efforts, with 86 percent of the refund to be deferred
9 for the benefit of customers. Outside legal and other
10 incremental costs incurred by the Company in pursuing
11 such property tax refunds are first deducted from any
12 such refunds and/or credits before any allocation is
13 made to the Company and its customers.

14 Q. Do you propose to continue that treatment?

15 A. Yes, I do.

16 Q. Does that conclude your testimony?

17 A. Yes, it does.

18

19

20

21

22

23

24

Orange and Rockland Utilities, Inc.
Direct Testimony of
Donald E. Kennedy JR.

1 Q. Please state your name and business address.

2 A. My name is Donald E. Kennedy, Jr. My business address is 390 West Route 59
3 Spring Valley, NY 10977

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" or
6 the "Company") as Director of New Construction Services. In this position, I
7 manage the installation of electric and gas services for Orange and Rockland and
8 its subsidiaries Pike County Light & Power Company and Rockland Electric
9 Company.

10 Q. Please summarize your educational background and business experience.

11 A. In 1998, I graduated from the State University of New York, Rockland
12 Community College with an Associate Degree in Math and Science. In 2002, I
13 graduated from the State University of New York, Empire State College, with a
14 Bachelor of Science in Business Administration. I am currently attending Walden
15 University working towards a Masters in Business Administration. In 1981, I
16 joined the Company as a Meter Reader. I have since held the positions of
17 Supervisor- Meter Reading , Senior Supervisor - Customer Accounting, Manager
18 - Customer Accounting, Manager - Customer Service and Director - Customer
19 Service prior to my present position.

20 Q. Have you ever testified before the New York State Public Service Commission
21 ("NYSPSC")?

22 A. No, I have not.

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

2 A. I will testify to the Company's proposed gas economic development expansion
3 plans for Orange County, New York, as well as its proposed natural gas
4 conversion plans for residential and commercial customers.

5 **Continuation of Gas Economic Development Enhancement Pilot Program**

6 Q. Is the Company proposing to continue the Gas Economic Development
7 Enhancement Pilot Program ("Pilot Program") adopted by the Commission in
8 Orange and Rockland's last gas rate case (*i.e.*, Case 05-G-1494)?

9 A. Yes

10 Q. Why does the Company wish to continue the Pilot Program?

11 A. Demographic and economic statistics indicate that Orange County has
12 experienced fast-paced population and economic growth over the past eight
13 years. In fact, Orange County experienced the fastest population growth rate of
14 any County in New York State, increasing from 341,367 at the time of the 2000
15 census to 370,352 in the 2005 census, a 9% growth rate over five years. The
16 Orange County population growth rate from 2005 -2007 has slowed to 4% per
17 year. Also, a major indicator of economic health is unemployment rates which
18 increased slightly from 4.4% in 2004 to 5.1% in 2008. Employment levels rose
19 from 164,500 in 2004 to 168,357 in 2008. Per capita personal income increased
20 by 31% from 2000-2007 and the average home selling price in the County
21 increased from about \$285,000 in 2005 to \$304,685 in 2007. While economic
22 growth in Orange County has slipped slightly, as a result of the Nation's

1 economic slow down, the Company is confident the growth rate will continue to
2 increase as the economy begins to rebound.

3 In addition, natural gas is the fuel of choice for builders and developers, including
4 both residential and commercial and industrial sites, due not only to competitive
5 pricing but also to environmental considerations, maintenance issues and general
6 convenience of the product and delivery. However, developers will install
7 propane or oil systems when gas service is not available, resulting in lost business
8 opportunities for the Company. Eventually, the Company would hope to take full
9 advantage of its franchise rights in Orange County. The Company would
10 approach any expansion, however, in a systematic, project-by-project manner,
11 taking into consideration such factors as municipal planning and zoning priorities
12 (targeting areas of planned growth), our own gas system reinforcement needs,
13 capital budget and cash constraints, and the potential for earning required returns
14 over reasonable periods.

15 Q. During the Company's current gas rate plan, how many projects have been
16 implemented pursuant to the Pilot Program and how were these projects selected?

17 A. To date, the Company has implemented the following four projects: Larkin Drive,
18 Monroe, NY; Dolsontown Road, Waywayanda, NY; Goshen Turnpike, Wallkill,
19 NY; and Route 17M, Monroe, NY.

20 The Company has cultivated and maintains business relationships with realtors,
21 planning boards, municipalities, and zoning commissions throughout Orange
22 County. Working with these agencies, the Company identifies, before service
23 requests are actually made, areas where significant development appears

1 imminent, and where development has either been approved or where building
2 applications have been made. In addition, certain municipalities have identified
3 “priority growth areas” within their jurisdictions. Priority projects for the Pilot
4 Program are identified using town planning data such as those mentioned, as well
5 as the Company’s gas system reinforcement needs and redundancy planning
6 criteria.

7 Once a potential project is identified, the Company completes a financial analysis.
8 Estimated construction costs, revenue, operation and maintenance expenses,
9 depreciation, and taxes, are calculated, and a project-specific rate base is
10 developed. The adequacy of project-specific net income, cash flows and returns
11 are evaluated. A project may be deemed to be financially feasible even if it is not
12 projected to earn significant returns for several years. For example, working with
13 municipal agencies to identify future growth potential in a specific area may result
14 in the recommendation to go forward with a gas main extension that will initially
15 result in minimal revenue but could result in significant future revenue.

16 If the project is determined to be feasible from both an operating and financial
17 prospective, the Company will move forward with the project. The Company will
18 report its results at year end to the New York State Department of Public Service
19 (“NYSDPS”), Director of Economic Development and Policy Coordination, on
20 projects accepted and rejected, along with the criteria used for such a
21 determination. In the interim, the Company earns a carrying charge on the
22 project-specific rate base at the then-allowed overall return for gas operations.

1 The carrying charge is recoverable in the modified gas clause adjustment until the
2 time when revised gas base rates are approved and implemented.

3 Q. Has the Pilot Program been successful?

4 A. Yes, the Pilot Program is viewed as an overall success by the customers, the
5 Company and Orange County officials. Of the four projects selected, each meets
6 the criteria defined in the pilot program for supporting economic expansion. No
7 project selected by the Company exceeded a construction cost of \$310,000. After
8 conducting a review of the completed projects and investigating potential
9 projects, the Company has concluded that it is highly unlikely that additional
10 projects remain in the Orange County service territory, which meets the current
11 Pilot Program criteria.

12 Q. What changes to the Pilot Program is the Company proposing?

13 A. While the Company wishes to continue the program, it requires additional
14 program funding to take on larger projects which will have a more significant
15 impact on economic development within Orange County. Therefore, the
16 Company is proposing that each completed project be funded up to an amount
17 equal to 80% of the revenue requirements necessary to support the Company's
18 allowed rate of return and associated carrying costs. The Company is proposing
19 the deferred regulatory asset remain capped at \$750,000 for the period of the rate
20 plan. The allowed rate of return will be based on the overall rate of return
21 approved in the Commission-approved rate plan resulting from this proceeding.
22 The Company agrees to abide by the other terms of the current Pilot Program.

23

1 **Natural Gas Conversion Plan**

2 Q. Is the Company proposing a plan to expand its ability to provide natural gas
3 service to its customers?

4 A. Yes. The Company intends to continue to expand its natural gas facilities so that it
5 can serve customers who currently do not have access to natural gas service.

6 Both residential and commercial customers, presently heating with oil and/or
7 propane, have expressed an increased interest in converting to natural gas. On
8 average from 2003-2007, the Company experienced conversions from oil and/or
9 propane to natural gas at a rate of 130 per year. For 2008 (through October), the
10 Company has received 300 conversion requests (234 residential and 66
11 commercial). As set forth in Exhibit __ (DEK-1), during 2008, rising prices have
12 impacted customers' choice of fuel, with oil reaching \$4.74, propane \$4.88 and
13 natural gas at \$2.42 to provide 140,000 BTUs of heat. While the prices of all
14 fuels have fallen recently, due primarily to the underlying global economic
15 slowdown, the Company considers this decline to be a short-term trend. Given
16 the prospects of increasing global demand, the long-term price of oil will continue
17 to rise. Customer feedback also indicates their preference of natural gas over oil
18 as a means for reducing the Nation's foreign dependence on oil and due to the fact
19 that gas is cleaner burning than oil, which is better for the environment.

20 Q. What plan is the Company proposing?

21 A. The Company is proposing a plan with two components. The first is designed to
22 better meet the needs of residential customers who wish to convert to gas heat.

1 The second employs alternative methods of evaluating commercial gas
2 conversion projects, which exceed the traditional tariff entitlements.

3 **Residential Customer Conversions**

4 Q. Please discuss the first component of the plan.

5 A. Upon receiving a residential customer request to convert to natural gas, a
6 Company representative will visit the customer's home, in addition to others in
7 the area to ascertain if neighbors are interested in converting to natural gas. What
8 the Company often finds is that customers living at the middle or end of the street
9 are subject to additional construction costs since they fall short of the traditional
10 tariff entitlement. Tariff entitlements allow customers 100 feet of gas main
11 (extension of main in street or public right of way) and 100 feet of service (from
12 the street to the customers home), free of charge. Any additional distance beyond
13 the 100 feet must be paid by the customer at a rate of approximately \$37.00 per
14 foot for main and \$18.00 per foot for service. After purchasing or upgrading a
15 furnace and removing or remediating oil storage facilities, customers often do not
16 have the funds available to invest in extending a gas main or paying for a service
17 extension, leaving customers frustrated and disappointed.

18 Q. How often does this occur?

19 A. The Company has investigated over 300 potential conversions which did not
20 occur as a result of the customer contribution requirement. These are projects
21 where customer entitlements exceeded 100 feet of main or 100 feet of service. Of
22 the 300 potential conversions investigated, the Company is certain that 60
23 customers would have converted, and estimates that an additional 75-100, would

1 have converted, had the customers not been required to contribute towards the
2 construction expense.

3 Q. What does the Company propose to help customers avoid this added expense?

4 A. The Company proposes to extend the tariff entitlements for residential conversion
5 customers from 100 feet of main and 100 feet of service to 200 feet of main and
6 200 feet of service for the duration of the rate plan approved by the Commission
7 in this proceeding, provided that the additional 100 feet does not place an undue
8 financial burden on the Company. The Company reserves the right to reject
9 projects requiring more than 100 feet of main and 100 feet of service, if the costs
10 involved are above and beyond those incurred in a typical gas conversion. For
11 example, if the cost of the project exceeds 200 feet of main at \$37.00 per foot and
12 200 feet of service at \$18.00 per foot, the customer is responsible for any and all
13 additional costs above 100 feet. The Company has determined, as set forth in
14 Exhibit __ (DEK-2) that the incremental average cost of both Company and
15 contractor resources to install an additional 100 feet of service and/or main is a
16 justifiable investment which will increase the number of customers heating with
17 natural gas and meet the needs of customers requesting natural gas service. While
18 the Company is proposing to extend entitlements to 200 feet of service and 200
19 feet of main, as set forth in Exhibit ____ (DEK-3), the Company expects the
20 average for all projects will equal approximately 150 feet, since not every gas
21 conversion will require the full entitlement. Many of the projects the Company
22 evaluated require more than 100 feet, but less than 200 feet of entitlements, as set
23 forth in Exhibit__ (DEK-2). As outlined in Exhibit__ (DEK-2), the Company will

1 earn its allowed rate of return in Rate Year One when installing 150 feet of main
2 and 150 feet of service. Projects requiring 200 feet of main and 200 feet of
3 service will earn the approved rate of return in Rate Year Three. In addition,
4 extending the entitlements will have a positive impact on the Company's
5 customer base by adding more customers to the gas system.

6 Q. Has the Company estimated how many customers this change might impact?

7 A. In Orange and Rockland Counties, the Company has 8,650 non-gas customers
8 living within 200 feet of a gas main. Customers living within this proximity to a
9 gas main would benefit from this change, specifically customers with older
10 heating systems ready for replacement.

11 **Commercial Conversions**

12 Q. Please discuss the second component of the plan?

13 A. The Company has several projects underway to rebuild, replace and enhance
14 reliability within its system. As a result, between 2008 and 2009 alone, over
15 56,000 feet of natural gas main will be installed. Additional and similar projects
16 are proposed over the next two to three years. As new natural gas main is
17 installed and old main is replaced, opportunities are created to convert oil and
18 propane heating customers along the construction route, to natural gas. During
19 2008, fifteen residential and seven commercial customers were converted to
20 natural gas resulting from three construction projects.

21 Q. How is the Company able to respond to customer requests for natural gas?

22 A. Currently the Company has one employee who handles natural gas conversion
23 requests throughout all of Orange County, which includes 26 towns and villages.

1 The increased demand for natural gas has made it difficult to meet customer
2 requests on a timely basis.

3 Q. What does the Company propose for evaluating commercial gas conversion
4 projects?

5 A. The Company is proposing the use of a financial analysis model to determine if
6 commercial oil to gas conversion project is cost effective. Commercial customers
7 are entitled to 100 feet of main only, based on the number of meters served. All
8 other construction costs must be paid by the customer. In the case of a
9 condominium or co-op, several hundred people may occupy a building served by
10 one master meter, but only 100 feet of entitlement is available.
11 Similar to residential projects, the cost may far exceed what the customer is
12 capable of paying, considering apartments and condominiums may be on
13 commercial rates if master metered. Therefore, the Company proposes to use the
14 financial analysis model set forth in Exhibit __ (DEK-4) to identify those
15 commercial projects that it makes financial sense for the Company to pursue.
16 Specifically, the Company proposes to complete projects which meet its earnings
17 targets within three years, based on the financial analysis performed. The
18 Company will provide Staff with an annual report of all commercial projects
19 which were considered in addition to all projects which met the defined criteria
20 and were actively pursued and completed by the Company.

21 Q. How does the Company plan to meet future demand for natural gas conversions?

22 A. The Company proposes to add one employee to the New Construction Services
23 Department to work with customers interested in converting to natural gas.

1 Customer phone inquiries reached an all time high, exceeding 350 inquiries
2 relating to the location of natural gas facilities and additional information about
3 gas. While the Company was not able to meet customer demands, we expect
4 customer demand for natural gas to remain high over the long term. To establish
5 an organized approach to meeting customer needs the Company intends to
6 identify streets, routes and neighborhoods, within its service area that are within
7 200 feet of a gas main and solicit customer interest for converting to natural gas.

8 Q. Does that complete your testimony?

9 A. Yes, it does.

10

BEFORE THE NEW YORK STATE PUBLIC SERVICE COMMISSION

In the matter of:

APPLICATION OF ORANGE AND)
ROCKLAND UTILITIES , INC.) CASE NO. 08-G-0000 _____
FOR AN INCREASE IN GAS RATES)

DIRECT TESTIMONY

OF

ROGER A. MORIN, PhD

NOVEMBER 26, 2008

TABLE OF CONTENTS

	<u>PAGE</u>
I. INTRODUCTION AND PURPOSE	1
II. REGULATORY FRAMEWORK AND RATE OF RETURN	6
III. COST OF EQUITY ESTIMATES	13
IV. RISK PREMIUM ANALYSES	15
A. CAPM ESTIMATES	15
B. HISTORICAL RISK PREMIUM	28
C. DCF ESTIMATES	28
V. SUMMARY OF COST OF EQUITY RECOMMENDATION	48

EXHIBITS

APPENDIX A	CAPM, Empirical CAPM
APPENDIX B	Flotation Cost Allowance
EXHIBIT RAM-1	Resume of Roger A. Morin
EXHIBIT RAM-2	Natural Gas Distribution Utilities/Beta Estimates and Combination Gas & Electric Beta Estimates
EXHIBIT RAM-3	S&P Utility Index Common Stocks Over Long Term Treasury Bonds – Annual Long-Term Risk Premium Analysis
EXHIBIT RAM-4	Natural Gas Utilities DCF Analysis: Analysts’ Growth Forecasts
EXHIBIT RAM-5	Natural Gas Utilities DCF Analysis: Value Line Growth Forecasts
EXHIBIT RAM-6	Combination Gas & Electric Utilities - DCF Analysis: Value Line Growth Projections
EXHIBIT RAM-7	Combination Gas & Electric Utilities – DCF Analysis: Analysts’ Growth Projections

I. INTRODUCTION AND PURPOSE

1 **Q. PLEASE STATE YOUR NAME, ADDRESS, AND OCCUPATION.**

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

8 **Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.**

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

12 **Q. PLEASE SUMMARIZE YOUR ACADEMIC AND BUSINESS CAREER.**

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

1 Utilities Reports, Inc.

2 I have authored or co-authored several books, monographs, and articles in academic
3 scientific journals on the subject of finance. They have appeared in a variety of journals,
4 including The Journal of Finance, The Journal of Business Administration, International
5 Management Review, and Public Utilities Fortnightly. I published a widely-used treatise on
6 regulatory finance, Utilities' Cost of Capital, Public Utilities Reports, Inc., Arlington, Va. 1984.
7 In late 1994, the same publisher released Regulatory Finance, a voluminous treatise on the
8 application of finance to regulated utilities. A revised and expanded edition of this book entitled
9 The New Regulatory Finance was published in August 2006. I have engaged in extensive
10 consulting activities on behalf of numerous corporations, legal firms, and regulatory bodies in
11 matters of financial management and corporate litigation. Exhibit No. ____ (RAM-1) describes
12 my professional credentials in more detail.

13 **Q. HAVE YOU PREVIOUSLY TESTIFIED ON COST OF CAPITAL BEFORE UTILITY**
14 **REGULATORY COMMISSIONS?**

15 A. Yes, I have been a cost of capital witness before nearly fifty (50) regulatory bodies in North
16 America, including the New York State Public Service Commission ("NYPSC" or
17 "Commission"), the Federal Energy Regulatory Commission, and the Federal Communications
18 Commission. I have also testified before the following state, provincial, and other local regulatory
19 commissions:

Alabama	Florida	Missouri	Ontario
Alaska	Georgia	Montana	Oregon
Alberta	Hawaii	Nevada	Pennsylvania
Arizona	Illinois	New Brunswick	Quebec
Arkansas	Indiana	New Hampshire	South Carolina
British Columbia	Iowa	New Jersey	South Dakota

California	Kentucky	New Mexico	Tennessee
City of New Orleans	Louisiana	New York	Texas
Colorado	Maine	Newfoundland	Utah
CRTC	Manitoba	North Carolina	Vermont
Delaware	Maryland	North Dakota	Virginia
District of Columbia	Michigan	Nova Scotia	Washington
FCC	Minnesota	Ohio	West Virginia
FERC	Mississippi	Oklahoma	

Details of my participation in regulatory proceedings are provided in Exhibit RAM-1.

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

2 A. The purpose of my testimony in this proceeding is to present an independent appraisal of the fair
3 and reasonable rate of return on the natural gas utility operations of Orange and Rockland
4 Utilities, Inc.'s ("O&R" or the "Company") in the State of New York with particular emphasis
5 on the fair return on O&R's common equity capital committed to that business. Based upon this
6 appraisal, I have formed my professional judgment as to a return on such capital that would: (1)
7 be fair to the customer, (2) allow the Company to attract capital on reasonable terms, (3)
8 maintain the Company's financial integrity, and (4) be comparable to returns offered on
9 comparable risk investments. I will testify in this proceeding as to that opinion.

10 This testimony and accompanying schedules were prepared by me or under my direct
11 supervision and control. The source documents for my testimony are Company records, public
12 documents, commercial data sources, and my personal knowledge and experience.

13 **Q. PLEASE BRIEFLY IDENTIFY THE EXHIBITS AND APPENDICES**
14 **ACCOMPANYING YOUR TESTIMONY.**

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

1 **Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATION.**

2 A. I have examined O&R's risks, and concluded that O&R's risk environment is comparable to the
3 industry average. It is my opinion that a just and reasonable rate of return on common equity
4 ("ROE") invested in O&R's natural gas delivery operations is 11.0%. My recommendation is
5 derived from studies that I performed using the Capital Asset Pricing Model ("CAPM"), Risk
6 Premium, and Discounted Cash Flow ("DCF") methodologies. I performed two CAPM
7 analyses, one using the plain vanilla CAPM and another using an empirical approximation of the
8 CAPM ("ECAPM"). I performed two risk premium analyses: (1) a historical risk premium
9 analysis on the utility industry, and (2) a study of the risk premiums allowed in the natural gas
10 utility industry. I also performed DCF analyses on two surrogates for the Company's natural gas
11 delivery business. They are: a group of investment-grade natural gas distribution utilities and a
12 group of investment-grade combination gas and electric utilities.

13 My recommended rate of return reflects the application of my professional judgment to
14 the results in light of the indicated returns from my Risk Premium, CAPM, and DCF analyses.
15 My recommended ROE also assumes the approval of the Company's rate year capital structure
16 consisting of 48% common equity capital.

17 **Q. PLEASE EXPLAIN HOW LOW AUTHORIZED RETURNS ON EQUITY CAN**
18 **INCREASE BOTH THE FUTURE COST OF EQUITY AND DEBT FINANCING.**

19 A. If a utility is authorized a ROE below the level required by equity investors, the utility (or its
20 parent) will find it difficult to access the equity market through common stock issuance at its
21 current market price. Investors will not provide equity capital at the current market price if the
22 earnable ROE is below the level they require given the risks of an equity investment in the

1 utility. The equity market corrects this by generating a stock price in equilibrium that reflects the
2 valuation of the potential earnings stream from an equity investment at the risk-adjusted return
3 equity investors require. In the case of a utility that has been authorized a return below the level
4 investors believe is appropriate for the risk they bear, the result is a decrease in the utility's
5 market price per share of common stock. This reduces the financial viability of equity financing
6 in two ways. First, because the utility's share price per common stock decreases, the net
7 proceeds from issuing common stock are reduced. Second, since the utility's market to book
8 ("M/B") ratio decreases with the decrease in the share price of common stock, the potential risks
9 from dilution of equity investments reduces investors' inclination to purchase new issues of
10 common stock. The ultimate effect is the utility will have to rely more on debt financing to meet
11 its capital needs.

12 As the company relies more on debt financing, its capital structure becomes more
13 leveraged. Because debt payments are a fixed financial obligation to the utility, and income
14 available to common equity is subordinate to fixed charges, this decreases the operating income
15 available for dividend and earnings growth. Consequently, equity investors face greater
16 uncertainty about future dividends and earnings from the firm. As a result, the firm's equity
17 becomes a riskier investment. The risk of default on the company's bonds also increases, making
18 the utility's debt a riskier investment. This increases the cost to the utility from both debt and
19 equity financing and increases the possibility the company will not have access to the capital
20 markets for its outside financing needs. Ultimately, to ensure that O&R has access to capital
21 markets for its capital needs, a fair and reasonable authorized ROE of 11.0% is required.

1 **Q. DR. MORIN, PLEASE DESCRIBE HOW YOUR TESTIMONY IS ORGANIZED.**

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

3 I. Regulatory Framework and Rate of Return;

4 II. Cost of Equity Estimates; and

5 III. Summary and Cost of Equity Recommendation.

6 The first section discusses the rudiments of rate of return regulation and the basic notions
7 underlying rate of return. The second section contains the application of CAPM, Risk Premium,
8 and DCF tests. The third section summarizes the results from the various approaches used in
9 determining a fair return.

II. REGULATORY FRAMEWORK AND RATE OF RETURN

10 **Q. WHAT ECONOMIC AND FINANCIAL CONCEPTS HAVE GUIDED YOUR**
11 **ASSESSMENT OF O&R'S COST OF COMMON EQUITY?**

12 A. Two fundamental economic principles underlie the appraisal of the Company's cost of equity,
13 one relating to the supply side of capital markets, the other to the demand side. According to the
14 first principle, a rational investor is maximizing the performance of his portfolio only if he
15 expects the returns earned on investments of comparable risk to be the same. If not, the rational
16 investor will switch out of those investments yielding lower returns at a given risk level in favor
17 of those investment activities offering higher returns for the same degree of risk. This principle
18 implies that a company will be unable to attract the capital funds it needs to meet its service
19 demands and to maintain financial integrity unless it can offer returns to capital suppliers that are
20 comparable to those achieved on competing investments of similar risk. On the demand side, the
21 second principle asserts that a company will continue to invest in real physical assets if the return

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

4 **Q. HOW DOES O&R'S COST OF CAPITAL RELATE TO THAT OF ITS PARENT**
5 **COMPANY, CONSOLIDATED EDISON, INC. ("CEI")?**

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

13 For example, if an individual investor borrows money at the bank at an after-tax cost of
14 8% and invests the funds in a speculative oil extraction venture, the required return on the
15 investment is not the 8% cost but, rather, the return foregone in speculative projects of similar
16 risk, say 20%. Similarly, the required return on O&R is the return foregone in comparable risk
17 energy delivery operations, and is unrelated to the parent's cost of capital. The cost of capital is
18 governed by the risk to which the capital is exposed and not by the source of funds. The identity
19 of the shareholders has no bearing on the cost of equity, be it either individual investors or a
20 parent holding company.

21 Just as individual investors require different returns from different assets in managing
22 their personal affairs, corporations behave in the same manner. A parent company normally

1 invests money in many operating companies of varying sizes and varying risks. These operating
2 subsidiaries pay different rates for the use of investor capital, such as for long-term debt capital,
3 because investors recognize the differences in capital structure, risk, and prospects between
4 subsidiaries. Thus, the cost of investing funds in an operating utility entity such as O&R is the
5 return foregone on investments of similar risk and is unrelated to the investor's identity.

6 **Q. UNDER TRADITIONAL COST OF SERVICE REGULATION, PLEASE EXPLAIN**
7 **HOW A REGULATED COMPANY'S RATES SHOULD BE SET.**

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

15 Funds can be obtained in two general forms, debt capital and equity capital. The cost of
16 debt funds can be easily ascertained from an examination of the contractual interest payments.
17 The cost of common equity funds, that is, investors' required rate of return, is more difficult to
18 estimate. It is the purpose of the next section of my testimony to estimate O&R's cost of
19 common equity capital.

20 **Q. DR. MORIN, WHAT MUST BE CONSIDERED IN ESTIMATING A FAIR ROE?**

21 A. The legal requirement is that the allowable ROE should be commensurate with returns on
22 investments in other firms having corresponding risks. The allowed return should be sufficient

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

11 **Q. WHAT FUNDAMENTAL PRINCIPLES UNDERLIE THE DETERMINATION OF A**
12 **FAIR AND REASONABLE ROE?**

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

- 18 1. Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia,
19 262 U.S. 679 (1923).
- 20 2. Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944).

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

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

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

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

20 The United States Supreme Court reiterated the criteria set forth in Hope in Federal
21 Power Commission v. Memphis Light, Gas & Water Division, 411 U.S. 458 (1973), in Permian
22 Basin Rate Cases, 390 U.S. 747 (1968), and most recently in Duquesne Light Co. vs. Barasch,
23 488 U.S. 299 (1989). In the Permian cases, the Supreme Court stressed that a regulatory
24 agency's rate of return order should:

25 "...reasonably be expected to maintain financial integrity, attract necessary capital, and
26 fairly compensate investors for the risks they have assumed..."

27 Therefore, the "end result" of the Commission's decision should be to allow O&R the
28 opportunity to earn a return on equity that is: (1) commensurate with returns on investments in
29 other firms having corresponding risks, (2) sufficient to assure confidence in the Company's

1 financial integrity, and (3) sufficient to maintain the Company's creditworthiness and ability to
2 attract capital on reasonable terms.

3 **Q. HOW IS THE FAIR RATE OF RETURN DETERMINED?**

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

12 While utilities like O&R enjoy varying degrees of monopoly in the sale of public utility
13 services, they must compete with everyone else in the free, open market for the input factors of
14 production, whether they be labor, materials, machines, or capital. The prices of these inputs are
15 set in the competitive marketplace by supply and demand, and it is these input prices that are
16 incorporated in the cost of service computation. This item is just as true for capital as for any
17 other factor of production. Since utilities and other investor-owned businesses must go to the
18 open capital market and sell their securities in competition with every other issuer, there is
19 obviously a market price to pay for the capital they require, for example, the interest on debt
20 capital, or the expected market return on common and/or preferred equity.

21 **Q. HOW DOES THE CONCEPT OF A FAIR RETURN RELATE TO THE CONCEPT OF**
22 **OPPORTUNITY COST?**

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

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

13 **Q. HOW DOES THE COMPANY OBTAIN ITS CAPITAL AND HOW IS ITS OVERALL**
14 **COST OF CAPITAL DETERMINED?**

15 A. The funds employed by the Company are obtained in two general forms, debt capital and equity
16 capital. The latter consists of common equity capital. The cost of debt funds and preferred stock
17 funds can be ascertained easily from an examination of the contractual terms for the interest
18 payments and preferred dividends. The cost of common equity funds, that is, equity investors'
19 required rate of return, is more difficult to estimate because the dividend payments received from
20 common stock are not contractual or guaranteed in nature. They are uneven and risky, unlike
21 interest payments. Once a cost of common equity estimate has been developed, it can then easily
22 be combined with the embedded cost of debt and preferred stock, based on the utility’s capital

structure, in order to arrive at the overall cost of capital.

Q. WHAT IS THE MARKET REQUIRED RATE OF RETURN ON EQUITY CAPITAL?

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

III. COST OF EQUITY ESTIMATES

Q. DR. MORIN, HOW DID YOU ESTIMATE THE FAIR ROE FOR O&R?

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

Q. WHY DID YOU USE MORE THAN ONE APPROACH FOR ESTIMATING THE COST OF EQUITY?

A. No one individual method provides the necessary level of precision for determining a fair return, but each method provides useful evidence to facilitate the exercise of an informed judgment. Reliance on any single method or preset formula is inappropriate when dealing with investor expectations because of possible measurement difficulties and vagaries in individual companies' market data. Examples of such vagaries include dividend suspension, insufficient or unrepresentative historical data due to a recent merger, impending merger or acquisition, and a new corporate identity due to restructuring activities. The advantage of using several different approaches is that the results of each one can be used to check the others.

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

6 As I have stated, there are three broad generic methodologies available to measure the
7 cost of equity: DCF, Risk Premium, and CAPM. All three of these methodologies are accepted
8 and used by the financial community and firmly supported in the financial literature.

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

19 There is no single model that conclusively determines or estimates the expected return for
20 an individual firm. Each methodology has its own way of examining investor behavior, its own
21 premises, and its own set of simplifications of reality. Investors do not necessarily subscribe to
22 any one method, nor does the stock price reflect the application of any one single method by the

1 price-setting investor. Absent any hard evidence as to which method outperforms the other, all
2 relevant evidence should be used, without discounting the value of any results, in order to
3 minimize judgmental error, measurement error, and conceptual infirmities. I submit that a
4 regulatory body should rely on the results of a variety of methods applied to a variety of
5 comparable groups and that no one method should be given more weight than another. There is
6 no guarantee that a single DCF result is necessarily the ideal predictor of the stock price and of
7 the cost of equity reflected in that price, just as there is no guarantee that a single CAPM or Risk
8 Premium result constitutes the perfect explanation of a stock's price or the cost of equity.

IV. RISK PREMIUM ANALYSES

9 **Q. DR. MORIN, PLEASE PROVIDE AN OVERVIEW OF YOUR RISK PREMIUM**
10 **ANALYSES.**

11 A. In order to quantify the risk premium for O&R, I have performed four risk premium studies. The
12 first two studies deal with aggregate stock market risk premium evidence using two versions of the
13 CAPM methodology and the other two studies deal directly with the regulated utility industry.

A. CAPM ESTIMATES

15 **Q. PLEASE DESCRIBE YOUR APPLICATION OF THE CAPM RISK PREMIUM**
16 **APPROACH.**

17 A. My first two risk premium estimates are based on the CAPM and on an empirical approximation
18 to the CAPM (ECAPM). The CAPM is a fundamental paradigm of finance. Simply put, the
19 fundamental idea underlying the CAPM is that risk-averse investors demand higher returns for
20 assuming additional risk, and higher-risk securities are priced to yield higher expected returns
21 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 securities market as a whole by R_M , the CAPM is:

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

This is the seminal CAPM expression, which states that the return required by investors is made up of a risk-free component, R_F , plus a risk premium determined by $\beta(R_M - R_F)$. To derive the CAPM risk premium estimate, three quantities are required: the risk-free rate (R_F), beta (β), and the market risk premium, ($R_M - R_F$). For the risk-free rate, I used 4.2% based on the current level of long-term Treasury interest rates. For beta, I used 0.82 and for the market risk premium (“MRP”), I used 7.4%. These inputs to the CAPM are explained below.

Q. HOW DID YOU DERIVE THE RISK FREE RATE OF 4.2%?

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

The appropriate proxy for the risk-free rate in the CAPM is the return on the longest term Treasury bond possible. This is because common stocks are very long-term instruments more akin to very long-term bonds rather than to short-term or intermediate-term Treasury notes. In a risk premium model, the ideal estimate for the risk-free rate has a term to maturity equal to the security being analyzed. Common stock is a very long-term investment because the cash flows

1 to investors in the form of dividends last indefinitely. Thus, the yield on the longest-term
2 possible government bonds, that is the yield on 30-year Treasury bonds, is the best measure of
3 the risk-free rate for use in the CAPM. The expected common stock return is based on very
4 long-term cash flows, regardless of an individual's holding time period. Moreover, utility asset
5 investments generally have very long-term useful lives and should correspondingly be matched
6 with very long-term maturity financing instruments. Thus the yield on the longest-term possible
7 government bonds, that is the yield on 30-year Treasury bonds, is the best measure of the risk-
8 free rate for use in the CAPM.

9 While long-term Treasury bonds are potentially subject to interest rate risk, this is only
10 true if the bonds are sold prior to maturity. A substantial fraction of bond market participants,
11 usually institutional investors with long-term liabilities (e.g., pension funds, insurance
12 companies), in fact hold bonds until they mature, and therefore are not subject to interest rate
13 risk. Moreover, institutional bondholders neutralize the impact of interest rate changes by
14 matching the maturity of a bond portfolio with the investment planning period, or by engaging in
15 hedging transactions in the financial futures markets. The merits and mechanics of such
16 immunization strategies are well documented by both academicians and practitioners.

17 Another reason for utilizing the longest maturity Treasury bond possible is that common
18 equity has an infinite life span, and the inflation expectations embodied in its market-required
19 rate of return therefore will be equal to the inflation rate anticipated to prevail over the very long-
20 term. The same expectation should be embodied in the risk free rate used in applying the CAPM
21 model. It stands to reason that the actual yields on 30-year Treasury bonds will more closely
22 incorporate within their yield the inflation expectations that influence the prices of common

1 stocks than do short-term or intermediate-term U.S. Treasury notes.

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

7 **Q. DR. MORIN, ARE SHORT-TERM INTEREST RATES APPROPRIATE PROXIES FOR**
8 **THE RISK-FREE RATE IN IMPLEMENTING THE CAPM?**

9 A. No, they are not. Short-term rates are volatile, fluctuate widely, and are subject to more random
10 disturbances than are long-term rates. Short-term rates are largely administered rates. For
11 example, Treasury bills are used by the Federal Reserve as a policy vehicle to stimulate the
12 economy and to control the money supply, and are used by foreign governments, companies, and
13 individuals as a temporary safe-house for money.

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

19 As a conceptual matter, short-term Treasury Bill yields reflect the impact of factors
20 different from those influencing the yields on long-term securities such as common stock. For
21 example, the premium for expected inflation embedded into 90-day Treasury Bills is likely to be
22 far different than the inflationary premium embedded into long-term securities yields. On

1 grounds of stability and consistency, the yields on long-term Treasury bonds match more closely
2 with common stock returns.

3 **Q. WHAT ARE U.S. TREASURY 30-YEAR BONDS CURRENTLY YIELDING?**

4 A. The yield on U.S. Treasury 30-year bonds prevailing in early November 2008, as reported in
5 Value Line and the Federal Reserve Bank, was 4.2%. Accordingly, I shall use 4.2% as my
6 estimate of the risk-free rate component of the CAPM. As I discuss later, while interest rates
7 have decreased in the past year, the cost of borrowing for companies generally and utilities in
8 particular have increased substantially.

9 **Q. HOW DID YOU SELECT THE BETA FOR YOUR CAPM ANALYSIS?**

10 A. A major thrust of modern financial theory as embodied in the CAPM is that perfectly diversified
11 investors can eliminate the company-specific component of risk, and that only market risk
12 remains. The latter is technically known as "beta", or "systematic risk". The beta coefficient
13 measures the change in a security's return relative to that of the market. The beta coefficient
14 states the extent and direction of movement in the rate of return on a stock relative to the
15 movement in the rate of return on the market as a whole. The beta coefficient indicates the
16 change in the rate of return on a stock associated with a one percentage point change in the rate
17 of return on the market, and, thus, measures the degree to which a particular stock shares the risk
18 of the market as a whole. Modern financial theory has established that beta incorporates several
19 economic characteristics of a corporation that are reflected in investors' return requirements.

20 Technically, the beta of a stock is a measure of the covariance of the return on the stock
21 with the return on the market as a whole. Accordingly, it measures dispersion in a stock's return
22 that cannot be reduced through diversification. In abstract theory for a large diversified

1 portfolio, dispersion in the rate of return on the entire portfolio is the weighted sum of the beta
2 coefficients of its constituent stocks.

3 O&R is not publicly traded and, therefore, proxies must be used for O&R. As a first
4 proxy for the Company's beta, I have examined the betas of a sample of widely-traded
5 investment-grade dividend-paying natural gas utilities covered by Value Line with at least 50%
6 of their revenues from natural gas utility operations. This group is examined in more detail later
7 in my testimony, in connection with the DCF estimates of the cost of common equity. As
8 displayed on page 1 of Exhibit No. __ (RAM-2), the average beta for the natural gas group is
9 currently 0.82.

10 In view of the scarcity of publicly-traded pure-play natural gas distributors, I also
11 examined the betas of a sample of widely-traded investment-grade combination gas and electric
12 utilities with at least 50% of their revenues from regulated utility operations as a second proxy
13 for the Company's natural gas business. This group is examined in more detail later in my
14 testimony, in connection with the DCF estimates of the cost of common equity. As shown on
15 page 2 of Exhibit RAM-2, the average beta of the distribution group is also 0.82. Based on these
16 results, I shall use the average beta of the two groups, 0.82, as a beta estimate for O&R's natural
17 gas delivery operations.

18 **Q. WHY DID YOU USE A MRP ESTIMATE OF 7.4% IN YOUR CAPM ANALYSIS?**

19 A. This estimate was based on the results of both historical and forward-looking studies of long-term
20 risk premiums. First, the Ibbotson Associates (now Morningstar) study, Stocks, Bonds, Bills,
21 and Inflation, 2008 Yearbook, compiling historical returns from 1926 to 2007, shows that a
22 broad market sample of common stocks outperformed long-term U. S. Treasury bonds by 6.5%.

1 The historical MRP over the income component of long-term Treasury bonds rather than over
2 the total return is 7.1%. Ibbotson Associates recommend the use of the latter as a more reliable
3 estimate of the historical MRP, and I concur with this viewpoint. The historical MRP should be
4 computed using the income component of bond returns because the intent, even using historical
5 data, is to identify an expected MRP. The more accurate way to estimate the MRP from historic
6 data is to use the income return, not total returns on government bonds, as explained in Ibbotson
7 Associates, Stocks, Bonds, Bills, and Inflation: Valuation Edition, 2008 Yearbook. This is
8 because the income component of total bond return (i.e., the coupon rate) is a far better estimate
9 of expected return than the total return (i.e., the coupon rate + capital gain), as realized capital
10 gains/losses are largely unanticipated by bond investors. The long-horizon (1926-2007) MRP
11 (based on income returns, as required) is specifically calculated to be 7.1% rather than 6.5%.
12 Second, a DCF analysis applied to the aggregate equity market using the S&P 500 Index and
13 Value Line growth forecasts indicates a prospective MRP of 7.7%. Therefore, I shall employ the
14 average of the two estimates, 7.4%, as a reasonable estimate of the MRP.

15 **(1) HISTORICAL MARKET RISK PREMIUM**

16 **Q. WHY DID YOU USE LONG TIME PERIODS IN ARRIVING AT YOUR HISTORICAL**
17 **MRP ESTIMATE?**

18 **A.** Because realized returns can be substantially different from prospective returns anticipated by
19 investors when measured over short time periods, it is important to employ returns realized over
20 long time periods rather than returns realized over more recent time periods when estimating the
21 MRP with historical returns. Therefore, a risk premium study should consider the longest
22 possible period for which data are available. Short-run periods during which investors earned a

1 lower risk premium than they expected are offset by short-run periods during which investors
2 earned a higher risk premium than they expected. Only over long time periods will investor
3 return expectations and realizations converge.

4 I have therefore ignored realized risk premiums measured over short time periods,
5 because they are heavily dependent on short-term market movements. Instead, I relied on results
6 over periods of enough length to smooth out short-term aberrations, and to encompass several
7 business and interest rate cycles. The use of the entire study period in estimating the appropriate
8 MRP minimizes subjective judgment and encompasses many diverse regimes of inflation,
9 interest rate cycles, and economic cycles.

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

15 **Q. ON WHAT MATURITY BOND DOES THE HISTORICAL RISK PREMIUM DATA**
16 **RELY?**

17 A. Because 30-year bonds were not always traded or even available throughout the entire 1926-2007
18 period covered in the Ibbotson Associate Study of historical returns, the latter study relied on
19 bond return data based on 20-year Treasury bonds. To the extent that the normal yield curve is
20 virtually flat above maturities of 20 years over most of the period covered in the Ibbotson study,
21 the difference in yield is not material. In fact, the difference in yield between 30-year and 20-
22 year bonds is actually negative. The average difference in yield over the 1977-2007 period is 13

basis points, that is, the yield on 20-year bonds is slightly higher than the yield on 30-year bonds.

(2) PROSPECTIVE MARKET RISK PREMIUM

Q. PLEASE DESCRIBE YOUR PROSPECTIVE APPROACH IN DERIVING THE MRP IN THE CAPM ANALYSIS.

A. For my prospective estimate of the MRP, I applied a DCF analysis to the aggregate equity market using Value Line's Investment Analyzer ("VLIA") software. The dividend yield on the dividend-paying stocks that make up the S&P 500 Index is currently 2.6% (VLIA 10/2008 edition), and the average projected long-term growth rate in dividends is 9.1%. Adding the dividend yield to the growth component produces an expected return on the aggregate equity market of 11.7%. Following the tenets of the DCF model, the spot dividend yield must be converted into an expected dividend yield by multiplying it by one plus the growth rate. This brings the expected return on the aggregate equity market to 11.9%. Recognition of the quarterly timing of dividend payments rather than the annual timing of dividends assumed in the annual DCF model brings the MRP estimate to approximately 12.1%. Subtracting the risk-free rate of 4.2% from the latter, the implied risk premium is 7.7% over long-term U.S. Treasury bonds.

Q. DID YOU CHECK YOUR MRP ESTIMATE OF 7.4% FROM ANY OTHER SOURCE?

A. Yes, I did. As a check on my final MRP estimate of 7.4%, I examined a 2003 comprehensive article published in Financial Management (see 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). These authors provide estimates of the prospective expected returns for S&P 500 companies over the period 1983-1998. They 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. The prevailing risk-free rate for each year was then subtracted from the expected rate of return for the overall market to arrive at the market risk premium for that year. The table below, drawn from Table 2 of the aforementioned study, displays the average prospective risk premium estimate (Column 2) for each year from 1983 to 1998. The average MRP estimate for the overall period is 7.2%, which is very close to my own estimate of 7.4%.

<u>Year</u>	<u>DCF Market Risk Premium</u>
1983	6.6%
1984	5.3%
1985	5.7%
1986	7.4%
1987	6.1%
1988	6.4%
1989	6.6%
1990	7.1%
1991	7.5%
1992	7.8%
1993	8.2%
1994	7.3%
1995	7.7%
1996	7.8%
1997	8.2%
1998	9.2%
MEAN	7.2%

Q. WHAT IS YOUR RISK PREMIUM ESTIMATE OF O&R'S COST OF EQUITY USING THE CAPM APPROACH?

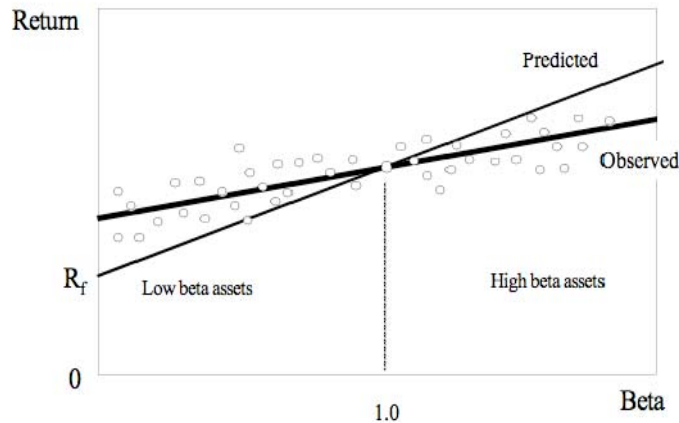
A. Inserting those input values in the CAPM equation, namely a risk-free rate of 4.2%, a beta of 0.82, and a MRP of 7.4%, the CAPM estimate of the cost of common equity for O&R is: $4.2\% + 0.82 \times 7.4\% = 10.3\%$. This estimate becomes 10.6% with flotation costs. The need for a flotation cost

allowance is discussed later in my testimony.

Q. CAN YOU DESCRIBE YOUR APPLICATION OF THE EMPIRICAL VERSION OF THE CAPM?

A. There have been countless empirical tests of the CAPM in the finance literature in order to determine to what extent security returns and betas are related in the manner predicted by the CAPM. This literature is summarized in Chapter 13 of my 1994 book, Regulatory Finance, and Chapter 6 of my latest book, The New Regulatory Finance, both published by Public Utilities Report Inc. The results of the tests support the idea that beta is related to security returns, that the 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. In other words, 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 the symbol alpha, α , represents the "constant" of the risk-return line, 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

1 short-term risk-free rate already incorporates some of the desired effect of using the ECAPM.
2 In other words, the long-term risk-free rate version of the CAPM has a higher intercept and a
3 flatter slope than the short-term risk-free version which has been tested. This is also because
4 the use of adjusted betas rather than the use of raw betas also incorporates some of the
5 desired effect of using the ECAPM. Thus, it is reasonable to apply a conservative alpha
6 adjustment.

7 **Q. IS THE USE OF THE ECAPM CONSISTENT WITH THE USE OF ADJUSTED BETAS?**

8 A. Yes, it is. Some have argued that the use of the ECAPM is inconsistent with the use of adjusted
9 betas, such as those supplied by Value Line. This is because the reason for using the ECAPM is
10 to allow for the tendency of betas to regress toward the mean value of 1.00 over time, and, since
11 Value Line betas are already adjusted for such trend, an ECAPM analysis results in double-
12 counting. This argument is erroneous. Fundamentally, the ECAPM is not an adjustment,
13 increase or decrease, in beta. This is obvious from the fact that the observed return on high beta
14 securities is actually lower than that produced by the CAPM estimate. The ECAPM is a formal
15 recognition that the observed risk-return tradeoff is flatter than predicted by the CAPM based on
16 myriad empirical evidence. The ECAPM and the use of adjusted betas comprised two separate
17 features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still
18 understates the return for low-beta stocks. Even if the ECAPM is used, the return for low-beta
19 securities is understated if the betas are understated. Referring back to the previous graph, the
20 ECAPM is a return (vertical axis) adjustment and not a beta (horizontal axis) adjustment. Both
21 adjustments are necessary. Moreover, the use of adjusted betas compensates for interest rate
22 sensitivity of utility stocks not captured by unadjusted betas, as explained in Appendix A.

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

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

Inserting 4.2% for the risk-free rate R_F , a MRP of 7.4% for $(R_M - R_F)$ and a beta of 0.82 in the above equation, the ROE is 10.6% without flotation costs and 10.9% with flotation costs.

Q. DR. MORIN, PLEASE SUMMARIZE YOUR CAPM ESTIMATES.

The table below summarizes the common equity estimates obtained from my CAPM studies. The average CAPM result is 10.8%.

CAPM	% ROE
CAPM plain	10.6%
Empirical CAPM	10.9%
AVERAGE	10.8%

B. HISTORICAL RISK PREMIUM

Q. CAN YOU DESCRIBE YOUR HISTORICAL RISK PREMIUM ANALYSIS OF THE NATURAL GAS UTILITY INDUSTRY?

Yes. As a proxy for the risk premium applicable to the natural gas utility business, I estimated the historical risk premium for the utility industry with an annual time series analysis applied to the utility industry as a whole over the 1930-2007 period, using *Standard and Poor's Utility Index* as an industry proxy. The analysis is depicted on Exhibit RAM-3. The risk premium was estimated by computing the actual realized return on equity capital for the S&P Utility Index for each year, using the actual year-to-year changes in the index, and then subtracting the long-term

1 government bond return for that year.

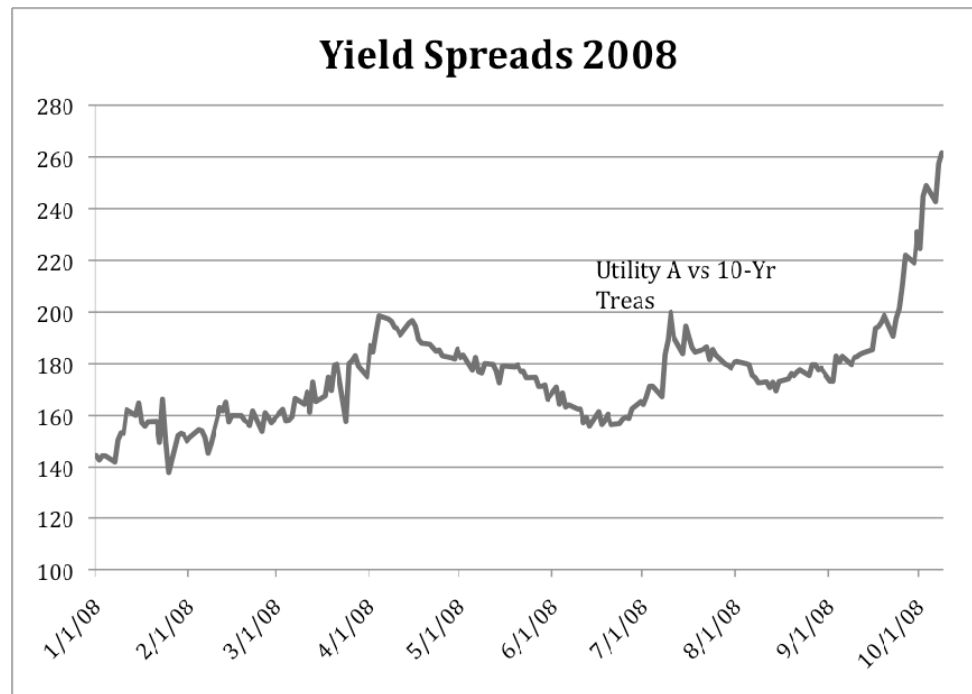
2 As shown on Exhibit RAM-3, the average risk premium over the period was 6.1% over
3 historical long-term Treasury bond returns and 6.3% over long-term Treasury bond yields.
4 Given that the risk-free rate is 4.2%, and using the historical estimate of 6.1%, the implied cost
5 of equity for the average risk utility from this particular method is $4.2\% + 6.1\% = 10.3\%$.

6 In past testimonies, I have relied on the Moody's Electric Utility Index to perform my
7 historical risk premium study. Following the acquisition of Moody's by Mergent in 2002,
8 publication of the electric utility index was discontinued. Therefore, I chose to rely on the S&P
9 Utility Index instead of the Moody's Index in order to ensure continuity and timeliness of the
10 risk premium data. I note that the results using the S&P Index are not materially different from
11 those using the discontinued Moody's index.

12 **Q. WHAT IS CURRENTLY HAPPENING IN THE DEBT AND EQUITY MARKETS?**

13 A. The debt markets have witnessed record high yield spreads (the incremental yield over Treasury
14 rates needed to issued debt) and a more severe differentiation between the spreads charged to
15 companies with different levels of credit. The chart below depicts the rising and record high
16 spreads in recent months for utilities rated single A. Whereas utilities were borrowing money at
17 some 180 basis points over Treasuries, the current spread is 260 basis points, an increase of 80
18 basis points, virtually the same upward increase in the DCF estimates. In terms of market
19 accessibility, the new issuance debt markets and the equity new issuance markets are all but
20 closed. In a nutshell, there is a fundamental structural upward shift in risk aversion as capital
21 markets are re-pricing risk, and capital has become, and will continue to be, more expensive for
22 all market participants.

1



2

3

4 **Q. DR. MORIN, GIVEN THE CURRENT STATE OF THE CAPITAL MARKETS AT THIS**
5 **TIME, IS YOUR HISTORICAL RISK PREMIUM ANALYSIS USING GOVERNMENT**
6 **BOND YIELDS APPROPRIATE?**

7 A. No, I do not believe it is. Trends in utility cost of capital are directly reflected in their cost of debt
8 and are not directly captured by a risk premium estimate tied to government bond yields. This is
9 especially germane in the current financial crisis where corporate spreads have reached record
10 levels, as shown on the graph above. Because a utility's cost of capital is determined by its business
11 and financial risks, it is reasonable to surmise that its cost of equity will track its cost of debt more
12 closely than it will track the government bond yield. To guard against this possibility, I have
13 replicated my historical premium analysis using the utility bond yield instead of the government
14 bond yield.

**Q. CAN YOU DESCRIBE YOUR HISTORICAL RISK PREMIUM ANALYSIS OF THE
NATURAL GAS UTILITY INDUSTRY USING UTILITY BOND YIELDS?**

A. Yes. The same risk premium analysis using Treasury bond yields is replicated on Exhibit RAM-3 page 2, only this time using A-rated utility bond yields. The risk premium was estimated by computing the actual realized return on equity capital for the S&P Utility Index for each year, using the actual year-to-year changes in the index, and then subtracting the long-term A-rated utility bond return for that year.

As shown on page 2 of Exhibit RAM-3, the average risk premium over the period was 5.0% over both utility bond returns and utility bond yields. Given that the current yield on utility bonds rated single A is 7.3%, and using the historical risk premium estimate of 5.0%, the implied cost of equity from this particular method is $7.3\% + 5.0\% = 12.3\%$.

**Q. DID YOU INCORPORATE THIS RESULT INTO YOUR FINAL ROE
RECOMMENDATION?**

A. No, I did not. In the past few months, the financial markets, both in the U.S. and abroad, have become extremely volatile, unpredictable, and have displayed unusual behavior. To illustrate, daily percentage changes in the Dow Jones Industrial Index have experienced unprecedented swings. Moreover, the CBOE Volatility Index ("VIX") which measures the volatility of the S&P 500 Index has increased to record highs. The turmoil in the capital markets is also reflected by highly unusual events, for example, the government bailout of \$700 billion, the bankruptcy of Lehman Brothers and Bear Stearns, and the acquisition of Merrill Lynch by Bank of America. In view of the highly unusual circumstances that have characterized capital markets recently, I did not incorporate the 12.3% result into my recommendation. To the extent that the financial

1 crisis persists over the next several months, I shall incorporate that particular result into my final
2 ROE recommendation.

3 **Q. DR. MORIN, ARE RISK PREMIUM STUDIES WIDELY USED?**

4 A. Yes, they are. Risk Premium analyses are widely used by analysts, investors, economists, and
5 expert witnesses. Most college-level corporate finance and/or investment management texts,
6 including Investments by Bodie, Kane, and Marcus, McGraw-Hill Irwin, 2002, which is a
7 recommended textbook for CFA (Chartered Financial Analyst) certification and examination,
8 contain detailed conceptual and empirical discussion of the risk premium approach. The latter is
9 typically recommended as one of the three leading methods of estimating the cost of capital.
10 Professor Brigham's best-selling corporate finance textbooks, for example, Corporate Finance: A
11 Focused Approach, 3rd ed., South-Western, 2008, recommends the use of risk premium studies,
12 among others. Techniques of risk premium analysis are widespread in investment community
13 reports. Professional certified financial analysts are certainly well versed in the use of this
14 method.

15 **Q. ARE THE ASSUMPTIONS THAT UNDERLIE THE HISTORICAL RISK PREMIUM**
16 **METHODOLOGY REALISTIC?**

17 A. Yes, I believe they are. I also believe that they are no more restrictive than the assumptions that
18 underlie the DCF model or the CAPM. While it is true that the method looks backward in time
19 and assumes that the risk premium is constant over time, these assumptions are not necessarily
20 restrictive. By employing returns realized over long time periods rather than returns realized
21 over more recent time periods, investor return expectations and realizations converge. Realized
22 returns can be substantially different from prospective returns anticipated by investors, especially

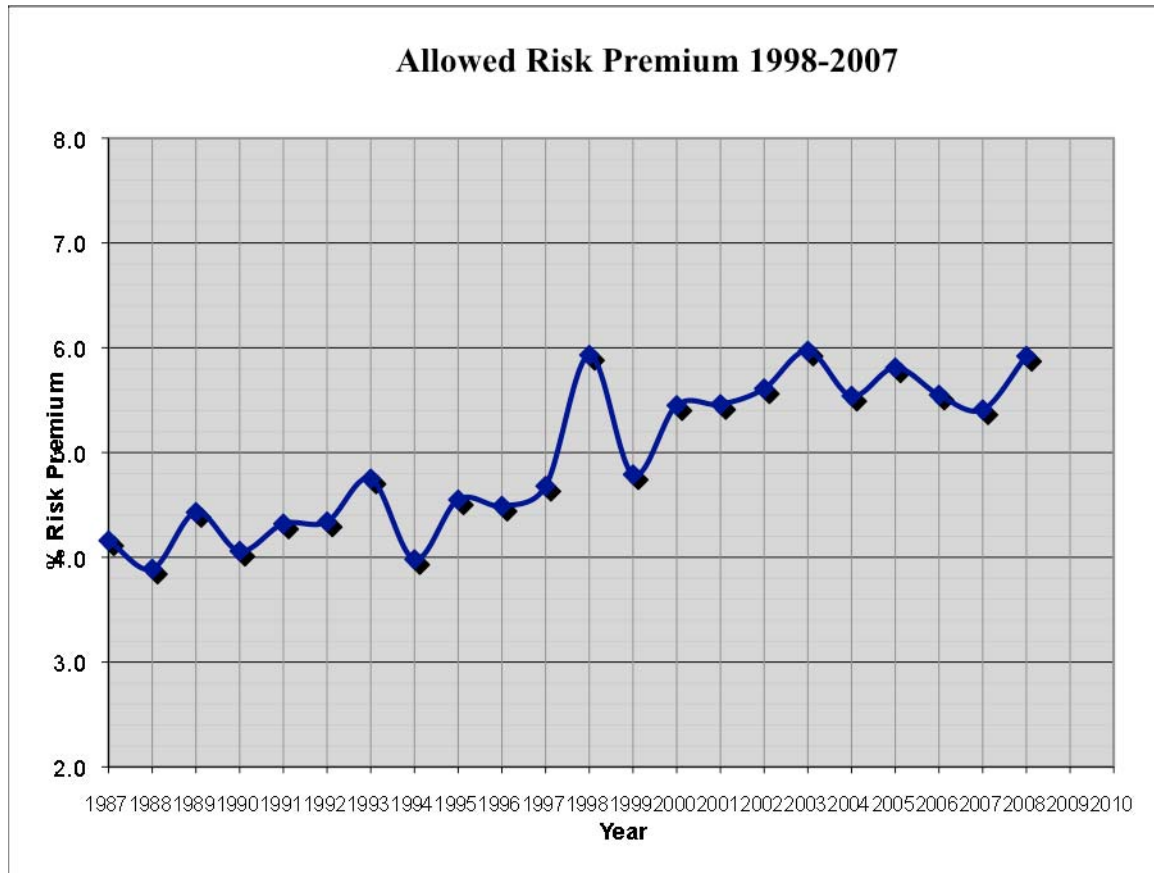
1 when measured over short time periods. By ensuring that the risk premium study encompasses
2 the longest possible period for which data are available, short-run periods during which
3 investors earned a lower risk premium than they expected are offset by short-run periods during
4 which investors earned a higher risk premium than they expected. Only over long time periods
5 will investor return expectations and realizations converge, or else, investors would never invest
6 any money.

7 **C. ALLOWED RISK PREMIUMS**

8 **Q. CAN YOU DESCRIBE YOUR ANALYSIS OF ALLOWED RISK PREMIUMS IN THE**
9 **NATURAL GAS UTILITY INDUSTRY**

10 A. To estimate the natural gas utility industry's cost of common equity, I also examined the
11 historical risk premiums implied in the ROEs allowed by regulatory commissions for natural gas
12 utilities over the last decade relative to the contemporaneous level of the long-term Treasury
13 bond yield. This variation of the risk premium approach is reasonable because allowed risk
14 premiums are presumably based on the results of market-based methodologies (DCF, Risk
15 Premium, CAPM, *etc.*) presented to regulators in rate hearings and on the actions of objective
16 unbiased investors in a competitive marketplace. Historical allowed ROE data are readily
17 available over long periods on a quarterly basis from Regulatory Research Associates (now SNL
18 Energy) and easily verifiable from SNL publications and past commission decision archives.

19 The average ROE spread over long-term Treasury yields was 5.0% over the entire 1987-
20 2008 period and 5.6% for the last 1999-2008 decade. The graph below shows the year-by-year
21 allowed risk premium. The escalating trend of the risk premium in response to lower interest
22 rates and rising competition is noteworthy.



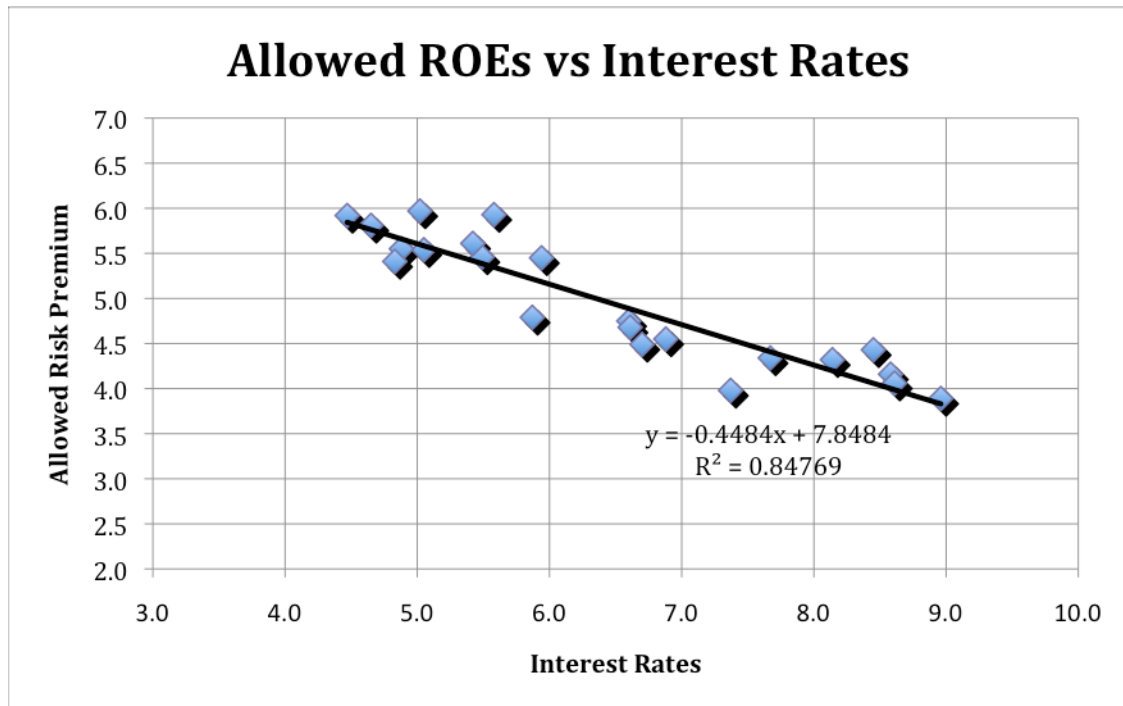
A careful review of these ROE decisions relative to interest rate trends over the 1987-2008 period reveals a narrowing of the risk premium in times of rising interest rates, and a widening of the premium as interest rates fall. The following statistical relationship between the risk premium (RP) and interest rates (YIELD) emerges over the last decade:

$$RP = 7.484 - 0.4484 \text{ YIELD} \quad R^2 = 0.85$$

The relationship is highly statistically significant¹ as indicated by the very high R^2 . The graph below shows a clear inverse relationship between the allowed risk premium and interest

¹ The coefficient of determination R^2 , sometimes called the “goodness of fit measure” is a measure of the degree of explanatory power of a statistical relationship. It is simply the ratio of the explained portion to the total sum of squares. The higher R^2 the higher is the degree of the overall fit of the estimated regression equation to the sample data. The t-statistic is a standard measure of the statistical significance of an independent variable in a regression relationship. A t-value above 2.0 is considered highly significant.

rates as revealed in past ROE decisions.



Inserting the current long-term Treasury bond yield of 4.2% in the above equation suggests that a risk premium estimate of 6.0% should be allowed for the average risk natural gas utility, implying a cost of equity of 10.2% for the average risk utility. I note that the latter estimate is nearly identical to that obtained from the historical risk premium study of the utility industry.

Q. DO INVESTORS TAKE INTO ACCOUNT ALLOWED RETURNS IN FORMULATING THEIR RETURN EXPECTATIONS?

A. Yes, they do. Investors do take into account returns granted by various regulators in formulating their risk and return expectations, as evidenced by the availability of commercial publications disseminating such data, including Value Line and Regulatory Research Associates (now SNL Energy). Allowed returns, while certainly not a precise indication of a particular company's cost

of equity capital, are nevertheless an important determinant of investor growth perceptions and investor expected returns.

Q. PLEASE SUMMARIZE YOUR RISK PREMIUM ESTIMATES.

A. The table below summarizes the ROE estimates obtained from the two risk premium studies. The average risk premium result is 10.25%, rounded to 10.3%.

Risk Premium Method	ROE
Historical Risk Premium	10.3%
Allowed Risk Premium	10.2%

C. DCF ESTIMATES

Q. PLEASE DESCRIBE THE DCF APPROACH TO ESTIMATING THE COST OF EQUITY CAPITAL.

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

$$K_e = D_1/P_0 + g$$

where: K_e = investors' expected return on equity.

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

P_0 = current stock price.

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

1 The standard DCF formula states that under certain assumptions, which are described in
2 the next paragraph, the equity investor's expected return, K_e , can be viewed as the sum of an
3 expected dividend yield, D_1/P_0 , plus the expected growth rate of future dividends and stock price,
4 g . The returns anticipated at a given market price are not directly observable and must be
5 estimated from statistical market information. The idea of the market value approach is to infer
6 ' K_e ' from the observed share price, the observed dividend, and an estimate of investors' expected
7 future growth.

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

16 **Q. HOW DID YOU ESTIMATE O&R'S COST OF EQUITY WITH THE DCF MODEL?**

17 A. I applied the DCF model to two proxy groups of companies for O&R's natural gas delivery
18 operations: a group consisting of investment-grade dividend-paying natural gas utilities and a
19 group consisting of investment-grade dividend-paying combination gas and electric utilities. In
20 the case of both groups, the companies had to derive at least 50% of their revenues from
21 regulated energy operations.

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

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

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

18 **Q. HOW DID YOU ESTIMATE THE GROWTH COMPONENT OF THE DCF MODEL?**

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

1 As proxies for expected growth, I examined growth estimates developed by professional
2 analysts employed by large investment brokerage institutions. Projected long-term growth rates
3 actually used by institutional investors to determine the desirability of investing in different
4 securities influence investors' growth anticipations. These forecasts are made by large reputable
5 organizations, and the data are readily available to investors and are representative of the
6 consensus view of investors. Because of the dominance of institutional investors in investment
7 management and security selection, and their influence on individual investment decisions,
8 analysts' growth forecasts influence investor growth expectations and provide a sound basis for
9 estimating the cost of equity with the DCF model. Growth rate forecasts of analysts are
10 available from published investment newsletters and from systematic compilations of analysts'
11 forecasts, such as those tabulated by Zacks Investment Research Inc. ("Zacks"). I used analysts'
12 long-term growth forecasts contained in Zacks as proxies for investors' growth expectations in
13 applying the DCF model. I also used Value Line's growth forecast as a proxy.

14 **Q. WHY DID YOU REJECT THE USE OF HISTORICAL GROWTH RATES IN**
15 **APPLYING THE DCF MODEL TO UTILITIES?**

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

19 **Q. DID YOU CONSIDER ANY OTHER METHOD OF ESTIMATING EXPECTED**
20 **GROWTH IN THE DCF MODEL?**

21 A. Yes, I did. I considered using the so-called "sustainable growth" method, also referred to as the
22 "retention growth" method. According to this method, future growth is estimated by multiplying

the fraction of earnings expected to be retained by the company, 'b', by the expected return on book equity, 'ROE', as follows:

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

where: g = expected growth rate in earnings/dividends

b = expected retention ratio

ROE = expected return on book equity

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

Q. DID YOU CONSIDER DIVIDEND GROWTH IN APPLYING THE DCF MODEL?

A. No, not at this time. The reason is that it is widely expected that utilities will continue to lower their dividend payout ratio over the next several years. In other words, earnings are expected to grow faster than dividends in the future.

Whenever the dividend payout ratio is expected to change, the intermediate growth rate in dividends cannot equal the long-term growth rate, because dividend/earnings growth must

1 adjust to the changing payout ratio. The assumptions of constant perpetual growth and constant
2 payout ratio are clearly not met. Thus, the implementation of the standard DCF model is of
3 questionable relevance in this circumstance.

4 Dividend growth rates are unlikely to provide a meaningful guide to investors' growth
5 expectations for utilities in general. This result is because utilities' dividend policies have
6 become increasingly conservative as business risks in the industry have intensified steadily.
7 Dividend growth has remained largely stagnant in past years as utilities are increasingly
8 conserving financial resources in order to hedge against rising business risks. As a result,
9 investors' attention has shifted from dividends to earnings. Therefore, earnings growth provides
10 a more meaningful guide to investors' long-term growth expectations. Indeed, it is growth in
11 earnings that will support future dividends and share prices.

12 **Q. IS THERE ANY EMPIRICAL EVIDENCE DOCUMENTING THE IMPORTANCE OF**
13 **EARNINGS IN EVALUATING INVESTORS' EXPECTATIONS IN THE INVESTMENT**
14 **COMMUNITY?**

15 A. Yes, there is an abundance of evidence attesting to the importance of earnings in assessing
16 investors' expectations. First, the sheer volume of earnings forecasts available from the
17 investment community relative to the scarcity of dividend forecasts attests to their importance.
18 To illustrate, Value Line, Zacks Investment, First Call Thompson, and Multex provide
19 comprehensive compilations of investors' earnings forecasts, to name some. The fact that these
20 investment information providers focus on growth in earnings rather than growth in dividends
21 indicates that the investment community regards earnings growth as a superior indicator of future

1 long-term growth. Second, Value Line's principal investment rating assigned to individual
2 stocks, Timeliness Rank, is based primarily on earnings, which account for 65% of the ranking.

3 **Q. WHAT DCF RESULTS DID YOU OBTAIN FOR THE NATURAL GAS UTILITIES**
4 **GROUP USING ANALYSTS' GROWTH FORECASTS?**

5 A. As a proxy for O&R's natural gas business, I have examined the expected returns of investment-
6 grade dividend-paying natural gas distribution utilities contained in Value Line's natural gas
7 distribution universe with a market value in excess of \$500 million and with at least 50% of their
8 revenues from regulated natural gas operations. The group is shown in Exhibit RAM-4.

9 As shown on Column 2 of Exhibit RAM-4, the average long-term growth forecast
10 obtained from the Zacks corporate earnings database is 6.89% for the natural gas distribution
11 group. Combining this growth rate with the average expected dividend yield of 3.97% shown in
12 Column 3 produces an estimate of equity costs of 10.86% for the gas distribution group shown in
13 Column 4. Recognition of flotation costs brings the cost of equity estimate to 11.07%, shown in
14 Column 5.

15 Repeating the exact same procedure, only this time using Value Line's long-term
16 earnings growth forecast of 5.11% instead of the Zacks consensus growth forecast, the cost of
17 equity for gas distribution group is 9.01%, unadjusted for flotation costs. Adding an allowance
18 for flotation costs brings the cost of equity estimate to 9.22%. This analysis is displayed on
19 Exhibit RAM-5.

20 **Q. PLEASE DESCRIBE YOUR SECOND PROXY GROUP FOR THE COMPANY'S**
21 **NATURAL GAS DISTRIBUTION BUSINESS?**

22 A. It is reasonable to postulate that the Company's natural gas utility operations possess an

1 investment risk profile similar to the combination gas and electric utility business. Combination
2 gas and electric utilities are reasonable proxies for natural gas distribution utilities, for they
3 possess economic characteristics very similar to those of natural gas utilities. They are both
4 involved in the transmission-distribution of energy services products at regulated rates in a
5 cyclical and weather-sensitive market. They both employ a capital-intensive network with
6 similar physical characteristics. They are both subject to rate of return regulation and have
7 enjoyed virtually identical allowed rates of return, attesting to their risk comparability.

8 For my second proxy group of companies, I have therefore examined a group of
9 investment-grade dividend-paying utilities designated as combination gas and electric utilities by
10 AUS Utility Reports and covered in Value Line. Companies with less than 50% of their
11 revenues from regulated operations were eliminated. The same group utilized earlier in
12 connection with beta estimates was retained for the DCF analysis.

13 **Q. WHAT DCF RESULTS DID YOU OBTAIN FOR THE COMBINATION GAS &**
14 **ELECTRIC UTILITIES GROUP USING VALUE LINE GROWTH PROJECTIONS?**

15 A. As shown on Column 2 of Exhibit RAM-6, the average long-term growth forecast obtained from
16 Value Line is 7.30% for this group. No growth projection was available for Duke Energy.
17 Combining this growth rate with the average expected dividend yield of 4.50% shown in Column
18 3 produces an estimate of equity costs of 11.80% for the group, unadjusted for flotation costs.
19 Adding an allowance for flotation costs to the results of Column 4 brings the cost of equity
20 estimate to 12.04%, shown in Column 5.

Q. WHAT DCF RESULTS DID YOU OBTAIN FOR THE COMBINATION GAS & ELECTRIC UTILITIES GROUP USING THE ANALYST'S CONSENSUS GROWTH FORECAST?

A. Using the median consensus analysts' earnings growth forecast published by Zacks of 7.67% instead of the Value Line forecast, the cost of equity for the group is 11.81%. Allowance for flotation costs brings the cost of equity estimate to 12.09%. This analysis is shown on Exhibit RAM-7. No analysts' growth forecasts were available from Zacks for Empire District, MGE Energy, and UniSource .

PLEASE SUMMARIZE YOUR DCF ESTIMATES.

A. The table below summarizes my DCF estimates for O&R. The average DCF estimate is 11.1% and 11.73% without the outlying estimate of 9.2%. It is clear from this table that the DCF estimate of 9.2% derived from the natural gas group using Value Line growth forecast is an outlier.

DCF STUDY	ROE
Natural Gas Utilities Value Line Growth	9.2%
Natural Gas Utilities Zacks Growth	11.1%
Combination Gas & Elec Utilities Value Line Growth	12.0%
Combination Gas & Elec Utilities Zacks Growth	12.1%
Average	11.1%

DR. MORIN, PLEASE NOW TURN TO THE NEED FOR A FLOTATION COST ALLOWANCE.

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

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

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

16 Investors must be compensated for flotation costs on an ongoing basis to the extent that
17 such costs have not been expensed in the past, and therefore the adjustment must continue for the
18 entire time that these initial funds are retained in the firm. Appendix B to my testimony
19 discusses flotation costs in detail, and shows: (1) why it is necessary to apply an allowance of 5%
20 to the dividend yield component of equity cost by dividing that yield by 0.95 (100% - 5%) to
21 obtain the fair return on equity capital; (2) why the flotation adjustment is permanently required
22 to avoid confiscation even if no further stock issues are contemplated; and (3) that flotation costs

1 are only recovered if the rate of return is applied to total equity, including retained earnings, in
2 all future years.

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

13 A simple example will illustrate the concept. A stock is sold for \$100, and investors
14 require a 10% return, that is, \$10 of earnings. But if flotation costs are 5%, the Company nets
15 \$95 from the issue, and its common equity account is credited by \$95. In order to generate the
16 same \$10 of earnings to the shareholders, from a reduced equity base, it is clear that a return in
17 excess of 10% must be allowed on this reduced equity base, here 10.52%.

18 According to the empirical finance literature discussed in Appendix B, total flotation
19 costs amount to 4% for the direct component and 1% for the market pressure component, for a
20 total of 5% of gross proceeds. This in turn amounts to approximately 30 basis points, depending
21 on the magnitude of the dividend yield component. To illustrate, dividing the average expected
22 dividend yield of approximately 5.0% for utility stocks by 0.95 yields 5.3%, which is 30 basis

1 points higher.

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

11 There are several sources of equity capital available to a firm including: common equity
12 issues, conversions of convertible preferred stock, dividend reinvestment plan, employees'
13 savings plan, warrants, and stock dividend programs. Each item carries its own set of
14 administrative costs and flotation cost components, including discounts, commissions, corporate
15 expenses, offering spread, and market pressure. The flotation cost allowance is a composite
16 factor that reflects the historical mix of sources of equity. The allowance factor is a build-up of
17 historical flotation cost adjustments associated and traceable to each component of equity at its
18 source. It is impractical and prohibitively costly to start from the inception of a company and
19 determine the source of all present equity. A practical solution is to identify general categories
20 and assign one factor to each category. My recommended flotation cost allowance is a weighted
21 average cost factor designed to capture the average cost of various equity vintages and types of
22 equity capital raised by the Company.

1 **Q. IS A FLOTATION COST ADJUSTMENT REQUIRED FOR AN OPERATING**
2 **SUBSIDIARY LIKE O&R THAT DOES NOT TRADE PUBLICLY?**

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

V. SUMMARY OF COST OF EQUITY RECOMMENDATION

10 **Q. PLEASE SUMMARIZE YOUR RESULTS AND RECOMMENDATION.**

11 A. To arrive at my final recommendation, I performed four risk premium analyses. For the first two
12 risk premium studies, I applied the CAPM and an empirical approximation of the CAPM using
13 current market data. The other two risk premium analyses were performed on historical risk
14 premium data from natural gas and electric utility industry aggregate data. I also performed DCF
15 analyses on two surrogates for the Company's natural gas delivery business. They are: a group
16 of investment-grade natural gas distribution utilities and a group of investment-grade
17 combination gas and electric utilities. The results from all the various tests are summarized in the
18 table below.

1	METHODOLOGY	ROE
	CAPM	10.6%
	Empirical CAPM	10.9%
	Historical Risk Premium Electric	10.3%
	Allowed Risk Premium	10.2%
	DCF Natural Gas Utilities Value Line Growth	
	DCF Natural Gas Utilities Zacks Growth	11.1%
	DCF Combination Gas & Elec Utilities Value Line Growth	12.0%
	DCF Combination Gas & Elec Utilities Zacks Growth	12.1%

2

3 The overall average results from all the tests is 11.0% as well as the truncated average. The average
4 results from the three principal methodologies are as follows:

5		
6	CAPM	10.8%
7	Risk Premium	10.3%
8	DCF	<u>11.7%</u>
9	AVERAGE	10.9%
10	MIDPOINT	11.0%
11		

12 The results range from a low of 10.3% to a high of 11.8% with a midpoint of 11.0%. Based
13 on these results, I believe that 11.0% is a reasonable, albeit conservative, estimate of the Company's
14 cost of common equity.

15

16 **Q. DR. MORIN, WHAT IS YOUR FINAL CONCLUSION REGARDING O&R'S COST OF**
17 **COMMON EQUITY CAPITAL?**

18 A. Based on the results of all my analyses, the application of my professional judgment, and the risk
19 circumstances of O&R, it is my opinion that a just and reasonable return on the common equity
20 capital of O&R's natural gas utility operations in the state of New York is 11.0%. Currently,
21 capital markets are in a state of turmoil. It is important to note that my recommended return

1 assumes that more stable circumstances will return to capital markets. However, the current
2 market circumstances are anything but normal as I discussed earlier, and I deem my 11.0% ROE
3 recommendation as barebones and extremely conservative.

4 **Q. WOULD YOU NOW DISCUSS THE IMPLICATIONS FOR THE ALLOWED RETURN**
5 **ON EQUITY OF A STAYOUT FOR O&R?**

6 A. The Company has informed me that it will be proposing a three-year rate plan. This exposes
7 O&R to the risk that the cost of equity may go up during the course of the rate plan, without the
8 Company having an opportunity to reset the allowed return to reflect such an increase. It seems
9 likely that upward changes in interest rates may be more likely than downward changes. I am
10 informed that in the past, the Commission has used the differential between 3-year and 1-year
11 Treasury securities to provide guidance as to what the “stayout premium” in such circumstances
12 should be. More specifically, I am informed that in the past the Commission has used one-half
13 of the five-year average differential between (1) a Treasury security reflecting the length of the
14 rate plan and (2) a 1-year Treasury security. The five-year average differential, through the end
15 of October 2008, between 3-year and 1-year Treasury securities is approximately 50 basis points.
16 However, given the highly volatile and unsettled condition in the debt markets and given the
17 unprecedented rise in utility debt costs documented earlier, the yield differential between 3-year
18 and 1-year A-minus rated utilities is a far more representative and appropriate stayout premium.
19 The current spread is 68 basis points while the six-month average differential is 71 basis points.
20 Thus, a stayout premium of 71 basis points would be reasonable for O&R, albeit conservative in
21 the current volatile financial environment.

22 **Q. DR. MORIN, WHAT CAPITAL STRUCTURE ASSUMPTION UNDERLIES YOUR**

1 **RECOMMENDED RETURN ON O&R'S COMMON EQUITY CAPITAL?**

2 A. My recommended ROE for O&R is predicated on the adoption of a test year capital structure
3 consisting of approximately 48% common equity capital.

4 **Q. DID YOU EXAMINE THE REASONABLENESS OF THE COMPANY'S RATE YEAR**
5 **CAPITAL STRUCTURE?**

6 A. Yes, I did. I have compared O&R's rate year capital structure with: 1) the capital structures
7 adopted by regulators for gas utilities, and 2) the actual capital structures of natural gas utilities.

8 The October 2008 edition of Regulatory Research Associates' "*Regulatory Focus: Major*
9 *Rate Case Decisions*" reports an average percentage of common equity in the adopted capital
10 structure of 48.4% for gas utilities for 2007 and 51.4% for 2008 year-to-date. I have also
11 examined the actual capital structures of my comparable group of natural gas utilities as reported
12 by Value Line. The average common equity ratio for the group is 48.5%. I conclude that the
13 Company's common equity ratio of 48% is very reasonable for ratemaking purposes.

14
15 If the Commission was to impute a capital structure consisting of substantially more
16 (less) debt than the rate year capital structure, the higher (lower) common equity cost rate related
17 to a changed common equity ratio should be reflected in the approach. If the Commission
18 ascribes a capital structure different from the rate year capital structure, which imputes a higher
19 debt amount for example, the repercussions on equity costs must be recognized. It is a
20 rudimentary tenet of basic finance that the greater the amount of financial risk borne by common
21 shareholders, the greater the return required by shareholders in order to be compensated for the
22 added financial risk imparted by the greater use of debt financing. In other words, the greater the

1 debt ratio, the greater is the return required by equity investors. Both the cost of incremental
2 debt and the cost of equity must be adjusted to reflect the additional risk associated with the
3 more debt-heavy capital structure. Lower common equity ratios imply greater risk and higher
4 capital cost, and conversely.

5 Several researchers have studied the relationship between the cost of capital, capital-
6 structure changes, and the value of the firm's securities.² The results of these studies indicate
7 that when the debt ratio increases from 40% to 50%, required equity returns increase between 34
8 to 237 basis points. The empirical studies indicate an average increase of 76 basis points, or
9 7.6 basis points per one percentage point increase in the debt ratio. The theoretical studies
10 indicate an average increase of 138 basis points, or 13.8 basis points per one percentage point
11 increase in the debt ratio. In other words, equity return requirements increase between 7.6 and
12 13.8 basis points for each increase in the debt ratio by one percentage point, and more recent
13 studies indicate that the upper end of that range is more indicative of the repercussions on
14 required equity returns.

15 To illustrate, if the Commission were to impute a common equity ratio of 45% for
16 example compared to the average equity ratio for the industry is 50%, a difference of 5%, the
17 above-described research indicates that the ROE should be adjusted upward by approximately 38
18 basis points (7.6×5) to 69 basis points (13.8×5) to reflect the more leveraged capital structure,
19 with a midpoint slightly in excess of 50 basis points.

20 **Q. DID YOU ADJUST YOUR FINAL RECOMMENDATION IN ORDER TO ACCOUNT**
21 **FOR THE COMPANY'S REQUESTED REVENUE DECOUPLING MECHANISM?**

² See Roger A. Morin, *The New Regulatory Finance* (2006) Chapter 16 section 16-4 for a summary of the comprehensive and rigorous empirical studies of the relationship between cost of capital and leverage for public utilities.

1 A. No, I did not. Any risk-mitigating impact such a mechanism could have on the Company's risk
2 profile is already reflected in the capital market data of the comparable gas companies. Because
3 most, if not all, of the gas companies in my comparable group possess some form of revenue
4 decoupling mechanism, it is unnecessary to account for the presence of such a mechanism on the
5 Company's ROE.

6 **Q. FINALLY, DR. MORIN, IF CAPITAL MARKET CONDITIONS CHANGE**
7 **SIGNIFICANTLY BETWEEN THE DATE OF FILING YOUR PREPARED**
8 **TESTIMONY AND THE DATE YOUR ORAL TESTIMONY IS PRESENTED, WOULD**
9 **THIS CAUSE YOU TO REVISE YOUR ESTIMATED COST OF EQUITY?**

10 A. Yes. Interest rates and security prices do change over time, and risk premiums change also,
11 although much more sluggishly. If substantial changes were to occur between the filing date and
12 the time my oral testimony is presented, I will update my testimony accordingly.

13 **Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

14 A. Yes, it does.

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:

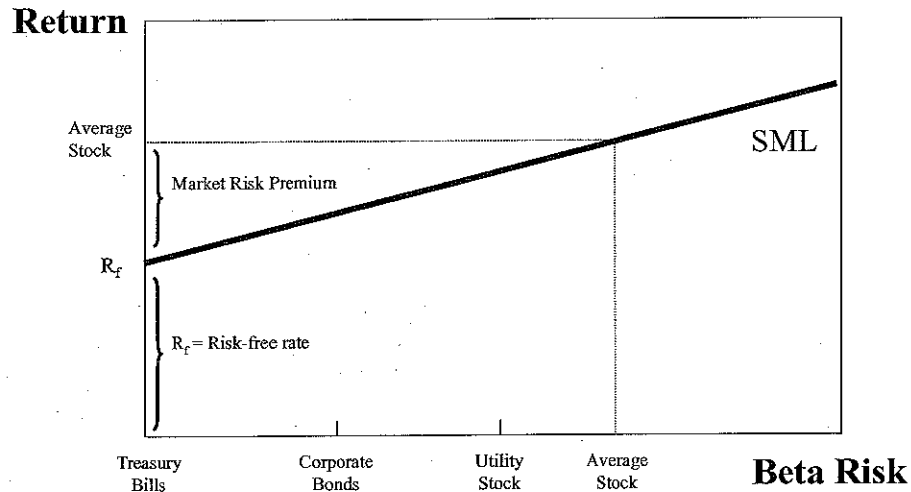
$$K = R_F + \beta(R_M - R_F) \quad (1)$$

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.

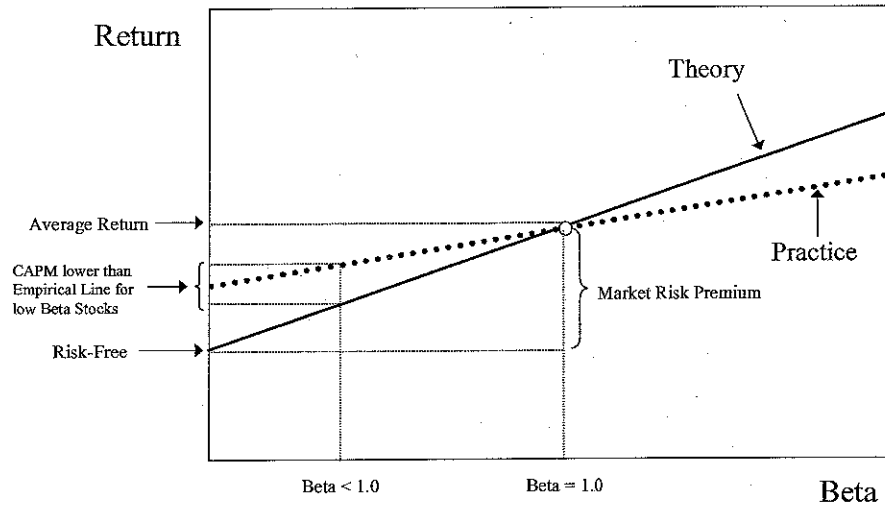
CAPM and Risk - Return in Capital Markets



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:

$$K = R_F + a + \beta (MRP - a) \quad (3)$$

where a 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, $a = a \times MRP$

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:

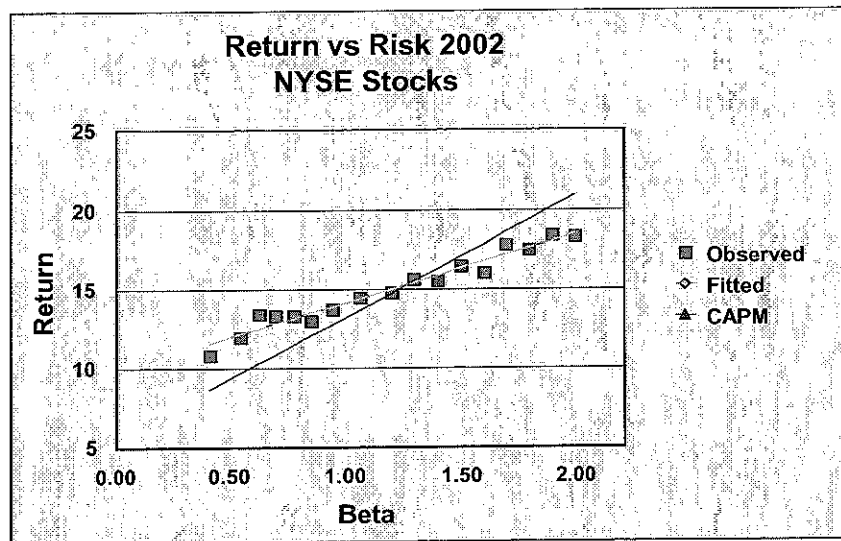
$$K = .0829 + .0520 \beta$$

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.

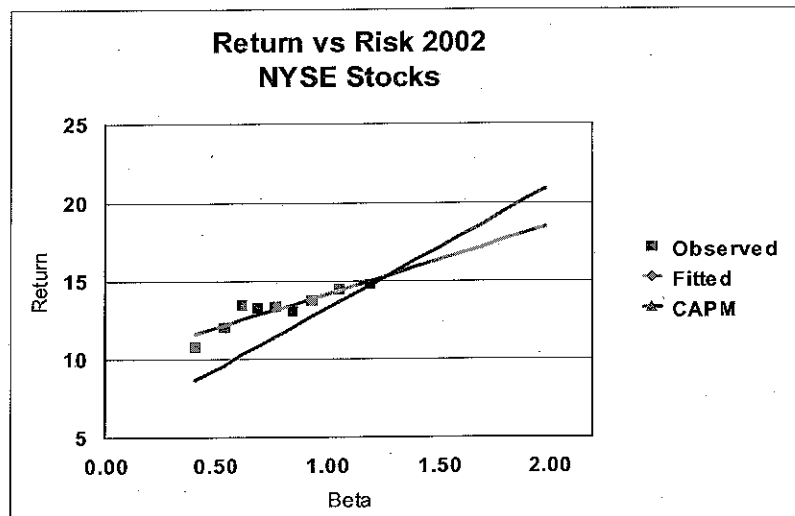
CAPM vs ECAPM



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.

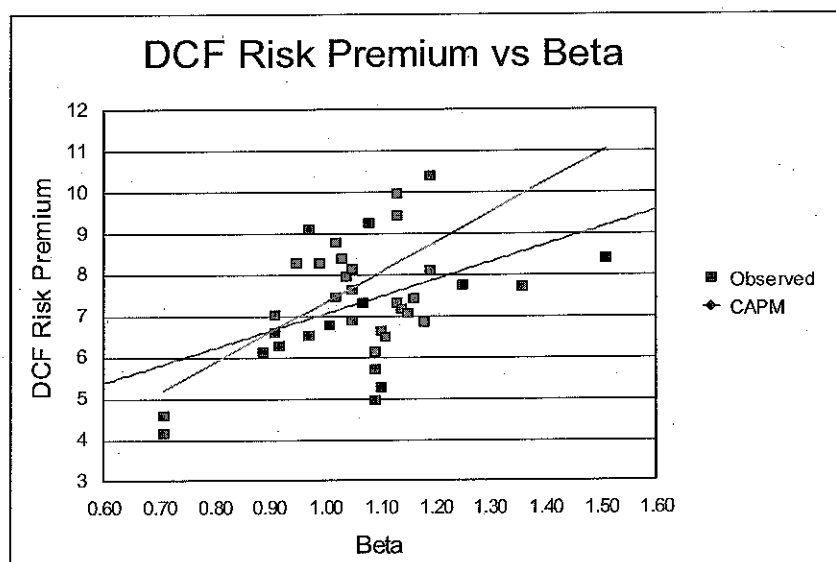
Table A-1 Risk Premium and Beta Estimates by Industry

	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	Telc	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:

$$K = R_F + a + \beta (MRP - a) \quad (5)$$

or, alternatively by the following equivalent relationship:

$$K = R_F + a MRP + (1-a) \beta MRP \quad (6)$$

The empirical findings support values of a 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:

$$\begin{aligned} K &= R_F + a + \beta (MRP - a) \\ K &= 5\% + 2\% + 0.80(7\% - 2\%) \\ &= 11\% \end{aligned}$$

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:

$$P - fP = B_o$$

$$P(1 - f) = B_0$$

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%**
 $(D/P(1-f) + g)$

	COMMON	RETAINED	TOTAL	STOCK	MARKET/ BOOK			
	STOCK	EARNINGS	EQUITY	PRICE	RATIO	EPS	DPS	PAYOUT
Yr	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(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%	

	COMMON	RETAINED	TOTAL	STOCK	MARKET/ BOOK	EPS	DPS	PAYOUT
Yr	STOCK	EARNINGS	EQUITY	PRICE	RATIO	(6)	(7)	(8)
	(1)	(2)	(3)	(4)	(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%

4.53%

4.53%

**NATURAL GAS DISTRIBUTION UTILITIES
BETA ESTIMATES**

Company Name	Beta
1 AGL Resources	0.85
2 Atmos Energy	0.80
3 Laclede Group	0.80
4 Nicor Inc.	0.90
5 Northwest Nat. Gas	0.75
6 Piedmont Natural Gas	0.80
7 South Jersey Inds.	0.80
8 Southwest Gas	0.80
9 WGL Holdings Inc.	0.85
AVERAGE	0.82

Source: VLIA 10/2008

**COMBINATION GAS & ELECTRIC UTILITIES
BETA ESTIMATES**

Company Name	Beta
1 Alliant Energy	0.80
2 Ameren Corp.	0.80
3 Avista Corp.	0.85
4 CMS Energy Corp.	0.95
5 Consol. Edison	0.75
6 DTE Energy	0.75
7 Duke Energy	
8 Empire Dist. Elec.	0.80
9 Entergy Corp.	0.80
10 Exelon Corp.	0.85
11 MGE Energy	0.85
12 Northeast Utilities	0.75
13 NSTAR	0.80
14 Pepco Holdings	0.90
15 PG&E Corp.	0.85
16 PNM Resources	0.90
17 PPL Corp.	0.85
18 Public Serv. Enterprise	0.85
19 Puget Energy Inc.	0.80
20 Sierra Pacific Res.	0.95
21 TECO Energy	0.85
22 UniSource Energy	0.70
23 Wisconsin Energy	0.75
24 Xcel Energy Inc.	0.75
AVERAGE	0.82

Source: VLIA 10/2008

Electric Industry Historical Risk Premium

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
		Long-Term	20 year				S&P	Utility	Utility
		Government	Maturity			Bond	Utility	Equity	Equity
		Bond	Bond			Total	Index	Premium	Premium
Line No.	Year	Yield	Value	Gain/Loss	Interest	Return	Return	Over Bond Returns	Over Bond Yields
1	1931	4.07%	1,000.00						
2	1932	3.15%	1,135.75	135.75	40.70	17.64%	-0.54%	-18.18%	-3.69%
3	1933	3.36%	969.60	-30.40	31.50	0.11%	-21.87%	-21.98%	-25.23%
4	1934	2.93%	1,064.73	64.73	33.60	9.83%	-20.41%	-30.24%	-23.34%
5	1935	2.76%	1,025.99	25.99	29.30	5.53%	76.63%	71.10%	73.87%
6	1936	2.55%	1,032.74	32.74	27.60	6.03%	20.69%	14.66%	18.14%
7	1937	2.73%	972.40	-27.60	25.50	-0.21%	-37.04%	-36.83%	-39.77%
8	1938	2.52%	1,032.83	32.83	27.30	6.01%	22.45%	16.44%	19.93%
9	1939	2.26%	1,041.65	41.65	25.20	6.68%	11.26%	4.58%	9.00%
10	1940	1.94%	1,052.84	52.84	22.60	7.54%	-17.15%	-24.69%	-19.09%
11	1941	2.04%	983.64	-16.36	19.40	0.30%	-31.57%	-31.87%	-33.61%
12	1942	2.46%	933.97	-66.03	20.40	-4.56%	15.39%	19.95%	12.93%
13	1943	2.48%	996.86	-3.14	24.60	2.15%	46.07%	43.92%	43.59%
14	1944	2.46%	1,003.14	3.14	24.80	2.79%	18.03%	15.24%	15.57%
15	1945	1.99%	1,077.23	77.23	24.60	10.18%	53.33%	43.15%	51.34%
16	1946	2.12%	978.90	-21.10	19.90	-0.12%	1.26%	1.38%	-0.86%
17	1947	2.43%	951.13	-48.87	21.20	-2.77%	-13.16%	-10.39%	-15.59%
18	1948	2.37%	1,009.51	9.51	24.30	3.38%	4.01%	0.63%	1.64%
19	1949	2.09%	1,045.58	45.58	23.70	6.93%	31.39%	24.46%	29.30%
20	1950	2.24%	975.93	-24.07	20.90	-0.32%	3.25%	3.57%	1.01%
21	1951	2.69%	930.75	-69.25	22.40	-4.69%	18.63%	23.32%	15.94%
22	1952	2.79%	984.75	-15.25	26.90	1.17%	19.25%	18.08%	16.46%
23	1953	2.74%	1,007.66	7.66	27.90	3.56%	7.85%	4.29%	5.11%
24	1954	2.72%	1,003.07	3.07	27.40	3.05%	24.72%	21.67%	22.00%
25	1955	2.95%	965.44	-34.56	27.20	-0.74%	11.26%	12.00%	8.31%
26	1956	3.45%	928.19	-71.81	29.50	-4.23%	5.06%	9.29%	1.61%
27	1957	3.23%	1,032.23	32.23	34.50	6.67%	6.36%	-0.31%	3.13%
28	1958	3.82%	918.01	-81.99	32.30	-4.97%	40.70%	45.67%	36.88%
29	1959	4.47%	914.65	-85.35	38.20	-4.71%	7.49%	12.20%	3.02%
30	1960	3.80%	1,093.27	93.27	44.70	13.80%	20.26%	6.46%	16.46%
31	1961	4.15%	952.75	-47.25	38.00	-0.92%	29.33%	30.25%	25.18%
32	1962	3.95%	1,027.48	27.48	41.50	6.90%	-2.44%	-9.34%	-6.39%
33	1963	4.17%	970.35	-29.65	39.50	0.99%	12.36%	11.37%	8.19%

34	1964	4.23%	991.96	-8.04	41.70	3.37%	15.91%	12.54%	11.68%
35	1965	4.50%	964.64	-35.36	42.30	0.69%	4.67%	3.98%	0.17%
36	1966	4.55%	993.48	-6.52	45.00	3.85%	-4.48%	-8.33%	-9.03%
37	1967	5.56%	879.01	-120.99	45.50	-7.55%	-0.63%	6.92%	-6.19%
38	1968	5.98%	951.38	-48.62	55.60	0.70%	10.32%	9.62%	4.34%
39	1969	6.87%	904.00	-96.00	59.80	-3.62%	-15.42%	-11.80%	-22.29%
40	1970	6.48%	1,043.38	43.38	68.70	11.21%	16.56%	5.35%	10.08%
41	1971	5.97%	1,059.09	59.09	64.80	12.39%	2.41%	-9.98%	-3.56%
42	1972	5.99%	997.69	-2.31	59.70	5.74%	8.15%	2.41%	2.16%
43	1973	7.26%	867.09	-132.91	59.90	-7.30%	-18.07%	-10.77%	-25.33%
44	1974	7.60%	965.33	-34.67	72.60	3.79%	-21.55%	-25.34%	-29.15%
45	1975	8.05%	955.63	-44.37	76.00	3.16%	44.49%	41.33%	36.44%
46	1976	7.21%	1,088.25	88.25	80.50	16.87%	31.81%	14.94%	24.60%
47	1977	8.03%	919.03	-80.97	72.10	-0.89%	8.64%	9.53%	0.61%
48	1978	8.98%	912.47	-87.53	80.30	-0.72%	-3.71%	-2.99%	-12.69%
49	1979	10.12%	902.99	-97.01	89.80	-0.72%	13.58%	14.30%	3.46%
50	1980	11.99%	859.23	-140.77	101.20	-3.96%	15.08%	19.04%	3.09%
51	1981	13.34%	906.45	-93.55	119.90	2.63%	11.74%	9.11%	-1.60%
52	1982	10.95%	1,192.38	192.38	133.40	32.58%	26.52%	-6.06%	15.57%
53	1983	11.97%	923.12	-76.88	109.50	3.26%	20.01%	16.75%	8.04%
54	1984	11.70%	1,020.70	20.70	119.70	14.04%	26.04%	12.00%	14.34%
55	1985	9.56%	1,189.27	189.27	117.00	30.63%	33.05%	2.42%	23.49%
56	1986	7.89%	1,166.63	166.63	95.60	26.22%	28.53%	2.31%	20.64%
57	1987	9.20%	881.17	-118.83	78.90	-3.99%	-2.92%	1.07%	-12.12%
58	1988	9.18%	1,001.82	1.82	92.00	9.38%	18.27%	8.89%	9.09%
59	1989	8.16%	1,099.75	99.75	91.80	19.16%	47.80%	28.64%	39.64%
60	1990	8.44%	973.17	-26.83	81.60	5.48%	-2.57%	-8.05%	-11.01%
61	1991	7.30%	1,118.94	118.94	84.40	20.33%	14.61%	-5.72%	7.31%
62	1992	7.26%	1,004.19	4.19	73.00	7.72%	8.10%	0.38%	0.84%
63	1993	6.54%	1,079.70	79.70	72.60	15.23%	14.41%	-0.82%	7.87%
64	1994	7.99%	856.40	-143.60	65.40	-7.82%	-7.94%	-0.12%	-15.93%
65	1995	6.03%	1,225.98	225.98	79.90	30.59%	42.15%	11.56%	36.12%
66	1996	6.73%	923.67	-76.33	60.30	-1.60%	3.14%	4.74%	-3.59%
67	1997	6.02%	1,081.92	81.92	67.30	14.92%	24.69%	9.77%	18.67%
68	1998	5.42%	1,072.71	72.71	60.20	13.29%	14.82%	1.53%	9.40%
69	1999	6.82%	848.41	-151.59	54.20	-9.74%	-8.85%	0.89%	-15.67%
70	2000	5.58%	1,148.30	148.30	68.20	21.65%	59.70%	38.05%	54.12%
71	2001	5.75%	979.95	-20.05	55.80	3.57%	-30.41%	-33.98%	-36.16%
72	2002	4.84%	1,115.77	115.77	57.50	17.33%	-30.04%	-47.37%	-34.88%
73	2003	5.11%	966.42	-33.58	48.40	1.48%	26.11%	24.63%	21.00%
74	2004	4.84%	1,034.35	34.35	51.10	8.54%	24.22%	15.68%	19.38%
75	2005	4.61%	1,029.84	29.84	48.40	7.82%	16.79%	8.97%	12.18%
76	2006	4.91%	962.06	-37.94	46.10	0.82%	20.95%	20.13%	16.04%
77	2007	4.50%	1,053.70	53.70	49.10	10.28%	19.36%	9.08%	14.86%

78

79

Mean

6.1%

6.3%

Source: Bloomberg Web site: Standard & Poors Utility Stock Index % Annual Change, Dec. to Dec.

Dec. Bond yields from Ibbotson Associates 2008 Valuation Yearbook Table B-9 Long-Term Government Bonds Yields

Exhibit RAM-3 Utility Industry Historical Risk Premium

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
		Utility A-Rated Bond Yield	20 year Maturity Bond Value			Bond Total Return	S&P Utility Index Return	Utility Equity Risk Premium Over Bond Returns	Utility Equity Risk Premium Over Bond Yields
Line No.	Year	Yield	Value	Gain/Loss	Interest	Return	Return		
1	1931	5.12%	1,000.00						
2	1932	6.46%	850.73	-149.27	51.20	-9.81%	-0.54%	9.27%	-7.00%
3	1933	6.32%	1,015.77	15.77	64.60	8.04%	-21.87%	-29.91%	-28.19%
4	1934	5.50%	1,098.72	98.72	63.20	16.19%	-20.41%	-36.60%	-25.91%
5	1935	4.61%	1,115.47	115.47	55.00	17.05%	76.63%	59.58%	72.02%
6	1936	4.08%	1,071.99	71.99	46.10	11.81%	20.69%	8.88%	16.61%
7	1937	3.98%	1,013.70	13.70	40.80	5.45%	-37.04%	-42.49%	-41.02%
8	1938	3.90%	1,011.04	11.04	39.80	5.08%	22.45%	17.37%	18.55%
9	1939	3.52%	1,054.23	54.23	39.00	9.32%	11.26%	1.94%	7.74%
10	1940	3.24%	1,040.98	40.98	35.20	7.62%	-17.15%	-24.77%	-20.39%
11	1941	3.07%	1,025.27	25.27	32.40	5.77%	-31.57%	-37.34%	-34.64%
12	1942	3.09%	997.03	-2.97	30.70	2.77%	15.39%	12.62%	12.30%
13	1943	2.99%	1,014.97	14.97	30.90	4.59%	46.07%	41.48%	43.08%
14	1944	2.97%	1,003.00	3.00	29.90	3.29%	18.03%	14.74%	15.06%
15	1945	2.87%	1,015.14	15.14	29.70	4.48%	53.33%	48.85%	50.46%
16	1946	2.71%	1,024.58	24.58	28.70	5.33%	1.26%	-4.07%	-1.45%
17	1947	2.78%	989.32	-10.68	27.10	1.64%	-13.16%	-14.80%	-15.94%
18	1948	3.02%	964.17	-35.83	27.80	-0.80%	4.01%	4.81%	0.99%
19	1949	2.90%	1,018.11	18.11	30.20	4.83%	31.39%	26.56%	28.49%
20	1950	2.79%	1,016.77	16.77	29.00	4.58%	3.25%	-1.33%	0.46%
21	1951	3.11%	952.61	-47.39	27.90	-1.95%	18.63%	20.58%	15.52%
22	1952	3.24%	980.97	-19.03	31.10	1.21%	19.25%	18.04%	16.01%
23	1953	3.49%	964.23	-35.77	32.40	-0.34%	7.85%	8.19%	4.36%
24	1954	3.16%	1,048.65	48.65	34.90	8.35%	24.72%	16.37%	21.56%
25	1955	3.22%	991.20	-8.80	31.60	2.28%	11.26%	8.98%	8.04%
26	1956	3.56%	951.65	-48.35	32.20	-1.62%	5.06%	6.68%	1.50%
27	1957	4.24%	908.92	-91.08	35.60	-5.55%	6.36%	11.91%	2.12%
28	1958	4.20%	1,005.38	5.38	42.40	4.78%	40.70%	35.92%	36.50%
29	1959	4.78%	925.83	-74.17	42.00	-3.22%	7.49%	10.71%	2.71%
30	1960	4.78%	1,000.00	0.00	47.80	4.78%	20.26%	15.48%	15.48%
31	1961	4.62%	1,020.74	20.74	47.80	6.85%	29.33%	22.48%	24.71%
32	1962	4.54%	1,010.44	10.44	46.20	5.66%	-2.44%	-8.10%	-6.98%
33	1963	4.39%	1,019.83	19.83	45.40	6.52%	12.36%	5.84%	7.97%

34	1964	4.52%	983.00	-17.00	43.90	2.69%	15.91%	13.22%	11.39%
35	1965	4.58%	992.20	-7.80	45.20	3.74%	4.67%	0.93%	0.09%
36	1966	5.39%	901.59	-98.41	45.80	-5.26%	-4.48%	0.78%	-9.87%
37	1967	5.87%	943.94	-56.06	53.90	-0.22%	-0.63%	-0.41%	-6.50%
38	1968	6.51%	928.99	-71.01	58.70	-1.23%	10.32%	11.55%	3.81%
39	1969	7.54%	894.48	-105.52	65.10	-4.04%	-15.42%	-11.38%	-22.96%
40	1970	8.69%	891.81	-108.19	75.40	-3.28%	16.56%	19.84%	7.87%
41	1971	8.16%	1,051.83	51.83	86.90	13.87%	2.41%	-11.46%	-5.75%
42	1972	7.72%	1,044.47	44.47	81.60	12.61%	8.15%	-4.46%	0.43%
43	1973	7.84%	987.98	-12.02	77.20	6.52%	-18.07%	-24.59%	-25.91%
44	1974	9.50%	852.57	-147.43	78.40	-6.90%	-21.55%	-14.65%	-31.05%
45	1975	10.09%	949.69	-50.31	95.00	4.47%	44.49%	40.02%	34.40%
46	1976	9.29%	1,072.11	72.11	100.90	17.30%	31.81%	14.51%	22.52%
47	1977	8.61%	1,064.35	64.35	92.90	15.72%	8.64%	-7.08%	0.03%
48	1978	9.29%	938.71	-61.29	86.10	2.48%	-3.71%	-6.19%	-13.00%
49	1979	10.49%	900.41	-99.59	92.90	-0.67%	13.58%	14.25%	3.09%
50	1980	13.34%	802.50	-197.50	104.90	-9.26%	15.08%	24.34%	1.74%
51	1981	15.95%	843.97	-156.03	133.40	-2.26%	11.74%	14.00%	-4.21%
52	1982	15.86%	1,005.41	5.41	159.50	16.49%	26.52%	10.03%	10.66%
53	1983	13.66%	1,149.59	149.59	158.60	30.82%	20.01%	-10.81%	6.35%
54	1984	14.03%	975.38	-24.62	136.60	11.20%	26.04%	14.84%	12.01%
55	1985	12.47%	1,113.97	113.97	140.30	25.43%	33.05%	7.62%	20.58%
56	1986	9.58%	1,255.25	255.25	124.70	37.99%	28.53%	-9.46%	18.95%
57	1987	10.10%	955.69	-44.31	95.80	5.15%	-2.92%	-8.07%	-13.02%
58	1988	10.49%	967.63	-32.37	101.00	6.86%	18.27%	11.41%	7.78%
59	1989	9.77%	1,062.76	62.76	104.90	16.77%	47.80%	31.03%	38.03%
60	1990	9.86%	992.20	-7.80	97.70	8.99%	-2.57%	-11.56%	-12.43%
61	1991	9.36%	1,044.85	44.85	98.60	14.34%	14.61%	0.27%	5.25%
62	1992	8.69%	1,063.03	63.03	93.60	15.66%	8.10%	-7.56%	-0.59%
63	1993	7.59%	1,112.26	112.26	86.90	19.92%	14.41%	-5.51%	6.82%
64	1994	8.31%	930.36	-69.64	75.90	0.63%	-7.94%	-8.57%	-16.25%
65	1995	7.89%	1,041.91	41.91	83.10	12.50%	42.15%	29.65%	34.26%
66	1996	7.75%	1,014.12	14.12	78.90	9.30%	3.14%	-6.16%	-4.61%
67	1997	7.60%	1,015.30	15.30	77.50	9.28%	24.69%	15.41%	17.09%
68	1998	7.04%	1,059.61	59.61	76.00	13.56%	14.82%	1.26%	7.78%
69	1999	7.62%	940.94	-59.06	70.40	1.13%	-8.85%	-9.98%	-16.47%
70	2000	8.24%	939.72	-60.28	76.20	1.59%	59.70%	58.11%	51.46%
71	2001	7.78%	1,046.28	46.28	82.40	12.87%	-30.41%	-43.28%	-38.19%
72	2002	7.37%	1,042.55	42.55	77.80	12.03%	-30.04%	-42.07%	-37.41%
73	2003	6.58%	1,087.17	87.17	73.70	16.09%	26.11%	10.02%	19.53%
74	2004	6.16%	1,047.92	47.92	65.80	11.37%	24.22%	12.85%	18.06%
75	2005	5.65%	1,060.65	60.65	61.60	12.22%	16.79%	4.57%	11.14%
76	2006	6.07%	951.73	-48.27	56.50	0.82%	20.95%	20.13%	14.88%
77	2007	6.07%	1,000.00	0.00	60.70	6.07%	19.36%	13.29%	13.29%

78

79

Mean

5.0%

5.0%

Source: Bloomberg Web site: Standard & Poors Utility Stock Index % Annual Change, Dec. to Dec.
Bond yields from Bloomberg

DCF ANALYSIS: ANALYSTS' GROWTH FORECASTS**DCF Analysis**

Company	% Current Divid Yield (1)	Analysts' Growth Forecast (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1 AGL Resources	5.25	4.75	5.50	10.25	10.54
2 Atmos Energy	4.85	5.43	5.11	10.54	10.81
3 Laclede Group	3.04	10.00	3.34	13.34	13.52
4 Nicor Inc.	3.77	6.50	4.02	10.52	10.73
5 Northwest Nat. Gas	3.04	6.50	3.24	9.74	9.91
6 Piedmont Natural Gas	3.23	5.60	3.41	9.01	9.19
7 South Jersey Inds.	3.07	7.75	3.31	11.06	11.23
8 Southwest Gas	2.97	8.00	3.21	11.21	11.38
9 WGL Holdings Inc.	4.26	7.50	4.58	12.08	12.32
AVERAGE	3.72	6.89	3.97	10.86	11.07

Notes:

Column 1: Value Line Investment Analyzer Oct 2008

Column 2: Zacks long-term earnings growth forecast, 10/2008

Column 3 = Column 1 times (1 + Column 2/100)

NATURAL GAS UTILITIES
DCF ANALYSIS: VALUE LINE GROWTH FORECASTS

Company	% Current Divid Yield (1)	Value Line Proj Growth (2)	Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1 AGL Resources	5.25	3.00	5.41	8.41	8.69
2 Atmos Energy	4.85	4.50	5.07	9.57	9.84
3 Laclede Group	3.04	4.50	3.18	7.68	7.84
4 Nicor Inc.	3.77	5.00	3.96	8.96	9.17
5 Northwest Nat. Gas	3.04	5.50	3.21	8.71	8.88
6 Piedmont Natural Gas	3.23	6.50	3.44	9.94	10.12
7 South Jersey Inds.	3.07	6.00	3.25	9.25	9.43
8 Southwest Gas	2.97	7.50	3.19	10.69	10.86
9 WGL Holdings Inc.	4.26	3.50	4.41	7.91	8.14
AVERAGE	3.72	5.11	3.90	9.01	9.22

Notes:

Column 1, 2: Value Line Investment Analyzer, 10/2008

Column 3 = Column 1 times (1 + Column 2/100)

Column 4 = Column 2 + Column 3

COMBINATION GAS & ELEC 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 Alliant Energy	4.42	6.00	4.69	10.69	10.93
2 Ameren Corp.	6.35	2.50	6.51	9.01	9.35
3 Avista Corp.	3.26	9.00	3.55	12.55	12.74
4 CMS Energy Corp.	3.76	11.00	4.17	15.17	15.39
5 Consol. Edison	5.36	1.00	5.41	6.41	6.70
6 DTE Energy	5.15	5.00	5.41	10.41	10.69
7 Duke Energy					
8 Empire Dist. Elec.	5.75	10.00	6.33	16.33	16.66
9 Entergy Corp.	3.60	10.00	3.96	13.96	14.17
10 Exelon Corp.	3.01	9.00	3.28	12.28	12.45
11 MGE Energy	4.11	5.50	4.34	9.84	10.06
12 Northeast Utilities	3.31	11.50	3.69	15.19	15.38
13 NSTAR	4.29	7.50	4.61	12.11	12.35
14 Pepco Holdings	4.58	13.00	5.18	18.18	18.45
15 PG&E Corp.	4.12	5.00	4.33	9.33	9.55
16 PNM Resources	4.35	-0.50	4.33	3.83	4.06
17 PPL Corp.	3.73	14.00	4.25	18.25	18.48
18 Public Serv. Enterprise	3.84	10.00	4.22	14.22	14.45
19 Puget Energy Inc.	4.01	5.00	4.21	9.21	9.43
20 Sierra Pacific Res.	4.44	8.50	4.82	13.32	13.57
21 TECO Energy	4.78	7.50	5.14	12.64	12.91
22 UniSource Energy	3.23	2.00	3.29	5.29	5.47
23 Wisconsin Energy	2.56	8.00	2.76	10.76	10.91
24 Xcel Energy Inc.	4.62	7.50	4.97	12.47	12.73
AVERAGE	4.20	7.30	4.50	11.80	12.04

Notes:

Column 1, 2: Value Line Investment Analyzer, 10/2008

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 projection available for Duke Energy

COMBINATION GAS & ELECTRIC UTILITIES
DCF ANALYSIS: ANALYSTS' GROWTH FORECASTS

Exhibit __ (RAM-7)

Company		% Current Divid Yield	Proj EPS Growth	% Expected Divid Yield	Cost of Equity	ROE
		(1)	(2)	(3)	(4)	(5)
1	Alliant Energy	4.42	7.00	4.73	11.73	11.98
2	Ameren Corp.	6.35	5.00	6.67	11.67	12.02
3	Avista Corp.	3.26	5.00	3.42	8.42	8.60
4	CMS Energy Corp.	3.76	9.40	4.11	13.51	13.73
5	Consol. Edison	5.36	2.75	5.51	8.26	8.55
6	DTE Energy	5.15	6.33	5.48	11.81	12.09
7	Duke Energy	5.17	5.83	5.47	11.30	11.59
9	Entergy Corp.	3.60	11.50	4.01	15.51	15.73
10	Exelon Corp.	3.01	8.50	3.27	11.77	11.94
12	Northeast Utilities	3.31	10.00	3.64	13.64	13.83
13	NSTAR	4.29	6.40	4.56	10.96	11.20
14	Pepeco Holdings	4.58	9.60	5.02	14.62	14.88
15	PG&E Corp.	4.12	7.67	4.44	12.11	12.34
16	PNM Resources	4.35	6.20	4.62	10.82	11.06
17	PPL Corp.	3.73	16.25	4.34	20.59	20.81
18	Public Serv. Enterprise	3.84	12.00	4.30	16.30	16.53
19	Puget Energy Inc.	4.01	6.00	4.25	10.25	10.47
20	Sierra Pacific Res.	4.44	15.00	5.11	20.11	20.37
21	TECO Energy	4.78	9.75	5.25	15.00	15.27
23	Wisconsin Energy	2.56	9.60	2.81	12.41	12.55
24	Xcel Energy Inc.	4.62	5.60	4.88	10.48	10.74
AVERAGE		4.22	8.35	4.57	12.92	13.16
MEDIAN		4.29	7.67	4.56	11.81	12.09

Notes:

Column 1: Value Line Investment Analyzer, 10/2008

Column 2: Zacks long-term earnings growth forecast, 10/2008

Column 3 = Column 1 times (1 + Column 2/100)

Column 4 = Column 3 + Column 2

Column 5 = (Column 3 / 0.95) + Column 2

RESUME OF ROGER A. MORIN

(Fall 2008)

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DATE OF BIRTH: 3/5/1945

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Robinson College of Business
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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
Havasu 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
Allele (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.

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
PAUL A. OLMSTED

1 Q. Please state your name and business address.

2 A. My name is Paul A. Olmsted and my business address is 4
3 Irving Place, New York, New York 10003.

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

5 A. I am Director, Energy Management Gas Supply of
6 Consolidated Edison Company of New York, Inc. ("Con
7 Edison").

8 Q. Please state your educational background.

9 A. I graduated from the University of California at
10 Berkeley in 1980 with a Bachelor of Arts degree in
11 History and received a Master's in Business
12 Administration from New York University in 1996.

13 Q. Please describe your work experience.

14 A. Between 1981 and 1989, I was a Senior Economist with
15 Petroleum Research Associates, an energy consulting
16 firm in New York City. I joined the Gas Supply
17 Department of Con Edison in 1989 as a Senior Analyst.
18 I became Manager of Planning and Economic Analysis in
19 1992. In 1996, I became Director of Gas Supply; in
20 1999, General Manager of Technical Operations in Gas
21 Engineering; and, in October 2003, Director of
22 Purchasing. I assumed my current responsibilities as
23 Director of Gas Supply in April 2006.

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
PAUL A. OLMSTED

1 Q. Please generally describe your current
2 responsibilities.

3 A. I am responsible for the following areas in the Gas
4 Supply Department: (i) gas purchasing and scheduling;
5 (ii) gas billing and analysis and contract
6 administration; (iii) gas hedging and market analysis;
7 (iv) gas transportation services; (v) and long- and
8 short-term planning. As Director of Gas Supply, I
9 oversee these areas for both Con Edison and Orange and
10 Rockland Utilities, Inc. ("O&R" or "Orange and
11 Rockland") (jointly referred to as "the Companies"),
12 except that O&R is responsible for its own gas
13 transportation services.

14 Q. Do you belong to any professional organizations?

15 A. Yes, I am a member of the Society of Gas Operators.

16 Q. Have you previously testified before the New York State
17 Public Service Commission ("Commission")?

18 A. Yes, I submitted testimony in Case 93-G-0096 and Case
19 06-G-1332.

20 Q. Please summarize the areas covered in your testimony.

21 A. I will discuss the Companies' gas purchasing and
22 hedging programs and explain how the Companies strive
23 to provide a reasonably-priced gas supply for their

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
PAUL A. OLMSTED

1 customers that reflects the Companies' efforts to (i)
2 maintain a reliable gas supply, (ii) minimize gas costs
3 to their firm customers, and (iii) reduce gas price
4 volatility, consistent with Commission policy for gas
5 utilities. I will also address: (i) the measures that
6 the Companies undertake to maintain system reliability;
7 (ii) the Companies' gas supplier and transportation
8 contract procurement process; (iii) the Companies'
9 long-term planning process; (iv) the Companies'
10 Marginal Supply Cost Study; and (v) gas working capital
11 storage cost allocation.

12 Q. I show you Exhibit __ (G-9), Schedules 1 through 14,
13 and ask if this was prepared under your direction and
14 supervision?

15 A. Yes, it was.

16 GAS SUPPLY PROGRAM

17 Q. Please describe the nature of the Companies' gas supply
18 portfolio.

19 A. Con Edison and O&R have implemented a combined
20 portfolio that allows for the joint utilization of
21 their gas supply and pipeline contracts. The combined
22 portfolio is operated for the benefit of the firm gas
23 customers of both Con Edison, including its steam

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
PAUL A. OLMSTED

1 customers, and O&R. The structure of the Companies'
2 combined portfolio is illustrated on Schedules 1, 2, 3,
3 and 4 of Exhibit __ (G-9).

4 Q. Please describe the objective of the Companies' gas
5 purchasing and hedging programs.

6 A. The Companies' objective is to obtain a reasonably-
7 priced gas supply that reflects their efforts to (i)
8 maintain a reliable gas supply, (ii) minimize gas costs
9 for their firm customers, and (iii) reduce gas price
10 volatility. The objective also includes maintaining a
11 diverse gas supply and capacity portfolio, thus giving
12 the Companies the flexibility to react to changing
13 weather conditions and the ability to meet design
14 winter requirements of firm gas customers.

15 Q. How do the Companies seek to maintain reliability of
16 supply?

17 A. One of the cornerstones of a reliable gas supply
18 portfolio is its diversity. The Companies' combined
19 gas supply and capacity portfolio includes a diverse
20 supply of both domestic and Canadian gas production, as
21 set forth on Exhibit __ (G-9), Schedule 1, Gas Supply
22 Contracts. The Companies also have firm pipeline
23 capacity contracts with nine different interstate

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
PAUL A. OLMSTED

1 transportation companies, as set forth on Exhibit __
2 (G-9), Schedule 2, Pipeline Transportation Contracts,
3 which provides for diversity of delivery. In addition,
4 the Companies have a number of contracts for
5 underground storage. These storage contracts are
6 listed on Exhibit __ (G-9), Schedule 3, Storage
7 Contracts. Within its distribution territory, Con
8 Edison owns and operates a liquefied natural gas
9 ("LNG") "peak shaving" facility, which is both a source
10 of peak day supply on the extreme coldest winter days
11 and contingency protection. Within its gas
12 distribution territory (i.e., Middletown, New York),
13 O&R owns and operates a propane facility, which
14 similarly provides peak day capability and contingency
15 protection, serving as an in-city source of supply
16 protecting against an interstate pipeline or utility
17 distribution system disruption. As discussed in the
18 testimony of Company witness DiLoreto, the Company's
19 Middletown propane facility will be decommissioned and
20 retired in the spring of 2009 following completion of
21 the new Millennium gas transmission pipeline (currently
22 scheduled for December 2008). These peaking facilities
23 are set forth on Exhibit__ (G-9), Schedule 4).

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
PAUL A. OLMSTED

1 Q. What are design weather conditions?

2 A. The peak day represents the quantity of gas that O&R's
3 firm customers would require in a twenty-four hour
4 period at an average daily temperature of zero degrees
5 Fahrenheit. Exhibit __ (G-9), Schedule 5, Combined Con
6 Edison/O&R Peak Day Forecasted Requirements, provides a
7 forecast of the Companies' firm customers' peak day
8 demand at an average daily temperature of zero degrees
9 Fahrenheit for each winter period (i.e., November
10 through March) beginning with the winter of 2008/2009
11 through winter 2010/2011. Gas Supply also calculates
12 the gas requirements for meeting demand over the course
13 of a winter under severe weather conditions (a "design
14 winter") to assure that storage and peaking supplies
15 are adequate.

16 Q. Please explain how the Companies' contracts enable them
17 to meet these design weather conditions.

18 A. Peak day demand is met through the delivery of firm
19 supply via the Companies' firm pipeline transportation
20 capacity, withdrawals from firm market area storage
21 capacity, delivery of firm peaking supplies to the
22 Companies' city gates, and gas vaporized at the LNG and
23 propane plants. Exhibit __ (G-9), Schedules 2, 3, and

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
PAUL A. OLMSTED

1 4 demonstrate how the Companies plan to meet design
2 winter conditions.

3 Q. Why is underground market area storage an important
4 component of the Companies' gas supply portfolio?

5 A. Underground market area storage serves three purposes
6 for local distribution companies.

7 First, the proximity of market area storage to the
8 service territory avoids the higher costs of
9 contracting for long-haul pipeline transportation
10 capacity to meet load on only the coldest days and
11 increases utilization of existing long-haul pipeline
12 transportation capacity during the summer storage
13 injection season to fill market area storage fields.

14 Second, market area storage provides flexibility
15 for gas deliveries that helps keep the Companies'
16 system supply in balance with both full service and
17 retail choice customer demand. That is, market area
18 storage is an integral part of the Companies' ability
19 to provide essential load-following services, which in
20 turn provides the Companies with flexibility to react
21 to lower customer demand during warmer-than-normal
22 periods and higher demand during colder-than-normal
23 periods. In addition, the ability to divert city gate

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
PAUL A. OLMSTED

1 deliveries into storage or to move gas out of storage
2 to the city gate within a gas day enables the Companies
3 to balance their system deliveries with customer usage
4 and gas marketers' deliveries.

5 Third, market area storage allows the Companies to
6 take advantage of seasonal price opportunities. Gas
7 prices in the summer have been lower on average than
8 during winter months. The process of filling storage
9 to the Companies' targeted levels during the summer and
10 withdrawing this gas during the winter assists in
11 reducing price volatility to firm gas customers.

12 Q. Why is production area storage a component of the
13 Companies' portfolio?

14 A. Production area storage provides the following
15 benefits:

16 (1) Production area storage offers protection from
17 wellhead freeze-offs and delivery disruptions
18 during hurricane- related events. Exhibit __ (G-
19 9), Schedule 6, Production Area Storage, lists the
20 number of days and the total gas volume that the
21 Companies withdrew from storage, during recent
22 hurricanes.

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
PAUL A. OLMSTED

1 (2) Depending on market conditions, production area
2 storage can act as a supply source displacing
3 higher cost gas purchases that would otherwise be
4 made to satisfy the needs of full service
5 customers.

6 (3) Production area storage also provides flexibility
7 to balance the intra-day changes in system loads
8 by allowing deliveries in and out of the fields as
9 required. As the Companies' retail choice
10 programs have grown, this benefit has increased in
11 importance.

12 Q. Please describe the initiatives the Companies have
13 taken in the wholesale market to minimize gas costs.

14 A. The Companies strive to minimize gas costs by using
15 competitive bidding processes and requests for
16 proposals to the marketplace, and by taking advantage
17 of opportunities that arise through the Companies'
18 participation in the Northeast Gas Markets group. The
19 Companies also seek to optimize their combined
20 portfolio primarily through capacity releases, as well
21 as off-system bundled sales.

22 Q. Please provide an illustration of the benefits from the
23 Companies' portfolio optimization efforts.

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
PAUL A. OLMSTED

1 A. Exhibit __ (G-9), Schedule 7, Non-Traditional Revenues,
2 illustrates annual benefits received from the
3 Companies' portfolio optimization efforts to minimize
4 overall costs to their firm gas customers.

5 PRICE VOLATILITY REDUCTION

6 Q. What efforts have the Companies undertaken to reduce
7 the volatility of gas prices to their firm gas
8 customers?

9 A. Through active management of the combined gas supply
10 and transportation portfolio, the Companies seek to
11 reduce the volatility of gas prices delivered to their
12 firm gas customers. Specifically, the Companies take
13 advantage of: (1) pricing mechanisms in their gas
14 supply contracts, (2) storage utilization, (3) firm
15 transportation agreements on numerous interstate
16 pipelines, and (4) a gas hedging program.

17 Q. Please explain.

18 A. The Companies' gas supply contracts generally provide
19 the option to trigger a NYMEX price, use first-of-the
20 month index prices, or negotiate a monthly commodity
21 price months before commencement of the delivery
22 period. If the future commodity price is agreed upon
23 in advance, then the cost of gas for these quantities

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
PAUL A. OLMSTED

1 is no longer subject to market volatility. As I
2 previously described, storage also plays a significant
3 role in reducing the volatility of total gas costs.
4 Gas is injected into storage during the summer months,
5 when the price of gas has traditionally been lower than
6 in the winter months, and stored for use by firm
7 customers during colder winter days.

8 Long-haul firm transportation agreements, in
9 addition to satisfying the need for reliability of gas
10 deliveries, enables the Companies to avoid the
11 volatility of basis (i.e., the value of transporting
12 gas from a supply point to a delivery point), which
13 would be the case if the Companies were to buy
14 transportation capacity to the market area on an as-
15 needed basis.

16 Q. Please describe the Companies' gas hedging program.

17 A. The Companies' hedging program is designed to reduce
18 gas price volatility. One of the hedging program's
19 components is the Monthly Plan, which dictates the use
20 of physical price locks and/or various financial
21 instruments to hedge natural gas prices for part of the
22 gas supply necessary to meet the monthly requirements
23 of firm sales customers. The program provides for the

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
PAUL A. OLMSTED

1 Companies to hedge a minimum quantity of its forecasted
2 sales using physical and/or financial price hedges
3 throughout the year.

4 Q. How have the Companies managed credit issues?

5 A. Credit risk is managed by the oversight of two risk
6 committees. One is the Risk Oversight Committee
7 ("ROC"), comprised of senior officers of the Companies;
8 and the other is the Regulated Risk Management
9 Committee ("RRMC"), comprised of other officers of the
10 Companies. The ROC oversees corporate risk strategy
11 and establishes risk policies from an enterprise-wide
12 perspective, including credit risk. The ROC also
13 establishes credit risk tolerances, including the
14 amount of credit the Companies will extend to a
15 counterparty. The RRMC approves credit risk policies
16 and procedures and assures compliance with the policies
17 and procedures governing the wholesale energy
18 activities of the Companies. The RRMC approves the
19 appropriate risk measurement methodologies so that
20 exposures are consistent with the Companies' risk
21 policies and credit limits.

22 Furthermore, the Companies have a separate
23 department, Energy Risk Management Utilities ("ERM"),

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
PAUL A. OLMSTED

1 to oversee and manage credit risks associated with gas
2 and electric purchases. ERM establishes credit limits
3 for each counterparty with whom the Companies have
4 physical or financial exposure. It monitors and
5 reports to the RRMC and ROC on the counterparties'
6 credit limits and ratings and the Companies' exposure
7 to these counterparties.

8 SUPPLY AND CAPACITY PORTFOLIO CHANGES

9 Q. What changes in the Companies' supply portfolio do you
10 anticipate prior to and within the rate year?

11 A. As illustrated in Exhibit __ (G-9), Schedule 1, certain
12 of the Companies' gas supply contracts expire each
13 year. Existing domestic contracts may be renegotiated
14 or replaced through competitive bidding or requests for
15 proposals ("RFPs"); and Canadian supplies may be
16 added/replaced through Northeast Gas Markets, Inc.
17 ("NEGM"), which acts as the agent for a group of
18 utilities, including the Companies.

19 The gas supply contracts typically have one-,
20 three-, or five-year terms. Prior to contract
21 expiration, Gas Supply evaluates whether the supply is
22 required, which depends on, among other things, the
23 status of retail access in the Companies' service

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
PAUL A. OLMSTED

1 territories. Gas Supply is planning to replace through
2 an RFP or competitive bidding process the contracts
3 listed on Exhibit _ (G-9), Schedule 1, that expire in
4 2008/09.

5 Q. Do you anticipate any changes in the capacity
6 portfolio?

7 A. As transportation and storage contracts near the end of
8 their existing terms, Gas Supply evaluates and
9 determines the need for each contract. Assuming the
10 contract is required to meet firm gas customer load
11 and/or manage gas system operations, Gas Supply
12 conducts an assessment of the marketplace to determine
13 if alternative transportation and/or storage contracts
14 of at least equal reliability and flexibility can be
15 acquired more economically. If more desirable
16 replacement contracts cannot be supplied by the
17 marketplace, then these contracts will be renewed,
18 consistent with existing pipeline tariff right of first
19 refusal provisions or other applicable contract
20 provisions. In addition, effective for the winter
21 2008/2009, the Companies have contracted with the
22 Millennium pipeline for up to 180,000 Dth/day of
23 capacity, as well as with the Algonquin and Iroquois

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
PAUL A. OLMSTED

1 pipelines for up to 125,000 Dth/day and 100,000
2 Dth/day, respectively, of downstream delivery to the
3 Con Edison (should this refer to O&R, or perhaps the
4 Companies?) distribution system. Gas Supply has also
5 contracted with Central New York Oil and Gas ("CNYOG")
6 for 105,000 Dth/day of withdrawal and 4,200,000 Dth of
7 space in an expansion of CNYOG's Stagecoach Storage
8 field located in upstate New York. In addition,
9 effective April 1, 2008, the Companies have contracted
10 for up to 75,000 Dth/day of capacity on National Fuel
11 Gas Supply Corporation's pipeline, from Leidy, PA to
12 Independence, NY, the most upstream point on Millennium
13 Pipeline, and 598,000 Dth of storage space on the
14 National Fuel Gas pipeline system.

15 REGULATORY ACTIVITIES

16 Q. I show you a document entitled Exhibit __ (G-9),
17 Schedule 8, "FERC DOCKET INTERVENTIONS", and ask if
18 this was prepared under your direction and supervision?

19 A. Yes, it was.

20 Q. What other steps have the Companies taken to maintain
21 the reasonableness of their gas costs and the
22 reliability of their supply?

23 A. The Companies participate in myriad Federal Energy

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
PAUL A. OLMSTED

1 Regulatory Commission ("FERC") proceedings involving
2 (i) their pipeline and storage providers ("service
3 providers") and (ii) FERC generic issues that impact
4 the cost and quality of the gas service received by the
5 Companies from FERC-regulated entities. Exhibit __ (G-
6 9), Schedule 8, lists the FERC dockets in which the
7 Companies have intervened since November 2003. When
8 appropriate, the Companies also participate in FERC
9 dockets and other forums through their membership in
10 the American Gas Association ("AGA"). The Companies
11 closely follow FERC proceedings that impact rates and
12 terms of service of their pipeline service providers
13 and actively participate in litigation as well as
14 negotiations relating to (i) the rates that their
15 pipeline and storage service providers are permitted to
16 charge the Companies, such as the recently concluded
17 Transcontinental Gas Pipe Line rate case, and (ii)
18 pipeline cost allocation issues involving, for example,
19 fuel retention and electric power compression charges.
20 The Companies closely monitor proposed tariff changes
21 by service providers that modify their terms of
22 service, including matters related to rights of first
23 refusal, bidding rules, service provider credit

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
PAUL A. OLMSTED

1 policies and tariff and negotiated agreement filings
2 that could affect the quality of pipeline service to
3 the Companies. The Companies also closely monitor new
4 incremental services being offered by the Companies'
5 current service providers so that the rates of those
6 new incremental services are not subsidized by existing
7 customers, such as the Companies.

8 Q. What other steps have the Companies taken to maintain
9 the reliability of their supply?

10 A. The Companies have actively supported the adoption by
11 the natural gas industry of gas quality specifications
12 that will allow for increased supplies, particularly
13 from new LNG import terminals and so-called
14 unconventional gas supplies such as shale gas.

15 Q. Are the Companies a member of any groups addressing gas
16 reliability issues in New York State?

17 A. Yes. The Companies have been an active participant in
18 the Natural Gas Reliability Advisory Group ("NGRAG")
19 from its initiation. During the past year, the NGRAG
20 focused discussion on the FERC rule regarding Capacity
21 Release, specifically on how it would affect the
22 state's retail access programs. The revised FERC Rule,
23 among other things, exempts state retail access

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
PAUL A. OLMSTED

1 programs from the capacity bidding requirement and
2 allows capacity releases under the retail programs to
3 be at the utilities' ("LDCs") weighted average cost of
4 capacity ("WACOC") instead of at maximum pipeline
5 rates. The Companies anticipate working through the
6 NGRAG to determine when and if to file tariff changes
7 for the winter of 2009/2010.

8 Q. Are the Companies an active member of industry
9 organizations?

10 A. Yes. We are active in the AGA, Northeast Gas
11 Association, Gas Technology Institute, and in the
12 Wholesale Gas Quadrant of the North American Energy
13 Standards Board ("NAESB"). We are also active in the
14 AGA FERC Regulatory Committee, which is involved with a
15 range of federal regulatory issues relating to gas
16 supply.

17 Q. Please describe the Companies efforts in connection
18 with NAESB.

19 A. We have been a member of NAESB and its predecessor
20 organization, the Gas Industry Standards Board
21 ("GISB"), since the latter's inception in 1994. The
22 transformation of GISB to NAESB in 2001 was designed to
23 address changes in the energy industry. We have

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
PAUL A. OLMSTED

1 participated actively in NAESB's efforts (i) in
2 connection with establishing intra-day capacity recall
3 standards and (ii) in amending its Standard Gas
4 Purchase and Sales Contract and model Credit Support
5 Addendum. The updated Standard Gas Purchase and Sales
6 Contract was recently adopted by the industry and
7 includes changes suggested by Con Edison that allow
8 purchasers of natural gas additional time to change
9 payment information, thereby minimizing the possibility
10 of inaccurate or costly payment errors.

11 MARGINAL COST STUDY

12 Q. Please address Orange and Rockland's marginal cost
13 study with respect to gas supply costs.

14 A. Supply-side marginal costs are the costs of procuring
15 and transporting an additional unit of gas to the
16 Companies' distribution systems. Fixed costs that are
17 associated with existing resources are not considered
18 because they do not vary with additional usage and
19 because O&R cannot avoid paying them.

20 Q. Did you consider individual marginal cost components?

21 A. Yes, I considered marginal capacity costs and commodity
22 costs.

23 Q. Please define marginal capacity cost.

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
PAUL A. OLMSTED

1 A. Marginal capacity cost is the cost of adding reliable
2 gas deliverability, which may include pipeline
3 capacity, storage capacity, and/or firm gas supply at
4 the city gate, to satisfy additional firm customer
5 demand at design conditions.

6 Q. Please define marginal commodity cost.

7 A. Marginal commodity cost is the cost of an incremental
8 purchase of gas required to meet system demand that
9 exceeds committed supply sources and planned supply
10 additions. Through the use of an optimization model
11 and the forecasted system demand, the cost of the last
12 dekatherm dispatched to firm gas customers is the
13 marginal commodity cost of gas.

14 Q. What is the forecast period used in your marginal cost
15 study?

16 A. The forecast period for the marginal cost study is the
17 three-year period from November 2008 through October
18 2011.

19 Q. Please explain the development of the marginal capacity
20 cost.

21 A. Exhibit __ (G-9), Schedule 9, Combined Con Edison/O&R
22 Summer Season Supply/Demand Balance, Schedule 10,
23 Combined Con Edison/O&R Winter Season Supply/Demand

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
PAUL A. OLMSTED

1 Balance, and Schedule 11, Combined Con Edison/O&R Peak
2 Day Supply/Demand Balance compare the Companies' firm
3 transportation and supply capability to gas demand on a
4 summer season, normal winter season, and peak-day
5 basis. The firm transportation and supply capability
6 includes all firm transportation deliverability and
7 currently flowing firm supplies. These Schedules
8 demonstrate that the need to add capacity to serve firm
9 customer requirements is driven by the Companies'
10 requirement to provide for firm customer needs on a
11 design-day basis.

12 Q. Please explain the calculation of the marginal
13 commodity cost.

14 A. The marginal commodity cost is measured performing a
15 dispatch simulation analysis of the Companies'
16 supplies. The simulation uses the Companies' forecasts
17 of firm demand for design conditions. Exhibit __ (G-
18 9), Schedule 12, Combined Con Edison/O&R Natural Gas
19 Marginal Monthly Commodity Costs, displays the monthly
20 marginal commodity costs for the three years of the
21 study. Exhibit __ (G-9), Schedule 13, Combined Con
22 Edison/O&R Marginal Commodity/Capacity Costs,
23 summarizes these costs to show the impact on the

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
PAUL A. OLMSTED

1 average annual, summer season, and winter season
2 commodity cost of gas, the marginal commodity cost on a
3 peak day, and the marginal capacity costs.

4 STORAGE WORKING CAPITAL COST ALLOCATION

5 Q. What is O&R's proposal for the allocation of gas
6 storage working capital costs between full service and
7 firm transportation customers?

8 A. The Company is proposing that (i) the Gas in Storage
9 Working Capital charge be allocated between both the
10 Company's full service customers and all of its firm
11 customers and (ii) the volumetric rate in the (Merchant
12 Function Charge ("MFC") and the volumetric rate for the
13 (Monthly Gas Adjustment ("MGA") be equal in value. By
14 doing this allocation, full service customers would pay
15 two times the rate (once through the MFC Component and
16 once through the MGA Component) that firm
17 transportation customers would pay (through the MFC
18 Component only). This would allocate costs between
19 full service (sales and transportation) customers and
20 transportation only customers at a ratio of 2:1. At
21 the end of each Rate Year, the Gas in Storage Working
22 Capital included in the MFC and MGA would be trued-up
23 to actual costs and the difference included in the

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
PAUL A. OLMSTED

1 subsequent year's calculation.

2 Q. Could you please describe the components of the
3 allocation of gas costs?

4 A. The gas in storage can be broken down into the
5 following three components: baseload supply, system
6 balancing (load following), and system reliability.
7 The baseload supply is the gas used to meet customer
8 demand requirements under normal weather conditions.
9 Baseload supply gas withdrawn from storage is used to
10 satisfy O&R's sales customers' requirements; and
11 baseload gas withdrawn from storage under the Winter
12 Bundled Sales Program ("WBS") is used to satisfy O&R's
13 transportation customers' requirements. The system
14 balancing (load following) component is used to meet
15 demand requirements that occur above our normal weather
16 requirements. Both sales and transportation customers
17 utilize this component. The system reliability
18 component is the gas in storage to maintain operational
19 requirements and serves all customers. Gas Supply has
20 performed two analyses of the usage of gas storage in
21 these categories by both full service customers and
22 transportation customers.

23 Q. Please describe the two analyses and the results.

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
PAUL A. OLMSTED

1 A. The first analysis is a statistical analysis based on
2 load following; and the second analysis was based on
3 planned baseload storage withdrawals. The results of
4 these analyses are summarized in my Exhibit __ (G-9),
5 Schedule 14. The statistical analysis considered
6 historical daily load variations and determined the
7 amount of gas required for load following. Based on
8 the amount of gas maintained for system reliability,
9 the amount of gas utilized as baseload supply was
10 calculated. Using this approach, the ratio of full
11 service customers to all firm customers was calculated
12 to be 1.17:1 or 1.17 times the MGA component. This
13 top-down approach was used to determine if the
14 calculated baseload storage withdrawals were consistent
15 with our planned withdrawals. The second analysis
16 addressed planned baseload storage withdrawals and
17 considered how much gas is planned on being used as
18 baseload supply (including Winter Bundled Sales Service
19 ("WBS"), a service offered to retail choice providers).
20 As in the statistical analysis, after considering the
21 amount of gas that is maintained for system
22 reliability, the amount of gas utilized for load
23 following was calculated. The ratio of full service

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
PAUL A. OLMSTED

1 customers to all firm customers was then calculated to
2 be 1.32:1 or 1.32 times the MGA component. This
3 bottom-up approach was used to determine if the
4 calculated load following usage was consistent with the
5 statistical analysis results. The two approaches
6 yielded similar results. The methodology used to
7 determine the allocation is reasonable because the
8 majority of the components are utilized for all firm
9 gas customers.

10 Q. Why are you proposing to allocate costs on a 2:1 ratio
11 rather than the 1.17:1 or 1.32:1 ratios that resulted
12 from your analyses?

13 A. The analyses that we performed demonstrate that gas
14 storage – including all three components of it – is
15 used to meet the needs of all firm customers, not only
16 the full-service customers. Currently, O&R's full
17 service customers are being allocated gas storage
18 working capital costs at a 5:1 ratio and the analyses
19 demonstrate that this ratio now is too high. Until a
20 further analysis can be performed with additional data,
21 reducing the ratio to 2:1 (rather than below 2:1) would
22 yield a more equitable result and have the additional

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
PAUL A. OLMSTED

- 1 benefit of being the same ratio that was established
2 for the third year of Con Edison's last gas rate case.
3 Q. Does this conclude your testimony?
4 A. Yes, it does.

1

2 Q. Please state your name and business address.

3 A. My name is John Perkins and my business address is 4
4 Irving Place, New York, NY 10003.

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

6 A. I am Director, Corporate Finance for Consolidated
7 Edison Company of New York, Inc. ("Con Edison" or
8 "CECONY"). I am also Treasurer of Orange and Rockland
9 Utilities, Inc. ("Orange & Rockland", "O&R", or the
10 "Company").

11 Q. Briefly describe your educational background.

12 A. I graduated from MIT in 1972 and received B.S. degrees
13 in Economics and Civil Engineering. I received M.A.
14 and M.Phil. degrees in Economics from Yale University
15 in 1974 and 1975, respectively. I took several
16 additional graduate courses in Finance from New York
17 University.

18 Q. Please summarize your professional background.

19 A. I joined Con Edison in 1982. My previous positions
20 have been as Director, Financial Administration,
21 Director, Corporate Planning, Director, Financial

1 Services, and Manager, Financial Services. Prior to
2 joining Con Edison, I was employed by Chase
3 Econometrics/Interactive Data from 1980-1982 and by
4 the Graduate School of Business of Columbia University
5 (1976-1979), where I taught courses in economics and
6 transportation.

7 Q. Please describe your current responsibilities.

8 A. My responsibilities include preparing the cash
9 forecast and planning and executing financing for
10 Consolidated Edison, Inc. ("CEI"), and its
11 subsidiaries, including Orange & Rockland. In
12 addition, I manage the relationships with credit
13 rating agencies and undertake various financial
14 analyses.

15 Q. Have you previously sponsored testimony before
16 regulatory bodies?

17 A. Yes. I have sponsored testimony on capitalization and
18 cost of capital for Orange & Rockland in Case
19 07-E-0949, Case 06-E-1433 and Case 05-G-1494, in the
20 matter of the securitization of certain deferred
21 balances and testimony on capital structure and rates

1 of return for Rockland Electric Company ("RECO")(a New
2 Jersey public utility subsidiary of Orange & Rockland)
3 before the New Jersey Board of Public Utilities, and
4 have sponsored testimony on rates of return and capital
5 structure for Pike County Light & Power Company
6 ("Pike")(a Pennsylvania public utility subsidiary of
7 Orange & Rockland) before the Pennsylvania Public
8 Utility Commission.

9 I have also sponsored testimony concerning the impact
10 of rate recovery on ratings and thus on costs in the
11 latest Con Edison steam and gas cases.

12 Q. Please summarize your testimony.

13 A. My testimony discusses the historic and projected
14 capital structure of Orange & Rockland and the cost of
15 capital, the current credit ratings of Orange &
16 Rockland, the methodology used by the rating agencies
17 to determine these ratings, the comments that have
18 been made as to the strength of key financial ratios
19 of Orange & Rockland, and the potential impact of
20 reduced ratings. Throughout I will discuss the impact
21 of the current volatile financial markets on the

1 ability of Orange & Rockland to raise capital at a
2 reasonable cost.

3 CAPITALIZATION AND COST OF CAPITAL

4 Q. What capital structure do you recommend should be used
5 in this proceeding?

6 A. I recommend the use of the consolidated capitalization
7 of Orange & Rockland in this proceeding.

8 Q. Please describe the consolidated capitalization.

9 A. Consolidated capitalization refers to the consolidated
10 capital structure of Orange & Rockland and its wholly-
11 owned utility subsidiaries, RECO and Pike. The
12 consolidated capital structure is presented on Exhibit
13 G-8 and consists of the following Schedules:

14 1. Schedule 1 - Forecasted Consolidated Capitalization
15 and Cost Rates for the thirteen months ended October
16 31, 2010.

17 2. Schedule 2 - Long Term Debt

18 Q. Please describe any projected changes in long-term
19 debt between the end of the historic test year (June
20 30, 2008) and the end of the first rate year (the
21 thirteen months ended October 31, 2010) and how such

changes have been incorporated into your forecasted capitalization and cost data for the thirteen months ended October 31, 2010.

A. Changes in the forecasted balance of long-term debt during the period July 2008 through October 2010 are as follows: New debt issued during the period include \$50 million of Debentures, Series A 2008, 6.15% issued August 25, 2008, due September 1, 2018; \$100 million of Debentures, Series A 2009, 9.03% issued March 1, 2009, due March 1, 2019; \$75 million of Debentures, Series B 2009, 9.65%, issued September 1, 2009, due September 1, 2039; \$55 million of Debentures, Series A 2010, 9.38%, issued June 1, 2010, due June 1, 2020; and \$80 million of Debentures, Series B 2010, 9.90%, issued September 1, 2010, due September 1, 2040. We have projected a mix of 10-year and 30-year maturities because of the large size of the financing program and our concern with having significant maturities to deal with in the period 2019 to 2020 if we use only 10-year debt.

1 In addition, debt retirements during the period are
2 projected to be as follows: the total outstanding
3 balance of the Company's Pollution Control Debt is
4 expected to be redeemed during March 2009. The
5 estimated outstanding balances at that date are \$6.020
6 million of the 1994 PCBs (originally issued at \$55
7 million) and \$39.7 million of the 1995 PCBs
8 (originally issued at \$44 million). The debt issued
9 to redeem the outstanding tax-exempt debt will also
10 redeem the commercial paper and bank debt that are
11 currently financing the tax-exempt debt that has been
12 tendered to us. We are assuming that the issued debt
13 will be taxable debt, and we will update the record
14 should we be able to issue tax-exempt debt. Also, the
15 Company's \$55 million Debentures Series A 2000, 7.50%
16 will mature on June 15, 2010 and will be redeemed.

17 Q. Please describe how you developed the cost of long-
18 term debt, and explain the change in the cost of long-
19 term debt between the actual historic data and the
20 projected cost for the forecast period (i.e., the
21 thirteen months ended October 31, 2010.

1 A. Exhibit E-8, Schedule 2, presents the detailed
2 calculation of the cost of the long-term debt at June
3 30, 2008 and for the test year, that is the thirteen
4 months ended October 31, 2010, respectively. These
5 schedules detail each issue of long-term debt
6 outstanding and calculate an effective annual cost for
7 each issue, taking into consideration the original net
8 proceeds to the Company and annual interest costs.
9 The sum of the effective annual cost for all issues is
10 divided by the gross amount of debt outstanding to
11 derive the weighted average cost of long-term debt.
12 The change in the weighted average cost of long-term
13 debt is the result of the actual and contemplated
14 issuances of debentures during the period from August
15 2008 through October 31, 2010 as described above.

16 Q What method have you used to develop interest rate
17 forecasts?

18 A. We have used forecasts (based on the consensus of more
19 than fifty economists) of Treasury rates from the
20 publication Blue Chip Financial Forecasts, plus a
21 spread to Treasuries based on a current estimate of

1 the spread necessary to issue new O&R debt. This
2 approach provides more accurate results than simply
3 using the most current Treasury rates plus the spread
4 from the most recent issue.

5 Why do you advocate using forecast versus current
6 Treasury rates?

7 A. Current rates are significantly affected by the
8 "flight to quality" that has dominated debt markets in
9 the current crisis. Over the longer term, rates can be
10 expected to rise due to the massive amount of Federal
11 aid that is being given, and will need to be provided
12 in the near future, to several industries.

13 Q. Is it reasonable to use the spreads from the most
14 recent issue?

15 A. No. Orange & Rockland last issued debt in August 2008.
16 At that time, the spread over 10-year Treasury issues
17 was 238 basis points. Since that time, spreads on debt
18 issues have increased significantly.

19 Q. Please describe conditions in the long-term taxable
20 debt market.

1 A. Maintaining access to long-term capital funding is
2 critical to the viability of a company such as Orange
3 & Rockland, which has large negative cash flows for
4 its size. For the past three calendar years, Orange
5 and Rockland has averaged \$17 million negative free
6 cash flow and the Company currently forecasts a
7 significantly larger deficit for the next three
8 calendar years. So long as the rates set by the Public
9 Service Commission ("Commission") are significantly
10 lower than the cash cost to operate the business,
11 Orange & Rockland will need to raise new capital
12 regardless of market conditions. It is within these
13 financial constraints that I will describe current
14 market conditions for long-term taxable fixed income
15 securities.

16 The weekly volume of new taxable debt issuance has
17 very volatile since August. The new issue market has
18 been closed on many days. When open, it has been
19 available only to high quality industrial and utility
20 issuers. For utilities, the issues generally have been

1 secured bonds rather than the debentures that Orange &
2 Rockland issues.

3 Q. What does this mean for the Company?

4 A. Because of the importance placed by potential
5 investors on credit quality, having a well-known name,
6 issuing registered debt, an index-sized (\$250 million
7 or larger) issue, and mortgage bonds vs. debentures,
8 O&R is likely to be required to pay even higher rates
9 than are indicated by recent utility debt issues. In
10 addition, there is a growing backlog of utility debt
11 needs that we will be competing with over the next
12 several months.

13 Q. What has been the trend in annual interest rates
14 (yields) for the recent issues?

15 A. Interest rates for newly-issued debt have increased
16 from the mid-200 basis point premiums to comparable-
17 maturity US Treasury bonds that we paid in August of
18 this year for a 10-year maturity to 400 basis points
19 or more, even for 5-year maturities. These rates
20 include a premium of up to 100 basis points on the

1 annual yield to entice investors to purchase newly-
2 issued debt.

3 Q. Can you give us examples of this trend?

4 A. Yes. Southern California Edison Company (rated A2 by
5 Moody's and A by Standard and Poor's) issued
6 30-year first-mortgage bonds on January 14th for 160
7 basis points over 30-year Treasury bond rates. On
8 August 11th, they issued 10-year debt at 155 basis
9 points over Treasury rates. On October 7th, they issued
10 bonds maturing in 5 1/2 years for 340 basis points
11 over 5-year Treasuries. On the same day Detroit Edison
12 (rated A3/A-) issued 5-year secured debt at 400 basis
13 points over Treasuries. In June, they had issued 10-
14 year debt for 170 basis points over Treasuries. On
15 October 16th, Pacific Gas & Electric (rated A3/BBB+)
16 issued 10-year debt at 456 basis points above
17 Treasuries. In February they had issued 30-year debt
18 for 170 basis points over Treasury rates.

19 Q. What impact do you expect this to have on Orange &
20 Rockland debt issuance before and during the rate
21 period?

1 A. Based on current spreads and the need to issue
2 significant debt in a crowded and difficult market I
3 believe that the rates will be far above what we have
4 paid in the last few years.

5 Q. Have you any information from underwriters as to the
6 likely spreads for an Orange & Rockland issue.

7 A. Yes. Citigroup, which acted as underwriter on the last
8 O&R debt issue, estimated current spreads above
9 Treasury bonds as 4.875% for a 10-year issuance and 5%
10 above Treasuries for a 30-year issuance.

11 Q. What would current interest rate be, based on these
12 spreads?

13 A. As of November 10, ten-year Treasuries were trading at
14 a rate of 3.75%, and thirty-year Treasury rates were
15 4.19%. Adding these numbers to the above spreads, an
16 approximate rate for ten-year O&R bonds would be
17 8.625%, and for thirty-year O&R bonds the rate would
18 be 9.19%.

19 Q. Besides the general financial market turmoil, do other
20 factors contribute to the rate Orange & Rockland is
21 likely to pay for new debt?

1 A. Yes. Orange & Rockland is an infrequent issuer, and
2 too small to issue "index-eligible" debentures (debt
3 issues must have principal of \$250 million or more to
4 be included in bond indices) and is thus not as
5 familiar a name as many other utility debt issues.
6 Since it is a less familiar Company and its debt
7 issues are small, it is harder to motivate potential
8 investors to perform the necessary credit work to
9 evaluate the purchase of the securities offered. Non-
10 registered issues pay a premium because of their
11 reduced liquidity in the secondary market.

12
13 Q. Do you have other concerns about the spreads on Orange
14 & Rockland issues?

15 A. Yes. A new issue of O&R debt will need to be
16 attractive relative to the secondary prices (and thus
17 yields) of its previously-issued debt. O&R is at risk
18 for downgrades in its debt ratings based on inadequate
19 nominal and cash rates of return. The Company may very
20 well find itself incurring substantially higher
21 interest costs by issuing "BBB" priced debt when

1 customer rates were set assuming an "A" credit rating.

2 Q. How should this contingency be handled?

3 A. If, during the course of this proceeding, the
4 Company's credit rating is jeopardized, we will so
5 inform the parties and request an update to our
6 interest expense and related costs forecast.

7 Q. Given the uncertainties in the current debt markets,
8 how should changes in these markets over the course of
9 this case be incorporated?

10 A. The Company proposes that the Commission update
11 interest rates as close as possible to the time of the
12 Commission Order in this proceeding, using a rate
13 based on projections of Treasury rates and then-
14 current secondary spreads and new issue premiums.
15 Secondary spreads will be obtained from sources such
16 as Citigroup's "Utility Debt in the Secondary Market",
17 with appropriate adjustments for O&R debt vs. CECONY
18 debt, and new issue spreads from transactions
19 occurring near the date of the Order. Alternatively,
20 knowledgeable underwriters could provide an estimate
21 of spreads for a Company issue. The Company believes

1 that such a rate is more likely to be reflective of
2 the debt costs for debt issued during the rate year.

3 . In a multi-year rate plan, given the likelihood of
4 continuing disruption in the financial markets, the
5 Commission would need to provide some way of tracking
6 debt costs in order to protect the interests of the
7 Company and its customers.

8 Q. Besides the long-term taxable debt issues you describe
9 above, are there other long-term debt components of
10 O&R's capital structure?

11 A. Yes. There are two issues of tax-exempt floating-rate
12 notes, the 1994 A and 1995 A issues.

13 Q. Please describe current conditions in the tax-exempt
14 floating-rate market.

15 A. Unlike Orange & Rockland's commercial paper
16 borrowings, its tax-exempt debt issues have long-term
17 maturities. However, like the commercial paper, the
18 interest rates the Company pays for its tax-exempt
19 debt are short-term in nature. This type of borrowing
20 is known as a "floating rate" borrowing. Historically,
21 tax-exempt floating-rate borrowings have saved utility

1 customers substantial money.
2 Floating interest rates for the Company's tax-exempt
3 debt are set on seven-day cycle. The O&R seven-day
4 floating-rate debt issues are backed by insurance
5 policies issued by specialized financial guarantee
6 insurance companies. The credit ratings of these
7 insurers have been downgraded repeatedly. This caused
8 redemptions by tax-exempt funds no longer legally
9 allowed to own this debt at its new, lower credit
10 ratings. Due to the significant reduction in investors
11 able to purchase this debt, the rate the Company must
12 pay for capital to fund its services to customers has
13 increased materially.
14 These rates have varied with the perceived recovery
15 prospects of the bond insurers, rather than with
16 market rates. The seven-day borrowings - known as
17 variable rate demand notes - have reset as high as 10%
18 for the 1994 A issue. We have repurchased a
19 significant portion of the notes that have been
20 tendered by investors rather than pay these
21 extraordinary rates.

1 The 1994 A issue was originally swapped to a 6.09%
2 fixed rate before issuance. Because of the
3 deterioration in credit quality of the debt insurer,
4 the swap counterparty was able to alter the terms of
5 the swap so that it is no longer economical. If we
6 were to terminate the swap, the Company would incur a
7 termination cost currently estimated at \$12.2 million.

8 Q. Is it possible that the tax-exempt issues may have to
9 be refinanced as taxable issues in light of the
10 demolition of the Lovett plant?

11 A. Yes. We have requested a private letter ruling from
12 the Internal Revenue Service. The purpose of the
13 request is to clarify whether the bonds, which
14 originally funded pollution control equipment at the
15 Lovett and Bowline plants, can remain outstanding now
16 that the Lovett plant is demolished. Should the reply
17 be in the negative, the bonds will have to be re-
18 financed as taxable securities.

19 Q. In light of these circumstances, how do you propose
20 that the Commission treat the outstanding tax-exempt
21 variable rate note issues?

1 A. I propose that the Commission treat these issues in
2 the same manner as in the latest O&R electric case
3 (07-E-0949). As stated on pages 42-43 of the
4 Commission's July 23, 2008 Order establishing rates in
5 that case:

6

7 We also agree with the Company that it is
8 reasonable that it should be able to defer the
9 revenue requirement impacts of transaction costs
10 and interest rate changes should it have to
11 replace tax exempt debt issued in connection with
12 the Lovett Station. In addition, it is reasonable
13 to allow the company to reconcile actual interest
14 and swap costs related to the Pollution Control
15 Debt (including the use of a bank credit
16 facility) to the levels reflected in rates due to
17 the volatility in the market for that debt at
18 this time.

19

20

21

EQUITY

22 Q. Please describe the method used to project the equity
23 balance through the end of the rate year, which is
24 through October 31, 2010.

25 A. The calculation of the average consolidated equity
26 balance of Orange & Rockland and its utility
27 subsidiaries at October 31, 2010 excluding all non-
28 utility subsidiaries and Other Comprehensive Income

1 was projected from the actual per-books balance at
2 June 30, 2008 using the following steps:

3 1. It was assumed that CEI would make the following
4 equity investments in Orange & Rockland: an actual
5 contribution of \$10 million which was made in July
6 2008, and forecasted contributions of \$20 million in
7 March 2009, \$10 million in June 2009, \$10 million in
8 September 2009, and \$10 million in December 2009.

9 2. The forecast earnings for the period July 2008
10 through October 30, 2010 were added to the June 2008
11 Equity balance; and

12 3. Estimated quarterly dividends of \$7.750, or \$31
13 million annually, were subtracted from the balance.

14 Q. What capital structure results from the calculations
15 that you described?

16 A. Exhibit G-8, Schedule 1, Page 1, shows the forecasted
17 capital structure for the 13 months ended October 31,
18 2010, of 48.38% long-term debt, 1.33% of customer
19 deposits, and 50.29% of common stock equity. For the
20 purposes of our requested rate of return, we are using
21 a 48% equity ratio.

1 Q. Mr. Perkins, using your forecasted capital structure
2 and cost of long-term debt and the return on equity,
3 what overall rate of return results?

4 A. The overall rate of return is 9.48% as shown on Exhibit
5 G-8, Schedule 1, Page 1.

6 CAPITAL NEEDS AND INVESTOR CONCERNS

7 Q. What are the financial challenges that face the
8 Company?

9 A. The Company faces four financial challenges both for
10 the rate year and for the foreseeable future.

11 Q. What is the first financial challenge for the Company?

12 A. The most readily noticeable financial challenge for
13 the Company arises from the fact that its business is
14 mature and capital intensive. Capital intensity can be
15 demonstrated by the fact that the ratio of net plant
16 per dollar of revenues is \$1.2 for the Company versus
17 \$.10 for the average S&P 500 company. The maturity of
18 the Company's facilities mean that service is
19 currently provided using assets of a very different
20 average cost than the incremental cost of new
21 facilities. Thus, the Company's depreciation rates,

1 which reflect historic book values, are small relative
2 to its current capital costs, returning only 33% of
3 its capital expenditures in the form of depreciation
4 in 2007. Due to the long authorized depreciation
5 lives, this dynamic is likely to continue for a long
6 time. By way of comparison, the average S&P 500
7 company recovered 140% of its capital expenditures
8 through depreciation in 2007, and the average company
9 in the Bloomberg electric utilities recovered 48%.

10 Q. Would you please describe the second financial
11 challenge the Company faces?

12 A. The Company is, and will be, challenged by its
13 unusually weak cash flows as compared to other
14 businesses. The weak cash recovery on plant arises
15 from the capital expenditure dynamics described above.
16 But, even if the modest increases in customer demands,
17 net of the assumed energy efficiency plans, were not
18 considered, replacement needs alone would
19 substantially exceed the cash generated through
20 depreciation recoveries. Only approximately 20% of the
21 gas is for new business. The challenge that this

1 dynamic presents is that the Company will have a
2 relatively poor cash flow profile when compared to
3 other businesses for a long period of time. It is
4 important to understand that the Company's obligation
5 of universal reliable service means also that it must
6 be ready to respond, from an operating and financial
7 standpoint, to contingencies. By that I mean
8 unexpected events or catastrophes that put the Company
9 to the test of maintaining essential services. To say
10 that such events or catastrophes are not predictable
11 or quantified in a given test period does not
12 adequately respond to this vital concern.

13 Q. What is the third financial challenge faced by the
14 Company?

15 A. Third, the Company is subject to several restrictions
16 that limit its ability to react to unfavorable
17 circumstances. As mentioned above, it must provide
18 service as demanded, even if doing so entails
19 significant investment upon unfavorable terms. It
20 cannot refuse to provide service to new or
21 unprofitable customers. It also cannot reach beyond

1 its franchised area to serve attractive new customers.
2 The Company's assets are immovable; unlike those of
3 most companies they cannot be used in a different
4 location or business, their usefulness and
5 profitability are tied to providing natural gas
6 delivery service in New York. Also, unlike other
7 companies, O&R has a limited ability to retain the
8 advantages of its efforts to improve its efficiency
9 and thus lower its costs of doing business for the
10 benefit of its owners, as these benefits are fully
11 allocated to customers each time rates are reset.
12 Finally, O&R's parent is restricted from investing in
13 certain assets in the area it knows best, New York.

14 Q. What is the fourth financial challenge facing the
15 Company?

16 A. The financial challenges described previously all
17 converge in the Company's fourth challenge which is
18 that it must approach the markets for additional new
19 capital on an annual basis. The Company needs to fund
20 continuously, but, due to its size and the relative
21 unfamiliarity of investors with the Company each

1 financing requires an active marketing effort to
2 reacquaint investors with its name and reassure them
3 as to its suitability. Each time, investors will
4 assess the risks they would bear upon investing in the
5 Company due to the challenges identified above. Their
6 assessment of these risks is, and will be, priced in
7 the market each of the times that the Company seeks
8 new capital in the years ahead.

9

10 Q. Would you please describe the Company's capital needs?

11 A. Other Company witnesses have detailed the investment
12 needed to maintain the Company's infrastructure, to
13 maintain service reliability, to support economic
14 growth, and to attend to other policy goals. Orange &
15 Rockland currently has a capital expenditure program,
16 determined by the need to update and expand the
17 infrastructure, which exceeds that of any comparable
18 period. In turn, the amount of capital that must be
19 raised far exceeds the levels of the past.

20 The Company will have to raise \$360 million in debt
21 between June 30, 2008 and October 31, 2010, including

1 \$99 million of debt needed to refinance the tax-exempt
2 issues.

3 To put this in context, Orange & Rockland's total debt
4 as of June 30, 2008 was \$347 million. The Company will
5 have to issue, within a period of a little more than
6 two years, debt equal to almost 104% of its debt
7 balance as of June 30, 2008.

8 In turn, Orange & Rockland will need equity infusions
9 from its parent, CEI, of \$60 million from June 2008 to
10 October 30, 2010. This \$60 million of equity
11 represents 13% of the Company's equity balance as of
12 June 30, 2008 (excluding equity in non utility
13 subsidiaries and other comprehensive income).

14 Q. What is the ultimate source of this equity capital?

15 A. The equity will be raised from investors by CEI.

16 Q. What is the implication of these large capital needs?

17 A. To raise this capital at a reasonable cost, Orange &
18 Rockland, and its parent, CEI must remain attractive
19 investments to both debt and equity investors. To
20 remain attractive to these investors, Orange &

1 Rockland must continue to receive fair and reasonable
2 treatment from its regulators.

3 Q. Mr. Perkins could you please describe the state of the
4 financial markets and the implications that changes in
5 the financial markets may have for O&R and CEI during
6 the rate period under consideration?

7 A. The condition of the financial markets, and indeed the
8 US and global economy, have deteriorated significantly
9 in recent months. What was believed in the spring to
10 be confined to problems with sub-prime residential
11 mortgages has exploded into a global crisis in the
12 financial services industry with spillover
13 implications for the global economy. For most of this
14 decade, a misplaced confidence in the value of
15 financial assets and a dramatic increase in the amount
16 of leverage in the US and global financial system
17 resulted in a dramatic underestimation in the amount
18 of risk in our financial system.

19 JPMorgan has estimated that as much as \$6 trillion of
20 global lending capacity has been destroyed as a
21 consequence of the capital losses in the financial

1 industry. In addition, the re-acquisition by the banks
2 of hundreds of billions of dollars of financial assets
3 that they believed they were rid of will further
4 restrict the banks' ability to help individuals and
5 corporations such as O&R and CEI raise new capital.

6
7 The adverse consequences of this crisis will take
8 several forms for Orange & Rockland and CEI during the
9 rate period and beyond. First, capital will be more
10 expensive and less readily available than before.
11 Second, based on current financial markets, we expect
12 to have significant new funding responsibilities for
13 our pension and other post-retirement benefit plans
14 for our employees. Third, the electricity and gas
15 markets that have benefited from the active
16 participation of financial services companies will now
17 suffer from their withdrawal from this market. And
18 fourth, the service area will undoubtedly suffer,
19 resulting in higher collection costs and uncollectible
20 bills and a continuing temptation to make the Company

1 an even larger tax collecting agent than it already
2 is.

3

4 Q. How do bond investors evaluate Orange & Rockland debt
5 in particular?

6 A. For most investors, the credit ratings assigned by the
7 credit rating agencies are the threshold basis for
8 evaluating individual corporate credits such as Orange
9 & Rockland.

10 Q. What are the current ratings on Orange & Rockland
11 debt?

12 A. The long-term debt ratings are A2, A-, and A by
13 Moody's, Standard and Poor's ("S&P"), and Fitch,
14 respectively. The Outlook is Negative for Moody's and
15 Stable for S&P and Fitch. The short-term debt is
16 rated P-1, A-2, and F2 (by Moody's, S&P, and Fitch).
17 Again, Moody's Outlook is Negative.

18 Q. Please describe the credit evaluation process
19 undertaken by the rating agencies.

20 A. Credit ratings reflect an agency's independent
21 judgment of the credit-worthiness of a company based

1 on the business and financial risks of that entity.
2 Of the agencies, S&P has documented their analytical
3 methods in the greatest detail, and we have had
4 extensive discussions with that agency about specific
5 aspects of their process. It is my understanding that
6 the process employed by other credit agencies is
7 generally similar in nature.

8 Q. Please continue.

9 A. S&P looks at several qualitative factors that they
10 reflect in their determination of a utility's business
11 risk. These include regulation, markets, operations,
12 competitiveness, and management. The relative
13 importance of each category depends on the nature of
14 the utility's business as stated recently by S&P in
15 Standard & Poors' New Business Profile Scores Assigned
16 for U.S. Utility and Power Companies; Financial
17 Guidelines Revised (page 6):

18 The emphasis placed on each category may be
19 influenced by the dominant strategy of the
20 company or other factors. For example, for a
21 regulated transmission and distribution company,
22 regulation may account for 30% to 40% of the
23 business profile score because regulation can be
24 the single-most important credit driver for this
25 type of company. Conversely, competition, which

1 may not exist for a transmission and distribution
2 company, would provide a much lower proportion
3 (e.g., 5% to 15%) of the business profile score.

4
5 The final result of this qualitative business risk
6 analysis is a business profile score, ranging in five
7 steps from Excellent to Vulnerable.

8 Q. What is Orange & Rockland's (and CEI's) business
9 profile score?

10 A. Its score currently is Excellent. This score is shared
11 by approximately 75% of all electric utility holding
12 companies and their subsidiaries in the U.S. and does
13 not significantly distinguish it from other utilities
14 raising capital.

15 Q. Do the other rating agencies look at business risk as
16 well?

17 A. Yes, though they do not quantify that risk in the same
18 manner as S&P does. For example, Moody's looks at
19 several dimensions of risk, including the degree of
20 government support, the percentage of non-regulated
21 business, and the nature of regulation. In "Rating
22 Methodology: Global Regulated Electric Utilities"
23 (March 2005, page 4) Moody's states:

1 The second step in the methodology is to assess
2 the credit support that is gained from operating
3 within a particular regulatory framework. Moody's
4 considers each regulatory system and assesses
5 whether there is a high or low expectation of
6 predictability in the system and whether operators
7 can reasonably expect to recover their costs and
8 investments through regulator-approved revenue
9 increases.

10
11 And on the same page they state:

12
13 We also classify entities into the following four
14 categories based on a comparative assessment of
15 the predictability and stability of regulated
16 cashflows for a company operating under a
17 particular regulatory framework...

18
19 Q. Are there specific risks that the agencies are likely
20 to be concerned with in the current environment?

21 A. Yes. There are industry wide risks such as the need
22 for new generation, and a growing need by all
23 companies for new capital that will mean competition
24 for investor money and higher costs. There are also
25 issues that are specific to the state of New York such
26 as the potential for a return to long-term energy
27 contracting, and mandated efficiency programs that
28 would raise per-unit costs.

29
30
31 Q. Do you have any indications as to where the agencies

1 see risk at present?

2 A. Moody's, in its "Industry Outlook- US Electric
3 Utilities", (December 2006, page 3) listed the
4 following:

5
6 Rating drivers likely to increase credit risk for
7 issuers in 2007 include:

- 8
- 9 • Increasing regulatory pressures, with some
10 regulators seeking to delay rate increases for
11 cost recovery due to rate shock concerns;
12
 - 13 • Political intervention in the regulatory
14 process by state and local government
15 officials;
16
 - 17 • Uncertainty resulting from the end of
18 transition or market development periods;
19
 - 20 • Higher debt burdens at utilities due to cost
21 deferrals and regulatory delays of cost
22 recovery;
23
 - 24 • Significant increases in capital spending,
25 particularly for environmental compliance;
26
 - 27 • A substantial need for investment in new
28 generation, as well as transmission and
29 distribution system improvements; and
30
 - 31 • Overly biased shareholder reward strategies.

32

33 Thus, Moody's attributes significant risk to the
34 regulatory and political environment, combined with
35 the high level of investment needed. On page 4, they
36 reiterate the key role of regulation in determining

1 credit quality:

2 The industry also faces substantially higher
3 capital expenditure pressures over the next
4 several years, much of it for environmental
5 compliance, but also for new generation and for
6 expansion and improvement of transmission and
7 distribution systems. As a result, we expect to
8 see more rate filings in coming years, with a
9 utility's regulatory environment becoming an
10 increasingly important determinant of overall
11 credit quality.
12

13
14 In addition, Moody's has articulated their view of the
15 increasing risk in the industry in their report *Storm*
16 *Clouds Gathering on the Horizon for the North American*
17 *Electric Utility Sector* (August 2007):

18 The storm clouds referenced in this report
19 essentially point to a potential increase in the
20 business and operating risk profile for the
21 sector. In our opinion, the rising costs and
22 investment needs will have a direct impact on all
23 three financial statements: income, cash flow and
24 balance sheet. As a result, one of the biggest
25 challenges for utility companies will be to seek
26 and receive timely recovery of prudently incurred
27 expenses. In addition, the substantial increases
28 in capital expenditures will have a material
29 impact on the sector's ability to generate free
30 cash flow.
31

32

33

34

35 Q. What quantitative financial indicators do the agencies

1 use to determine their credit ratings?

2 A. S&P uses a variety of financial indicators. They have
3 indicated that the most important ones are those
4 related to cash flow coverage of interest and debt,
5 and the ratio of total debt to total capital. The
6 specific key ratios that are considered by S&P are:

- 7 1. Funds from Operations/Average Total Debt;
8 2. Funds from Operations Interest Coverage; and
9 3. Total Debt/Total Capital.

10 Q. Does Moody's use similar ratios?

11 A. Yes. They use the following six core ratios:

- 12 1. (Funds from Operations-Dividends)/Debt;
13 2. Funds from Operations/Debt;
14 3. FFO/Interest;
15 4. Debt/Asset Value;
16 5. EBITDA Margin; and
17 6. (Funds from Operations-Dividends)/Capital
18 Expenditure.

19 They have indicated that the first four ratios are the
20 primary ratios, and the second two are the secondary
21 ratios. The common element for both agencies is the

1 emphasis on cash flow versus debt and interest.

2 Q. How do the business risk positions affect the
3 quantitative measures used by the rating agencies?

4 A. The higher the business risk the more rigorous the
5 target level for a given rating
6 Regulation, as an important component of the
7 qualitative analysis that leads to a business risk
8 profile, is thus a key determinant of the level of
9 financial ratio targets that are used in determining a
10 company's debt rating.

11 Q. Is Orange & Rockland free of operating risk?

12 A. Not at all. As Moody's explained in "Rating Action:
13 Orange and Rockland Utilities, Inc" (September 5,
14 2006):

15 The ratings also consider the potential for lower
16 operating resilience given the relatively small
17 scale of the companies' stand-alone operations and
18 revenue generating capacity.

19

20 Q. What does Moody's say currently about the strength of
21 Orange & Rockland's credit ratios?

1 A. In "Credit Opinion: Orange and Rockland Utilities, Inc"
2 (March 21, 2008 at page 1) Moody's says:

3 Some of O&R's historical credit metrics have been
4 somewhat weaker than what we typically expect to
5 see from "A" rated entities in this sector. We
6 believe that O&R will be challenged to achieve
7 substantive improvement in its key credit metrics
8 over the next several years because we are now
9 more skeptical in our view as to how supportive
10 the NYPSC might be for New York-based utilities
11 due to the litigated outcome of the CECONY
12 electric case outlined above in the Recent Events
13 section and the growing propensity for the NYPSC
14 to rely on very low allowed ROE's when setting new
15 rates.

16 Q. What does Moody's say concerning the impact of
17 regulation?

18 A. They say (Page 2 of the same article):

19 Effective March 20, 2008, Moody's affirmed the
20 ratings of CEI, CECONY, and O&R but revised the
21 rating outlooks for all three companies to
22 negative from stable. This action reflected our
23 growing concern with regard to the ability of the
24 three companies to achieve a materially stronger
25 financial profile given the persistent weakness
26 in key credit metrics for the companies relative
27 to what we typically see for companies in the "A"
28 rating category coupled with the decision by the
29 NYPSC with respect to CECONY's latest rate case.
30 We believe a stronger financial profile is
31 necessary to compensate for the rising business
32 and operating risks that go in tandem with the
33 exceptionally large capital program that CECONY
34 and O&R face over the next several years. The
35 change to negative rating outlooks for the
36 companies also takes into account our more

1 guarded view than we have had in the past about
2 the extent to which the New York regulatory
3 environment will be supportive in future rate
4 case decisions for CECONY and O&R. In particular,
5 we note the 9.1% allowed return on equity (ROE)
6 used by the NYPSC in late 2007 for O&R's rate
7 investigation related to its electric operations
8 (this compares to 10.4% previously) and the recent
9 fully litigated decision in CECONY's electric rate
10 case, which granted only about 35% of the \$1.2
11 billion rate increase requested (new rates
12 effective April 1, 2008), also based on a 9.1%
13 allowed ROE (reportedly the lowest ROE granted to
14 an electric utility in over 30 years). We view
15 this as an additional sign of the increasing
16 propensity for the NYPSC to extend the cash
17 recovery period for certain previously incurred
18 costs, take a less supportive view with respect to
19 certain types of future costs, and base decisions
20 on a much lower authorized ROE.

21
22 Q. Why did Moody's place O&R on a Negative Outlook?

23
24 A: They state (page 5):

25
26 O&R's negative rating outlook, which mirrors the
27 negative rating outlook for CEI and CECONY,
28 reflects our evolving views concerning the
29 relative weakness in its key credit metrics
30 relative to what we typically see for companies
31 in the "A" rating category for this sector, and a
32 heightening of concerns about a clouded path to
33 achieving a materially stronger financial
34 profile, which we believe is necessary to
35 compensate for the rising business and operating
36 risks that go in tandem with the exceptionally
37 large capital program that CECONY and O&R face
38 over the next several years. The negative outlook
39 also takes into account our more guarded view
40 than we have had in the past about the extent to
41 which the New York regulatory environment will be

1 credit supportive in future rate case decisions
2 for O&R and CECONY.

3
4 Q. What could cause Moody's to lower the rating on O&R's
5 debt?

6
7 A. On page 5 Moody's says:

8
9 O&R's ratings could be downgraded if future
10 regulatory actions continue to not be
11 sufficiently supportive of credit quality
12 commensurate with the current rating level.
13 Moreover, credit quality could suffer if
14 substantial capital spending is not prudently
15 financed with a mix of debt and equity. O&R's
16 ratings could also be reconsidered if it is
17 unable to demonstrate visible signs of being able
18 to achieve on a sustainable basis CFO Pre-W/C to
19 debt and interest of at least the high teens and
20 comfortably above 4x, respectively, over the next
21 18 months.

22
23 Q. Has S&P lowered O&R's ratings?

24
25 A. Yes, it has. On March 28 S&P lowered the rating
26 by two levels.

27
28 Q. What does S&P say currently about the strength of CEI's
29 credit ratios?

30 A. S&P, as opposed to Moody's, treats ratios on a
31 consolidated basis. S&P is concerned that ratios are
32 weak for the ratings that are currently on the debt
33 securities, which have already been downgraded to A-.
34 For example, in "Orange and Rockland Utilities Inc."

1 (June 12, 2008, at p. 1) S&P includes weak financial
2 ratios for the current rating as a major rating factor.

3 Q. Has Fitch downgraded O&R as well?

4 Q. Yes, they did so on March 28 in reaction to the
5 Commission's rate order issued March 25, 2008 in
6 CECONY's last electric base rate case ("March 2008
7 Order").

8 Q. Are there extra impacts on the cost of issuance of
9 tax-exempt debt from a credit downgrade?

10 A. Yes. If Moody's rating of O&R is lowered one step from
11 A2 to A3, NYSERDA will no longer allow O&R to issue
12 tax-exempt debt without a letter of credit, even if
13 such debt could otherwise be sold without the credit
14 support. Letters of credit have significantly
15 increased in cost, to at least a full percent per
16 annum.

17

18 CREDIT QUALITY AND SHORT-TERM BORROWING

19

20 Q.. Are there other impacts of lower credit quality?

21 A. Yes. The next step in the deterioration of the

1 Company's credit would be the loss of its P-1 short-
2 term debt rating from Moody's. The short-term ratings
3 affect the Company's ability to issue short-term debt
4 and the cost of the short-term debt, the cost of
5 acquiring and maintaining revolving credit
6 arrangements from banks, the Company's need to post
7 more financial collateral to acquire energy on behalf
8 of our customers, and as mentioned above, potentially
9 the Company's ability to issue tax-exempt debt without
10 credit support.

11 A. Please describe how these impacts occur.

12 Q. The short-term debt (i.e., commercial paper) market is
13 very credit- and event-sensitive. By its nature, it
14 is a market that is accessible only by high-quality
15 issuers, as the buyers are investing their ready cash
16 and therefore must have near-absolute assurance of
17 their safety and liquidity.

18 Recent problems in the tax-exempt auction rate market
19 resulted in high profile firings of corporate officers
20 who misjudged the liquidity of their investments.

21 These experiences reinforce the risk averseness of

1 this otherwise very attractive source of funding.
2 Particularly in times of stress, issuers with solid
3 but not excellent credit can find it difficult to sell
4 their commercial paper to investors, particularly for
5 periods longer than overnight and, even if the issuer
6 were able to find buyers, they will often pay
7 significantly higher premiums for funds. If the
8 ratings drop further, the borrower no longer has
9 access to the commercial paper markets and therefore
10 must borrow from commercial banks through revolving
11 credit arrangements. These arrangements are
12 significantly more expensive under most market
13 conditions.

14 Q. Please address the impact of the current financial
15 crisis on short-term, commercial paper financing.

16 A. Commercial paper borrowings are short-term—often
17 overnight—unsecured promises to pay back money
18 borrowed. Because these borrowings are not secured,
19 the purchasers of these instruments have required
20 issuing companies to have a credit facility provided
21 by a group of banks that was available to repay the

1 commercial paper to the extent the company was not
2 able to do so.

3 Historically, commercial paper was purchased by
4 taxable money-market funds. The bankruptcy of Lehman
5 Brothers caused a number of money market funds to lose
6 principal for the first time in their history. These
7 losses prompted a rush of investors out of money-
8 market funds. In the wake of the Lehman bankruptcy,
9 Orange & Rockland's A-2/P-1/F2 short-term credit
10 rating and small size has resulted in greater
11 difficulty in finding investors for its commercial
12 paper. As a consequence, it has paid much more on
13 many days than the benchmark rate in order to borrow.
14

15 In a good financial market environment, the credit
16 rating might have modestly increased our financing
17 costs. This year however, due to the deterioration of
18 the financial markets, commercial paper costs in
19 general have increased dramatically relative to the
20 benchmark rate. The Federal Government has established
21 a facility for A-1/P-1 rated issuers to sell their

1 paper to the government. Even before this significant
2 differentiation between issuers, commercial paper like
3 the Company's that has a split rating—that is,
4 commercial paper that includes "2" ratings as well as
5 "1" ratings— became more difficult and expensive to
6 place. We have had to pay as much as 300-600 basis
7 points, (or 3% to 6% on an annualized basis) above the
8 effective Fed Funds rate during September and October
9 2008. Recently rates for commercial paper have eased
10 but the markets are still not normal and Orange &
11 Rockland finds it better to borrow from its sister
12 utility than to brave the commercial paper market on
13 its own.

14 Q. Has funding been available?

15 A. As mentioned, O&R has been funded through commercial
16 paper borrowings by CECONY, as permitted by FERC
17 authorization. Indicative rates for Orange & Rockland
18 have been significantly higher than CECONY's rates on
19 certain days. To date, CECONY has been able to find
20 investors to meet the needs of both it and O&R and
21 neither company has had to fall back on the banks that

1 provide their credit facilities. CECONY's funding
2 strategy has been to lengthen the maturity of its
3 commercial paper borrowings over month- and quarter-
4 ends in order to minimize its exposure to the
5 extraordinary volatility of these periods. Other
6 utility companies, with similar or slightly lower
7 credit quality, have already been forced to borrow
8 from their bank lines of credit.

9 Q. Why does O&R need revolving credit facilities?

10 A. The Company has maintained revolving credit facilities
11 for many years for several reasons. First, revolving
12 credit facilities are required as assurance to
13 investors that a company has the means to repay
14 outstanding commercial paper should there be market
15 disruptions. Commercial paper buyers and rating
16 agencies expect 100% coverage of the commercial paper
17 outstanding by bank credit facilities. In addition, as
18 mentioned above, bank facilities can be used for
19 direct borrowing in times of crisis, though at a
20 significantly higher price under most conditions than
21 commercial paper borrowing. Finally, bank facilities

1 provide a source of letters of credit, which O&R uses
2 to provide collateral, primarily to guarantee its
3 purchases of energy for its customers.

4 Q. How are bank revolving credit arrangements affected by
5 ratings changes?

6 A. In the short-term, the cost of the facility is a
7 function of a company's credit rating. Virtually all
8 US corporate revolving credit agreements include a
9 pricing grid which adjusts the cost of the facility
10 based on the rating of the borrower. In the longer
11 term, if a company's credit rating falls too far,
12 certain lenders may be unwilling to renew such
13 facilities.
14 More recently there have been concerns that certain
15 banks may exit all or part of the corporate lending
16 business due to their own credit weakness. At the very
17 least, bank funding costs will rise at the next
18 renewal; both the upfront costs to put the facility in
19 place as well as the periodic costs for outstanding
20 balances. We have heard of increases in upfront costs
21 on the order of ten times current costs or more,

1 and/or the imposition of market-sensitive pricing
2 which would mean that borrowing costs would track the
3 very volatile credit default swap market rates.

4 REGULATION AND CREDIT QUALITY

5 Q. What is the impact of the regulatory process on the
6 key credit ratios you detailed above?

7 A. I have detailed above the importance of the state
8 regulatory environment for rating agency determination
9 of the business risks of a utility. In this section I
10 will discuss the direct impact of regulatory rate-
11 setting on the ratios.

12 Cash flow is the key component in determining the
13 strength of the credit ratios. Revenues increase the
14 funds from operations by increasing cash flow. This
15 effect will directly increase the key coverage ratios,
16 Funds from Operations to Total Debt and the Funds from
17 Operations, by increasing the numerators. Because the
18 increased cash flow reduces the need for financing
19 (and the associated interest), there will be a second
20 positive impact on all three ratios.

21 Q. Are there particular reasons for the importance of net

1 income to the cash flows of Orange & Rockland?

2 A. Yes. As discussed above, relative to many other
3 utilities, Orange and Rockland's capital additions for
4 the foreseeable future significantly exceed its
5 current depreciation. In addition, the levels of
6 deferred tax that contribute to cash flow are expected
7 to remain low. Thus, cash flow for Orange & Rockland
8 will rely to a greater extent on earnings than would
9 be the case for other utilities

10 Q. Why are allowed returns on equity and allowed equity
11 as a proportion of the capital structure important to
12 debt investors as well as equity investors?

13 A. Debt investors are concerned about the amount of
14 equity subordinate to them in the capital structure
15 and the returns available for stockholders for two
16 primary reasons. First, if a company is able to
17 attract new stock investment, it increases the debt
18 investors' likelihood of being paid interest and
19 principal when due. Second, returns for stock
20 investors provide a cushion when the business is
21 struggling. In difficult times, cash payments to this

1 part of the Company's capital can be suspended until
2 the business improves.

3 Q. You have given rating agency views of trends in New
4 York regulation. Are there any formal rankings of this
5 regulation versus that of other states?

6 A. Yes. Regulatory Research Associates, a service of SNL
7 Financial ("RRA") and Lehman Brothers have produced
8 such rankings.

9 Q. How does RRA rate the regulatory climate in New York?

10 A. For several years RRA had rated New York regulation as
11 an Average-2, the middle segment of the Average
12 category. In reaction to the October 2007 electric
13 rate order for O&R they lowered the category to
14 Average-3. At this level, 33 states (including the
15 District of Columbia) have ratings higher than New
16 York, while nine other states have equal ranking and
17 only eight have lower rankings. In its "Final Report"
18 on the O&R electric rate order RRA stated:

19 This New York Public Service Commission (PSC)
20 decision for Orange and Rockland Utilities (ORU),
21 a subsidiary of Consolidated Edison, Inc., is

negative from an investor viewpoint. This case was initiated as an earnings investigation by the PSC, in response to ORU's relatively strong earnings over the previous three-year rate plan, and the fact that the plan expired without a new rate plan in place. While the PSC determined that the company's rates should remain unchanged, the Commission adopted a 9.1% return on equity (ROE), which, to our knowledge is the lowest ROE authorized an energy utility nationwide in at least the last 30 years. We note that prior to this decision for ORU, the lowest equity return was 9.45%, which was authorized by the Arkansas Public Service Commission in a 2005 gas rate decision for CenterPoint Energy Arkansas Gas. The low return authorization in that case reflected a penalty related to the Arkansas Public Service Commission's determination that the company's record keeping was deficient. We should point out that in cases without rate settlements, the New York PSC, historically, has authorized ROEs that

1 were well below prevailing nationwide averages;
2 however, this return authorization was far below
3 our expectations and has lowered the bar for the
4 industry. Therefore, we are lowering our rating
5 of New York regulation to Average/3 from
6 Average/2.

7 Q. How does RRA describe the New York regulatory climate?

8 A. RRA (in its profile of the New York PSC) says:

9 "The PSC has a long history of authorizing below-
10 industry-average returns on equity (ROEs). Over
11 the past year, the Commission adopted a 9.1% ROE
12 in three rate proceedings -- we note that this
13 ROE is, by far, the lowest return authorized
14 nationwide in at least the last 30 years."

15 Q. O&R's electric ROE return granted in the last case was
16 9.4%. Should this assuage investor concerns?

17 A. No. This return is still lower than that for any other
18 utility outside New York State (except for one that
19 has an equal ROE), and was only achieved because of
20 the 30 basis point stayout premium.

21 Q. How does Lehman rank New York's regulatory climate

1 relative to those in other states?

2 A. Lehman Brothers, on page 32 of its publication "Public
3 Utilities-Capital Consequences" (June 3, 2008) lists
4 the state regulatory commission in order from 1 to 48
5 (with 1 being the lowest cost of capital based on
6 strength of regulatory support). New York is rated
7 45th.

8 Q. Why is the availability of reasonably-priced capital
9 so important to utilities and their customers?

10 A. First, because of the dramatically lower returns on
11 the historic book investment made by investors in the
12 business utilities have much less internally generated
13 cash with which to replace assets that have reached
14 the end of their useful lives. An additional
15 difference between the regulated utilities and
16 industrial businesses is that timely capital
17 investment is much less voluntary for the utility.
18 Increased maintenance and service improvements are
19 required to meet increasing expectations of customers
20 and other constituents and myriad new and growing
21 regulatory requirements. This is in addition to the

1 statutory requirement that a utility accommodate new
2 businesses, even when the utility faces financial
3 stress. Debt issued during difficult times will
4 result in increased costs for the customers for at
5 least several years. Equity sold at a low price
6 reduces stock investor returns forever.

7 Q. How do credit ratings affect customers?

8 A. Credit ratings impact both the cost and availability
9 of long and short term financing. The exact level of
10 the impact will vary with the amount of financing
11 needed and the financial climate. In times of crises
12 (whether related to a company, industry, or the
13 market), the costs will be significantly higher for
14 lower-rated companies.

15 A second effect of lower credit ratings, which is
16 particularly important in these times of volatile and
17 high fuel and purchased power costs, is the need to
18 post additional collateral for energy transactions if
19 credit ratings fall. This collateral, in turn, would
20 have to be financed at higher interest rates for a
21 lower-rated company. Independent system operators are

1 discussing the imposition of stricter credit
2 requirements for their participants which could
3 increase borrowings to meet collateral needs.

4 THE ROLE OF INVESTORS IN FUNDING THE COMPANY

5 Q. How do investors evaluate the decision to invest in
6 O&R and its parent company as opposed to investing in
7 the myriad of other investment opportunities?

8 A. Investors evaluate their potential returns in light of
9 the characteristics of those returns: their magnitude,
10 timing and probability.

11 Q. What forms might this evaluation take?

12 A. In a typical business, the investor identifies the
13 potential return as coming from one of two sources: a
14 cash income stream from dividends and the potential to
15 sell the stock in the future for a higher price. For
16 fundamental long-term investors, the assumption as to
17 a higher sale price in the future generally results
18 from improvement in earnings per share rather than an
19 assumption that the stock can be sold at a higher
20 multiple of those earnings.

21 Q. Are there additional aspects of the evaluation process

1 for investors in utilities?

2 A. Yes. In a regulated industry, the controlling
3 determinant of returns is the regulator. The regulator
4 limits the profitability of the subject company by
5 setting capitalization, equity rates of return, the
6 opportunity to actually achieve that return, the
7 symmetry or asymmetry of potential gains and losses
8 for performance and for recovery of uncontrollable
9 costs, and the restrictions on lines of business that
10 the company can enter.

11 Q. How would an equity investor evaluate the returns
12 offered to New York utilities as to their magnitude,
13 timing and probability?

14 A. There are four significant factors in an equity
15 investor's assessment of New York utility regulation:
16 capitalization (proportion of equity), rate of return
17 to equity, symmetry of equity returns, and
18 restrictions on the scope of the business. To make
19 this assessment, an obvious place for an equity
20 investor to start is the basic parameters of rate
21 plans from a given jurisdiction.

1 Q. How is the first identified return consideration
2 addressed by New York rate orders?

3 A. As to the first factor, capitalization, over the past
4 several years, New York State has maintained
5 relatively consistent proportions in the
6 capitalization of its subject utilities, thus
7 providing some encouragement to a potential equity
8 investor in a New York utility. RRA reports on
9 regulatory decisions across the United States. Using
10 their data, a plot of authorized equity capitalization
11 can be shown for the period 1992 through the present.

12 Q. Have you prepared an exhibit demonstrating this point?

13 A. Yes. The data is presented as (Exhibit G-8, Schedule
14 3). Equity as a percentage of total capital has
15 increased modestly over the period for New York
16 utilities, but other jurisdictions have allowed their
17 utilities to more aggressively improve their balance
18 sheets. In the current economic and financial
19 environment, investors are more than ever concerned
20 about the security of their investments. Investors
21 are demanding significantly higher returns from

1 companies with financial risk.

2 Q. Is the second return consideration treated similarly?

3 A. The second factor, the level of returns on equity, is
4 the most important of the four factors for an equity
5 investor because it provides the clearest signal in
6 the rate order of the regulator's willingness to
7 balance the needs of investors and customers. For the
8 investor, this decision goes to the social contract
9 inherent in monopoly regulation which is that the
10 monopoly rent opportunities of the owners are foregone
11 in return for institutionalization of the monopoly
12 franchise and a fair return on capital committed to
13 the business. The lower the authorized return on
14 equity, the more likely it is that the regulator
15 weighs lightly its side of the social contract. Large
16 institutional investors continue to express dismay at
17 the recent authorized returns for New York utilities
18 relative to the other jurisdictions in the United
19 States. Allowed returns in New York have been lower
20 than the national average throughout the period and
21 have increasingly departed from the practice

1 elsewhere.

2 Q. Have you prepared an exhibit demonstrating this point?

3 A. Yes, my (Exhibit G-8, Schedule 4) In particular in
4 recent orders, Orange & Rockland and CECONY have
5 received the lowest authorized returns on equity in
6 the United States in at least the last thirty years.
7 In accepting a three-year agreement in the last
8 electric case, O&R was only able to achieve a rate of
9 return which was exceeded by all but one non-New York
10 utility. In past cases, Staff has argued that each of
11 the rate cases in the RRA database is unique, and
12 therefore no meaningful conclusion can be drawn. While
13 I would agree that each is unique, it must also be
14 granted that it is equally obvious that the
15 differences in the authorizations cannot always be
16 such that New York companies should consistently and
17 deservedly be granted the lowest returns in the
18 country. In fact, the record low returns for Orange &
19 Rockland's and CECONY's electric service were granted
20 in the face of increased penalties and a lack of
21 positive incentives

1 Q. How would an investor assess the third factor: the
2 symmetry of potential returns?

3 A. As noted above, the potential return profile in New
4 York has increasingly skewed below the authorized rate
5 and the trend in this direction has accelerated in
6 recent years. There is ample opportunity through
7 penalty-only performance mechanisms and one-way true-
8 ups of unavoidable costs, which have increasingly been
9 imposed in rate orders, to provide significantly worse
10 returns than the authorized return. Further, there is
11 a mandatory requirement of productivity, and all of
12 the productivity improvements that the Company is able
13 to achieve are captured for customers at the beginning
14 of each new rate period. All of these aspects of rate
15 cases take away any symmetry in expected returns,
16 adding to risk. Operating risk, in the form of
17 increased costs to respond to unusual events, also
18 creates pressure on the investors' return. The
19 combination of a continuing downward trend in the
20 financial aspects of Commission rate orders, coupled
21 with increasing risks of new and additional regulatory

1 requirements, combine to increase the risks perceived
2 by a potential equity investor in the Company.

3 Orange and Rockland's results under the current gas
4 rate plan illustrate this.

5

6 Q. Does the use of an adjustment clause to pass through
7 changes in energy costs to customers offset the
8 investor's weighing of the low and skewed returns
9 offered in New York?

10 A. No. Energy recovery mechanisms have been in place for
11 the Company, as well as for many other utilities, for
12 many years. While eliminating certain aspects of
13 downside risk, energy recovery clauses also provide no
14 benefit to an equity investor, so are a neutral factor
15 at best. Over the same period, other loss protections
16 and potentials for earning a higher return have
17 eroded. In addition, as energy costs rise, customer
18 bills rise. Bill increases due to higher commodity
19 costs do not benefit the investor, but they do
20 contribute to pressure on the regulator to respond by
21 imposing more stringent cost recoveries and lower

1 rates of return on the Company.

2 Q. How does the fourth and last factor for an investor
3 considering a stock investment in a utility affect the
4 decision?

5 A. The last factor, restrictions on business lines, is
6 less quantifiable because it represents the
7 opportunities foregone by the investor. Restrictions
8 on investments in generation in New York, and the
9 punitive indirect regulation of affiliate company
10 capitalization, reduce the value of the Company to its
11 owner, but in ways that are difficult to quantify
12 explicitly.

13 Q. Besides trends in regulation, what are the financial
14 metrics that impact the decisions of equity investors?

15 A. Equity investors are concerned with the two sources of
16 potential return, dividends and earnings per share
17 growth, that they can expect the Company to provide.

18 Q. How do dividends on Con Edison compare with dividends
19 on the average stock?

20 A. At current price levels, Con Edison's dividend yield
21 is approximately 5.9%, versus 3.1% for the S&P 500.

1 Q. How does the expected earnings per share growth of Con
2 Edison compare to the average stock?

3 A. According to First Call, estimates for Con Edison's
4 long-term earnings per share growth are 2.7% per year.
5 Estimates for the S&P 500's earnings per share growth
6 are 11.3% per year. Dividend yield plus long-term
7 growth are 8.6% for Con Edison and 14.4% for the S&P
8 500.

9 Q. Using the sum of these two estimates as a simple proxy
10 for expected total return, how does Con Edison stack
11 up?

12 A. It has a very high dividend yield, made higher by the
13 fall in price from its recent levels, which does not
14 compensate for its anemic potential for growth in
15 earnings per share.

16 Q. What are the implications of the high dividend yield
17 and low expected growth rate for CEI stock?

18 A. High current income stocks are a niche investment, a
19 sort of bond substitute for investors, rather than an
20 equity. The most likely holders are individual
21 retirees and mutual and investment funds that appeal

1 to retirement-oriented investors.

2 Q. Are there risks associated with being a niche
3 investment?

4 A. Yes. While at present investors are relatively
5 interested in this very defensive investment profile,
6 that interest will reduce dramatically when the equity
7 markets begin to stabilize and investors see much more
8 attractive investment opportunities elsewhere.. In
9 addition, the dependence on dividend-oriented
10 investors is risky in a period when the dividend tax
11 relief is likely to expire in 2010. Wall Street
12 analysts have estimated a 10% increase in the cost of
13 equity for utilities like Con Edison upon the sunset
14 of the dividend tax relief now in place. Today, Con
15 Edison's stock is not competitive on a total return
16 basis and equity analysts do not recommend investment.
17 Despite the near-freefall in the stock market,
18 according to a recent (November 21, 2008) survey in
19 Bloomberg Con Edison still ranks among the worst like
20 stocks in the economy: 29th lowest of all stocks in the
21 S&P 500 in terms of average recommendation among

1 securities analysts. It is unclear how much longer
2 investor's will accept low long-term returns for the
3 sake of higher current income. When the stock market
4 regains its balance, the only way to sell a dividend-
5 oriented stock with no real earnings growth will be to
6 increase the yield through a lower price.

7 Q. Con Edison will have to sell significant amounts of
8 equity in the next few years. What is the receptivity
9 of the current difficult equity market for new
10 capital?

11 A. It is difficult to judge what appetite there may be
12 for new equity capital. Most of the equity issued in
13 the past few months has been issued out of desperation
14 by financial institutions. Only three utilities have
15 issued equity since the stock market started to sell
16 off in mid-September. Otter Tail Power, which issued
17 \$155 million later in September, saw its stock price
18 drop almost 25% between the time it announced the
19 offering and the time it issued. PEPCO Holdings issued
20 \$231 million of equity on November 5. In spite of the
21 fact that the issue was reduced in size from 17

1 million to 14.5 million shares, the stock price
2 dropped 19% from announcement to issue and the
3 issuance took place below book value, destroying value
4 for existing shareholders. Finally, on November 18
5 Central Vermont issued \$21 million of equity at a
6 price that was 13% below the price before the
7 announcement.

8
9 With significant capital expenditures undertaken in
10 the electric utility industry and just \$755 million of
11 equity issued so far this year, I expect Con Edison to
12 face significant competition for investor dollars
13 during the rate year. Given the overall decline in the
14 equity markets, financial experts have begun to point
15 out the potential for significant rewards to investors
16 from buying stock in high-quality companies at reduced
17 prices. Thus any new equity issuance will have to be
18 priced to compete with the bargains available in the
19 market. As an example of this type of analysis, Morgan
20 Stanley's equity research team recently published a
21 report entitled "Quantum of Solace—Stocks to Own Now"

1 [Abhijit Chakrabortti and Jason Todd, October 15,
2 2008]. In that report they proposed a model that would
3 set share price targets based on an adjusted market
4 earnings multiple and a discount factor for 2008
5 estimated earnings. At their utility earnings multiple
6 of 12x 2008 earnings, their 20% earnings discount
7 factor for utility companies and the median analysts'
8 estimate for Cons Edison of \$3.05 per share, this
9 analyst would value Cons Edison common stock at \$29.28
10 per share: or a little less than 85% of book value,
11 and 27% below November 24th's closing price of \$40.18
12 per share.

13 Besides the likely decline in equity price faced by
14 the Company when it issues shares, it is probable in
15 this market that the methodology we have used in
16 selling the last two equity issues, a so-called
17 "bought deal" in which underwriters bid for the stock,
18 will no longer find takers amongst the much more risk
19 averse banks and investment banks. This will lead to
20 higher underwriting costs.

21 As a final comment on equity cost, I would note that

1 Con Edison is not assured of access to the equity
2 markets today, and unless adequate financial terms are
3 reached in the present proceeding and others being
4 undertaken by the utility subsidiaries, may well be
5 unable to raise equity capital prospectively.

6 Q. Please comment on the Commission's use of the
7 discounted cash flow (DCF) model?

8 A. Valuation methods such as the DCF can be reasonable
9 (if imperfect) methods for determining expected
10 returns for investors when they apply market-derived
11 data to the value of the firm that captures the
12 accumulated benefits described above: the market value
13 of equity. The method and the application are then
14 internally consistent and reward the equity-holder for
15 what his or her stock investment is currently worth.
16 In contrast, the current New York Public Service
17 Commission practice of applying market-derived returns
18 to the much lower discounted book value per share
19 strips out the accumulation of improvements to the
20 business and its assets, and is neither consistent nor
21 correct. The Commission's application of the capital-

1 asset-pricing models suffers from similar flaws.

2 Q. Please continue.

3 A. Another way of assessing New York's treatment of
4 equity investors is to look at how the regulatory
5 process in New York is viewed by investors themselves.
6 The rating agencies represent the interests of fixed
7 income holders. In a previous section of my testimony
8 I have provided examples of how they view the
9 regulatory situation in New York.

10 On the equity side, I would like to highlight one
11 publication. Citibank, in its *Company Focus* -
12 *Consolidated Edison (ED)* (January 9, 2008 page 3)
13 said:

14 When looking at qualitative factors like
15 shareholder total return prospects, earned return
16 over cost of equity, regulatory risk, business
17 mix, balance sheet strength, and relative
18 strength of cash flow ED screens poorly vs. its
19 Defensive peer group.

20
21 Thus Con Edison's business risk position (regulatory
22 risk and business mix) is weak even relative to
23 companies similarly subject to profit regulation. In
24 the face of this perceived weakness, the Commission's
25 pursuit of rates of return and other policies that

1 weaken the appeal of the Company to the very investors
2 that customers will need to provide the capital
3 necessary to provide them reliable service continues
4 at our collective peril.

5 Q. What about comparability to other investments?

6 A. Numerically, Con Edison trades at a price-to-book
7 multiple of roughly 1.1 compared to the industry
8 average ratio of about 1.4. This is such a
9 significant difference that I believe the Commission's
10 authorized returns fall short of even the narrowest
11 definition of comparability.

12

13 Q. Does this conclude your testimony?

14 A. Yes, it does.

15

16

17

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
JANE J. QUIN
NYPSC CASE NO. _____

1 Q. Please state your name and business address.

2 A. Jane J. Quin, 390 W. Route 59, Spring Valley, New York 10977.

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

4 A. I am Director – Customer Energy Services for Orange and Rockland Utilities,
5 Inc. (“O&R”, “Orange and Rockland” or the “Company”).

6 Q. Please briefly outline your educational and business experience.

7 A. I received a Bachelor of Arts degree from the University of Michigan in 1977
8 and a Juris Doctorate degree from the University of Tulsa, College of Law, in
9 1985. My first employment was as an associate with the energy group of the
10 Hall, Estill law firm in Tulsa, Oklahoma in 1985. I was subsequently
11 employed as a senior associate with the energy group of the Baker & Botts law
12 firm in Washington, D.C. from 1989 to 1993. I joined Orange and Rockland
13 in 1994 as Attorney responsible for the Company’s gas regulatory matters. In
14 1999, I accepted a position with the Law Department at Consolidated Edison
15 Company of New York, Inc. (“Con Edison”) after the merger of Orange and
16 Rockland and Con Edison, Inc. I represented both Orange and Rockland and
17 Con Edison in gas and electric regulatory matters, including retail access
18 issues, as Senior Attorney and Associate Counsel. In May 2005, I accepted
19 the position of Director – Retail Access and Energy Services for Orange and
20 Rockland. The name of the group was subsequently changed to Customer

1 Energy Services. I have participated in the preparation of testimony and
2 exhibits in rate cases and regulatory proceedings in New York, New Jersey,
3 and Pennsylvania and at the Federal Regulatory Energy Commission. I have
4 previously testified before the New York State Public Service Commission
5 ("NYPSC" or "Commission") in Case No. 05-G-1494, Case No. 06-E-1433
6 and Case No. 07-E-0949; before the New Jersey Board of Public Utilities in
7 BPU Docket No. EO08050326, BPU Docket No. EO08090703, and BPU
8 Docket No. EO08090702; and before the Pennsylvania Public Utility
9 Commission in Docket No. P-00062205.

10 **SUMMARY OF TESTIMONY**

11 Q. What is the scope of your testimony in this proceeding?

12 A. In my testimony, I will discuss the following topics:

- 13 • The current status of the Company's gas retail choice program and the
14 Company's plans to comply with the New York State Public Service
15 Commission's ("NYPSC") Order Determining Future of Retail Access
16 Programs issued on October 27, 2008, in Case 07-M-0458;
- 17 • Proposed tariff provisions designed to increase the efficiency of the
18 Company's gas transportation program;
- 19 • The continuation of the Company's low-income program for gas customers;
20 and
- 21 • The Company's gas efficiency plans.

22 **Retail Choice Program**

23 Q. Please describe the current status of the Company's retail choice program.

1 A. Since 1986, O&R's largest interruptible service commercial and industrial
2 customers have been able to choose a competitive provider of gas supply. As
3 of October 31, 2008, 90 customers take interruptible delivery service from the
4 Company under Service Classification No. 8, bringing approximately
5 4,863,381 Mcf/year to the O&R system. Currently, the Company has only two
6 remaining interruptible sales customers.

7 Q. Please discuss the Company's retail choice program for its firm customers.

8 A. Pursuant to NYPSC Case 93-G-0932, the Company began in October 1996 to
9 offer its firm delivery service customers a choice of suppliers under Service
10 Classification No. 6. As of October 31, 2008, 40% of O&R's firm service
11 customers (*i.e.*, 51,099 customers) have chosen service from among the 18 gas
12 marketers participating in the Company's retail choice program. Of these
13 customers, 90% (*i.e.*, 45,761 customers) are residential. The annual load for
14 retail access customers is 9.9 Bcf, representing 51% of the Company's total
15 firm throughput.

16 Q. Has the Company been actively promoting its retail access program?

17 A. Yes. Pursuant to the NYPSC's Statement of Policy on Further Steps Toward
18 Competition in Retail Energy Markets ("Policy Statement"), issued on August
19 25, 2004 in Case 00-M-0504, the Company has actively promoted the
20 competitive retail energy market in its service territory. The Company filed its
21 Retail Access Plan in response to the Policy Statement on January 27, 2005,
22 and proposed to continue to educate customers on the fundamentals of
23 competitive energy markets, such as how costs of supply and delivery are

1 treated separately and that, if they switch to an energy supplier, O&R will
2 continue as their energy delivery company and respond to all emergencies.

3 O&R's Retail Access Plan also provided that it would inform customers about
4 individual energy services companies ("ESCOs"), focusing specifically on
5 ESCOs' names, business descriptions and the unique programs that they offer.

6 Q. What actions has the Company taken to promote retail access?

7 A. The Company promotes retail access through its PowerSwitch and eBids
8 programs and through customer outreach and education. All electric and gas
9 ESCOs participating in O&R's retail access program are eligible to participate
10 in both the PowerSwitch and eBids programs. O&R's ESCO Referral
11 Program, now called PowerSwitch, was established prior to the Commission's
12 December 22, 2005, Order in Case 05-M-0858, which established state-wide
13 standards for such programs. In compliance with the Commission's
14 December 22, 2005, Order, the Company submitted an "ESCO Referral
15 Program Proposal" on February 17, 2006. That Proposal was approved by the
16 Commission on April 19, 2006, in its Order Adopting O&R's Plan for an
17 ESCO Referral Program and the terms and conditions of O&R's current
18 PowerSwitch program were established pursuant that Plan.

19 Q. Please describe O&R's PowerSwitch program.

20 A. Under PowerSwitch, residential and small to medium commercial and
21 industrial ("C&I") customers may enroll with an ESCO for their supply by
22 contacting the Company at its toll-free customer service telephone number,
23 through the customer service voice response unit ("VRU"), on the Company's

1 website, or through enrollment cards included as bill inserts. Customers
2 agreeing to participate in retail access either may choose their ESCO or,
3 absent such choice, O&R assigns them to an ESCO. Customer assignments
4 are made by rotating through the list of participating ESCOs. If a customer
5 wants to have both its electric and gas supply service assigned to an ESCO
6 through PowerSwitch, a single ESCO that provides both services will be
7 assigned. This procedure is consistent with the theme of the Company's
8 PowerSwitch program, which is to make the process as simple and as easy to
9 understand as possible for the benefit of the customer. Approximately 56% of
10 participating customers now choose their own ESCO. ESCOs must accept all
11 customers who specifically select them or who are assigned to them by O&R
12 through the PowerSwitch program. ESCOs must provide each customer with
13 a 7% savings from the O&R gas commodity cost for a period of a minimum of
14 two consecutive billing periods ("Introductory Period"). All accounts enrolled
15 through the program are billed by O&R utilizing the O&R Single
16 Consolidated Bill option under which O&R purchases the ESCOs' receivables
17 for the Introductory Period. Continued service beyond the Introductory Period
18 is established by the terms and conditions of service established by the
19 contract provided to the customer by the ESCO for the Introductory and Post-
20 Introductory period. Customers are free to choose another ESCO or return to
21 O&R full service at any time. During Rate Year One of its current gas rate
22 plan (*i.e.*, year ending October 31, 2007) ("Rate Year One"), O&R had 723
23 enrollments through PowerSwitch, 284 of which were gas enrollments.

1 During Rate Year Two (*i.e.*, year ending October 31, 2008) ("Rate Year
2 Two"), the Company had 707 enrollments, 278 of which were gas
3 enrollments.

4 Q. Please describe the eBids Program.

5 A. O&R launched its eBids Program in late 2004 as a means, through internet
6 access to O&R's website, by which O&R's customers anonymously can seek
7 price proposals directly from ESCOs. The customer's usage information is
8 provided to the participating ESCOs, who then electronically submit price
9 proposals on the customer's energy needs. The customer is under no
10 obligation to accept any of the proposals. Customers can accept an ESCO's
11 proposal by contacting the ESCO directly or releasing their contact
12 information to the ESCO for follow-up from the ESCO. Since its
13 implementation, approximately 14,800 customers have used eBids. During
14 Rate Year One of its current gas rate plan, 2,415 customers used eBids and
15 during Rate Year Two, 3,288 customers used eBids.

16 Q. Has the Company taken any other steps to facilitate retail access in its service
17 territory?

18 A. Yes. Pursuant to the Commission's Order Establishing Rate and Terms of
19 Three-Year Rate Plan issued October 20, 2006, in Case 05-G-1494 ("2006
20 Rate Order"), the Company is allocated up to \$300,000 for each rate year of its
21 current three-year rate plan for spending under its Retail Access Promotion
22 and Customer Outreach and Education Program ("RA Outreach Program").
23 In addition to its PowerSwitch and eBids programs, under the RA Outreach

1 Program, the Company continues to engage in extensive outreach and
2 education efforts to inform customers of their option to choose natural gas
3 suppliers other than O&R and to explain how retail choice works. During
4 Rate Years One and Two, the Company conducted a "Back to Basics"
5 outreach effort in which it emphasized through bill inserts and print
6 advertising certain retail choice fundamentals, such as: (i) O&R continues to
7 deliver energy reliably for all customers, including retail choice customers; (ii)
8 O&R provides the same high quality customer service for all customers,
9 including retail choice customers; (iii) the Company provides certain tools,
10 such as eBids, PowerSwitch and its ESCO catalog, to help its customers shop
11 for energy; and (iv) O&R supports retail competition. These bill inserts and
12 advertisements also reassured customers that the Company will continue to
13 supply its customers with energy, even if their suppliers fail to do so, and that
14 the Company continues to respond to all electric outages and gas emergencies
15 for its customers. Representatives of the Customer Energy Services
16 Department also participated in numerous events throughout Rate Year One
17 and Rate Year Two which served as opportunities to educate the Company's
18 customers about retail choice, including the Rockland and Orange County
19 Home Shows, business expos sponsored by the Rockland Business
20 Association and dozens of meetings of community and business groups
21 throughout the service territory. The Company spent \$107,762 under its RA
22 Outreach Program in Year One and \$99,902 in Year Two.

23 Q. Has the Company conducted any surveys related to retail choice?

1 A. Yes. Orange and Rockland has conducted three surveys related to retail
2 choice during Rate Year One and Rate Year Two. In Rate Year One, the
3 Company surveyed its eBids users to assess their level of satisfaction with the
4 program. As a result of the survey, the Company followed up with the ESCOs
5 participating in the program to inform them that price proposals must be
6 definitive and timely, as these were two areas of dissatisfaction expressed by
7 the customers surveyed. In addition, as part of the Customer Assessment
8 Survey ("CAS") conducted each fall, during October 2007 and October 2008,
9 the Company surveyed its customers on their awareness and understanding of
10 retail choice. Overall, the surveys demonstrated that customers are aware of
11 retail choice in the Company's service territory and understand the
12 fundamentals of the Company's program. Based on the most recent survey
13 results, about 70% of O&R's customers are aware of deregulation and of those
14 aware, over 80% demonstrated a high level of understanding of retail choice.
15 The retail choice customers also appear to be relatively satisfied with the
16 performance of their ESCOs. One survey question asked retail choice
17 customers to rate the level of their satisfaction with their ESCO. The ratings
18 ranged from "1" for "very dissatisfied" to "5" for "very satisfied." For gas
19 retail access customers in Rate Year One, 85% of the customers surveyed
20 rated their level of satisfaction as 3 or above and in Rate Year Two the rate
21 increased to 87%.

22 Q. Does the Company propose to continue its Retail Access Outreach Plan once
23 its current gas rate plan expires?

1 A. On October 27, 2008, the Commission issued its Order Determining Future of
2 Retail Access Programs in Case 07-M-0458 ("October 2008 Order"). The
3 October 2008 Order (p. 3) found that retail access markets are sufficiently
4 well-established in New York to warrant discontinuance or modification of
5 some retail access policies and practices. The October 2008 Order provides (p.
6 2) that retail access programs that are integral to the structure of the
7 competitive markets will be continued and that it also remains appropriate for
8 utilities to provide information on competitive markets to their customers
9 through utility outreach and education programs. According to the October
10 2008 Order (pp. 7-8), programs essential to maintaining a competitive market
11 structure, such as an Electronic Data Interchange ("EDI") platform, utility
12 consolidated billing and the purchase of accounts receivable ("POR"), should
13 continue with on-going costs funded by ESCOs through such mechanisms as
14 a discount rate applied by the utility to the ESCO's receivables. Consistent
15 with the October 2008 Order, O&R proposes to continue to provide an EDI
16 platform, consolidated billing and the POR.

17 Q. Does the Company propose any changes to its POR discount rate?

18 A. Yes. As a result of the current economic downturn and increasing
19 uncollectibles, the Company proposes to modify the calculation of the
20 uncollectible portion of the POR discount rate. Specifically, the uncollectible
21 component of the POR discount, which is to be reset annually effective
22 November 1, will be based on the Company's actual uncollectibles experience
23 applicable to all gas and electric POR-eligible customers for the twelve-month

1 period ended the previous June 30, as opposed to the current methodology of
2 using the thirty-six month period ended the previous June 30. This change
3 will allow, during these economically volatile times, for the POR discount
4 factor to reflect more accurately the scope of the Company's uncollectibles.
5 As is currently the practice, the risk factor shall continue to be reset annually
6 and shall be equal to 20% of the uncollectible rate. In addition, in order to
7 achieve consistency with the Company's practices for electric POR, a credit
8 and collections component will be added to the POR discount for gas ESCOs.
9 This component will be determined by dividing the Company's credit and
10 collection expenses attributable to retail access customers whose ESCOs
11 participate in the Company's POR program by estimated gas supply costs to
12 be billed on ESCOs' behalf, as further discussed in the testimony of Company
13 witness William Atzl.

14 Q. Does the Company plan on modifying any features of its retail access program
15 in response to the Commission's October 2008 Order?

16 A. The October 2008 Order, provides (p. 10) that "with the retail energy market
17 maturing, . . . it is no longer appropriate to spend ratepayer funds to promote
18 retail access. The obligation for funding promotional programs shall be
19 shifted to the ESCOs, who must assume the financial responsibility of
20 promoting their competitive offerings." Programs identified as primarily
21 promotional in nature include ESCO referral, market match, market expos and
22 energy fairs. For O&R, this would include its PowerSwitch program, which is
23 an ESCO referral program, and its eBids program, which is a market match

1 program. Because these programs are not currently ESCO funded,
2 modifications to both PowerSwitch and eBids must be made to comply with
3 the October 2008 Order.

4 Q. Does the Company plan to continue PowerSwitch and eBids?

5 A. Pursuant to the October 2008 Order (p. 10), "going forward, utilities are
6 authorized, but not required to continue market match programs, market expos
7 and energy fairs if ratepayers do not bear the cost of the programs." If
8 utilities choose to continue these programs, at ESCO expense, then utilities are
9 expected to obtain funding from the ESCOs for the programs, as well as input
10 from the ESCOs on the program's content and structure. According to the
11 October 2008 Order (p. 13), with regard to ESCO referral programs, utilities
12 are directed to continue existing programs, but such continuation is
13 conditioned on ESCO funding for the program. The Company's eBids
14 program has been in place since 2004. The costs associated with continuing
15 the program, which is web-based, are now limited to promotional costs, such
16 as occasional bill inserts to explain the how the program works, and a share of
17 the cost of maintaining the server that hosts the program. The Company's
18 ESCO referral program, PowerSwitch, has been in place since 1999. The
19 costs associated with continuing the program include: (a) promotional costs,
20 such as bill inserts; and (b) program administration costs, which include the
21 costs of enrolling PowerSwitch customers, calculating and inputting the
22 discounted price into the Company's billing system each month, and
23 monitoring the price for PowerSwitch customers to make sure that price

1 changes are not entered during the Introductory Period, all of which are
2 manual functions. A breakdown of these charges will be included in the
3 Company's proposal for ESCO funding of PowerSwitch, to be filed with the
4 Commission by December 11, 2008, in compliance with the October 2008
5 Order and will also be incorporated in my Rebuttal Testimony in this
6 proceeding. Although O&R is amenable to continuing these programs and
7 assessing ESCOs for these costs, the Company is: (i) uninformed as to
8 whether ESCOs are willing to fund the programs, including promotion costs,
9 given current enrollment rates; (ii) uncertain of the value of continuing
10 programs if adequate promotional funding is not provided; and (iii) unwilling
11 to continue to host programs for which it does not have promotional control.
12 These issues will have to be explored further in an ESCO collaborative in
13 order to determine the future of the PowerSwitch and eBids programs.

14 Q. What action does the Company plan on taking with regard to retail choice
15 outreach and education?

16 A. The October 2008 Order provides (p. 13) that "utilities are required to
17 continue to provide outreach and education information on the availability of
18 retail access. Expenditures on the dissemination of such objective information
19 would fall within the ambit of usual utility O&E budgets for customer
20 education purposes." The Company proposes to continue education and
21 outreach efforts, such as its "Back to Basics" campaign. O&R will
22 discontinue providing materials, such as bill inserts, in support of
23 PowerSwitch and eBids, based upon its understanding that such activities

1 would be considered promotional. The Company does propose to carry over
2 to this case \$300,000 of unexpended funds from its current RA Outreach
3 Program to be used for retail access outreach and education. These funds
4 would be added to the Company's usual outreach and education budget for use
5 in disseminating objective information on retail access. The Company would
6 budget \$100,000 per year for this activity, which approximates the Company's
7 current level of spending under its RA Outreach Program. These funds would
8 be used to educate customers on the key elements of retail choice, such as: (i)
9 informing customers that they have the option to choose natural gas suppliers
10 other than O&R; (ii) educating customers on how the costs of supply and
11 delivery are treated separately and on how these costs are represented on their
12 O&R bill; (iii) providing customers, in response to inquiries, with a list of
13 eligible ESCOs and their contact information; (iv) assuring customers that if
14 they switch suppliers, O&R will continue as their energy delivery company;
15 and (v) informing customers that in the event of an emergency, O&R will
16 continue to be responsible for service restoration and that system reliability,
17 safety and customer service are unimpaired by switching. Pursuant to the
18 October 2008 Order, the Company will collaborate, where appropriate, with
19 ESCOS on how best to provide useful information to its customers on the
20 retail market.

21 Q. Is the Company proposing to continue its annual retail choice awareness and
22 understanding survey?

1 A. No. The October 2008 Order provides that utilities are relieved of the
2 obligation to perform retail choice customer awareness surveys in the future.
3 Given the high levels of retail choice awareness in the Company's service
4 territory (71% of gas customers surveyed in 2008 were aware of natural gas
5 deregulation), the Company proposes to discontinue its retail choice
6 awareness and understanding service after Rate Year Three of its current gas
7 rate plan.

8 Q. Is the Company proposing a retail access incentive in this proceeding?

9 A. No. Pursuant to the requirements of the October 2008 Order (p. 14), the
10 Company will terminate its Retail Choice Customer Understanding Incentive
11 at the end of Rate Year Three of its current gas rate plan.

12 **Rollover Option**

13 Q. Do you propose any tariff changes related to retail access or gas transportation
14 services?

15 A. Yes, we propose a change to the balancing service options applicable to
16 Qualified Sellers under Service Classification No. 11 ("SC No. 11"), which
17 appear in both the "Balancing Service Option" section and the "Winter
18 Bundled Sales Service Option" section. Currently in SC No. 11, Qualified
19 Sellers have the option of settling their monthly imbalance volumes (*i.e.*, the
20 difference between the volume of gas delivered to the city gate (the
21 Aggregated Daily Contract Quantity or "ADCQ") and the volume of gas used
22 by their customers) through a Rollover Option or a Cash-Out Option. Under
23 the Cash-Out Option, the over-delivered volumes each month will be

1 purchased by the Company from the Qualified Seller and the under-delivered
2 volumes will be sold by the Company to the Qualified Seller at a production
3 area index price, plus the Company's adjusted weighted average cost of
4 transportation ("WACOT") for such month and fuel losses. Qualified Sellers
5 also have a Rollover Option for settling imbalances. Under the Rollover
6 Option, the monthly over- and under-deliveries are carried over into
7 succeeding months by adjusting the Qualified Seller's ADCQ on a going-
8 forward basis. As in its last gas base rate case, the Company is again
9 proposing to eliminate the Rollover Option from both the Balancing Service
10 Option section and the Winter Bundled Sales Service Option section of SC
11 No. 11.

12 Q. Why is the Company proposing to eliminate the Rollover Option?

13 A. The Rollover Option results in gas imbalances being reconciled through
14 delivered volumes up to three months after the fact. By the time all customer
15 bills are rendered for periods that include a portion of the calendar month in
16 which the over- or under-delivery occurred and the under- or over-delivery is
17 reflected in an adjusted ADCQ, three months have passed. In a volatile
18 market, the price of gas may have increased or decreased significantly over
19 those three months. As a result, there is a risk of a significant mismatch
20 between the value of the imbalance and the value of gas delivered to correct
21 imbalances for both the Qualified Sellers and for the Company's firm sales
22 customers, as reflected in the Gas Supply Charge. The Cash-Out Option
23 provides for a reimbursement mechanism on under- and over-deliveries that

1 reflects actual market prices at the time the under- or over- delivery occurred.

2 It is a more equitable and economically efficient means of balancing Qualified
3 Sellers' deliveries.

4 Q. Can you quantify the magnitude of the risk of under recovering gas costs
5 under the Company's Rollover Option for balancing?

6 A. While it is impossible to determine prospectively the maximum risk to either
7 the ESCOs or to the Company's firm sales customers in any year associated
8 with the continuation of the Rollover Option, O&R has examined how historic
9 price changes have impacted the rollover of imbalances in past years to
10 evaluate the level of risk created by a volatile gas market. See Exhibit ____ (G-
11 11). For instance, in 2006, collectively the ESCOs lost over \$1.5 million in
12 gas cost differentials between the incurrence of gas imbalances and the re-
13 delivery of volumes under the Rollover Option. More specifically, by the time
14 the ESCOs paid back the gas to the Company or the Company paid back the
15 gas to the ESCOs after the ESCOs incurred imbalances, the value of the gas
16 had changed by \$1.5 million. The greatest loss in a single month occurred in
17 March 2003, when ESCOs lost over \$1.1 million in gas cost differentials. The
18 pricing differential can work against the interests of the Company's firm sales
19 customers, as well. For instance, when ESCOs delivered gas to O&R in June
20 2003 to make up for imbalances incurred in March 2003, the value of gas had
21 dropped by over \$3.00 a dekatherm, thereby resulting in a gas cost differential
22 between the under-deliveries and the make up volumes of over \$800,000.
23 Although, on balance, over the years that the Company has had a Rollover

1 Option for ESCOs, the Company's customers have not been economically
2 harmed, past performance is not a guarantee of future results. In a volatile
3 market with colder or warmer than normal weather, the price risks could be
4 significant.

5 Q. Does the Company have any other reasons for proposing to eliminate the
6 Rollover Option?

7 A. Yes. Of increasing significance are the operational challenges created by the
8 continuation of the Rollover Option. Transportation volumes now make up
9 approximately 50% of the load on O&R's system. With this level of
10 transportation gas moving on the system on a monthly basis, it has become
11 increasingly difficult for the Company's Gas Control to manage the rollover
12 volumes, particularly during the shoulder months. For instance, in May 2007,
13 ESCOs owed close to 300,000 Dth of gas to the Company and in June 2007, a
14 summer month, the imbalance volume delivered to the Company was
15 approximately 230,000 Dth, representing over one-third of firm gas moving
16 on system that month. It is operationally challenging for the Company to
17 accommodate 300,000 Dths of additional gas supply during a shoulder or
18 summer month when gas usage is substantially reduced and parts of the
19 Company's system and the interstate pipeline systems interconnecting with the
20 Company may be down for routine maintenance. Under such circumstances,
21 the Company needs to alter its supply plans for the full service customers and
22 rely on assets such as storage to handle the extra deliveries. Unusually high

1 rollover volumes could cause the Company to exceed its storage injection
2 limitations.

3 Q. Does the Company propose an alternative to the Rollover Option?

4 A. The Company's tariff provides a Cash-Out Option (SC No. 11 at Leaf 153 and
5 154.1) that is a fair and equitable means of handling gas imbalances. Under
6 the Cash-Out Option, imbalances are reconciled each month at an index price
7 for the month in which the imbalance occurs, thereby eliminating the need for
8 Gas Control to manage carry over volumes throughout the year.

9 **Low-Income Program**

10 Q. Does the Company propose to continue its low-income program?

11 A. Yes. The Company proposes to continue its program whereby any gas
12 customer, who receives a grant under the Home Energy Assistance Program
13 ("HEAP"), will receive a monthly bill credit. Currently that credit is \$7.00 per
14 month. Actual experience under the program over Rate Years One and Two
15 has demonstrated that the current funding level of \$475,000 is in excess of the
16 current level needed to provide the monthly credit to all eligible customers,
17 which has been approximately \$400,000 per year. However, the State has
18 recently revised the requirements for HEAP, thereby expanding the class of
19 customers now eligible for grants under the Program. This expansion of
20 HEAP eligible customers and the deteriorating economic conditions will
21 likely cause an increase in the number of customers qualifying for benefits
22 under the Company's low-income program and increase the necessary funding
23 levels to the \$475,000 range. Finally, given the proposed increase in the first

1 block charges for delivery service, the Company is amenable to increasing the
2 amount of the low income credit and will confer with interested parties
3 regarding the appropriate amount of such an increase, which would also
4 require a corresponding adjustment to the Company's proposed revenue
5 increase.

6 **Gas Efficiency Programs**

7 Q. Is the Company proposing any gas efficiency programs as part of this
8 proceeding?

9 A. The Company is not proposing to implement gas efficiency programs in this
10 proceeding. However, it is requesting an additional staff position for purposes
11 of, among other activities, designing, administering and marketing future gas
12 efficiency efforts. On August 22, 2008, the Company submitted its Expedited
13 Residential Efficient Gas Equipment Program ("Fast Track Gas Program") in
14 accordance with the Commission's Order Establishing Energy Efficiency
15 Portfolio Standard and Approving Programs in Case 07-M-548 ("EEPS
16 Proceeding"). As required by the Commission's EEPS Order, the Company's
17 Fast Track Gas Program proposes to provide incentives to residential
18 customers to install high efficiency residential natural gas heating and water
19 heating equipment. The Program was proposed to begin in the fourth quarter
20 of 2008 and was designed to achieve 16,238 Mcf of savings through the end of
21 2011. In addition to the effort to begin gas efficiency programs in the State, a
22 working group has been convened as part of the EEPS Proceeding to establish
23 targets for a gas efficiency portfolio standard for New York.

1 Q. What is the status of the Company's Fast Track Gas Program filing?

2 A. The submission of comments on the Fast Track Gas Programs has been
3 delayed in the EEPS Proceeding in favor of expediting consideration of the
4 Fast Track Electric Programs.

5 Q. Given the delays occurring in the EEPS Proceeding, why is the Company
6 requesting an additional staff person for the purposes of designing,
7 administering and marketing gas efficiency programs?

8 A. Currently the Company has no staff person available to assist in the regulatory
9 process with respect to its Fast Track Gas Program, which it was required to
10 file in the EEPS Proceeding. Nor does the Company have a staff person to:
11 (1) prepare to implement the Fast Track Gas Program upon approval; (2) fully
12 participate in the development of a Gas Efficiency Portfolio proceeding in the
13 State; (3) begin the process of designing a more comprehensive portfolio of
14 gas efficiency programs addressing industry sectors other than residential
15 customers; and (4) otherwise assist in meeting the State's gas efficiency goals,
16 whether through programs designed and run by the Company or those
17 designed and run by the New York State Energy Research and Development
18 Authority ("NYSERDA"). Regardless of the nature of the Commission's
19 authorization of gas efficiency programs in the EEPS Proceeding, the
20 Company will need incremental labor to assist in promoting the State's and
21 the Company's gas efficiency goals. Activities for the new staff position will
22 include participation in the regulatory process related to establishing gas
23 efficiency programs in the State; assisting in the start-up of such programs;

1 providing support to programs whether administered by the Company or
2 NYSERDA; overseeing the accounting functions for the recovery and
3 remittance of the new Gas System Benefits Charge ("SBC") funds; and
4 engaging in customer outreach and education in support of the State's gas
5 efficiency efforts. Because these activities may involve assistance to the
6 Company, NYSERDA and other efficiency administrators, as appropriate, and
7 may not be directly program-related, this base level of gas efficiency activities
8 should be recovered through base rates.

9 Q. What is the cost of this new staff position?

10 A. The Company anticipates that the expense associated with this additional staff
11 position will be approximately \$90,000.

12 Q. Does this conclude your testimony?

13 A. Yes, it does.

14

ORANGE AND ROCKLAND UTILITIES, INC.
GAS RATE PANEL
DIRECT TESTIMONY

NYPSC CASE No. _____

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

2 A. William Atzl, Yan Flishenbaum and Ricky Joe, 4 Irving Place, New York, New York
3 10003.

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

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

GAS RATE PANEL

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

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

16 **(Joe)** I am a Project Manager in the Rate Engineering Department. In 1993, I
17 graduated from Rutgers College, New Brunswick, New Jersey with a Bachelor of Arts
18 degree in Economics. In 2001, I graduated from the Rutgers Graduate School of
19 Management with a Master in Business Administration degree in Finance. I joined
20 Con Edison in 2004 as a Senior Analyst in the Rate Engineering Department and was
21 promoted to Senior Rate Analyst in 2006. I was promoted to my current position in
22 2008. Prior to joining Con Edison, I was employed by: the New Jersey Board of

GAS RATE PANEL

1 Public Utilities from 1993 to 2000, PricewaterhouseCoopers from 2000 to 2003, and
2 Amerada Hess Corporation from 2003 to 2004.

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; and the
6 development of unbundled costs associated with competitive services;
- 7 (2) the Company's proposal for revenue allocation and rate design; including the
8 impact of the proposed rate changes on customers' bills;
- 9 (3) the Company's proposal for a revenue decoupling mechanism ("RDM");
- 10 (4) the Company's proposal associated with lost and unaccounted for gas;
- 11 (5) other tariff changes;
- 12 (6) the Company's Gas Marginal Cost study; and
- 13 (7) the Company's proposed gas load research program.

14 Q. Please summarize your testimony.

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

- 16 • functionalizes and classifies various gas system costs to their operating functions;
- 17 • allocates these functionalized costs to the customer classes;
- 18 • shows the development of unbundled costs associated with competitive services;
- 19 • shows a total system rate-of-return of 6.38%, an SC No. 1 – Residential and Space
20 Heating rate-of-return of 4.38%, and an SC No. 2 - General Service rate-of-return
21 of 21.53%;
- 22 • demonstrates each ECOS study class's surplus or deficiency based on the
23 application of a $\pm 10\%$ tolerance band around the calculated total system rate-of-
24 return; and

GAS RATE PANEL

- presents the development of unbundled functional costs for competitive services pursuant to the NYPSC's Statement of Policy on Unbundling and Order Directing Tariff Filings, issued August 25, 2004, in Case 00-M-0504 ("Unbundling Policy Statement").

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

This section also describes customer bill impacts at various consumption levels.

Third, the RDM section describes the Company's proposal to implement an RDM.

Fourth, the Lost and Unaccounted For Gas section describes the Company's proposal for changes to its incentive/penalty mechanism for lost and unaccounted for gas.

Fifth, the Other Tariff Changes section discusses the Company's proposals relating to interruptible transportation service, the POR discount, the Transition Adjustment for Competitive Services ("Transition Adjustment"), the Sharing of Benefits Mechanism, recovery of gas in storage working capital costs, the SC No. 11 Rollover Option, and the weather normalization adjustment ("WNA") mechanism.

Sixth, the Marginal Cost Study section of the testimony presents the Marginal Cost Study, which compares the existing delivery revenues with the marginal costs associated with delivery service. The study indicates that, the marginal cost of transmission and distribution exceeds the existing delivery revenues.

Seventh, the testimony presents the Company's proposed Gas Load Research Program.

Q. Is the Panel sponsoring any exhibits?

GAS RATE PANEL

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

2 (1) Exhibit G-13, Schedules 1-2 – Rate Design;

3 (2) Exhibit G-14 – Embedded Cost of Service Study; and Unbundled Cost

4 Components, Schedules 1-3; and

5 (3) Exhibit G-14, Schedule 4 – Marginal Cost Analysis.

6

7 **EMBEDDED COST-OF-SERVICE STUDY AND UNBUNDLED COST**

8 **COMPONENTS**

9

10 Q. Please begin with your presentation of the ECOS study.

11 A. The study to which you refer is contained in a document entitled “Orange and
12 Rockland Utilities, Inc. - Cost of Service Study – Gas Department - Year 2007, Rates
13 Effective November 1, 2008” Exhibit G-14, Schedule 1.

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

15 A. It covers Orange and Rockland’s gas operations for the calendar year 2007.

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

17 A. Gas revenues reflect rates effective November 1, 2008, excluding the Gas Supply
18 Charge (“GSC”), Monthly Gas Adjustments (“MGA”) and Interruptible Sales. Also
19 included are the Merchant Function Charge (“MFC”) revenues associated with
20 commodity procurement and credit and collections, as well as Billing and Payment
21 Processing revenues. The revenues associated with the uncollectible component of the
22 MFC and corresponding expenses have been excluded from the study. Firm
23 Transportation Customers have been priced with Firm Sales Customers in their
24 otherwise applicable classes.

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

GAS RATE PANEL

1 A. The ECOS study analyzes Orange and Rockland's two firm sales classes: SC No. 1 –
2 Residential and Space Heating; and SC No. 2 - General Service and Orange and
3 Rockland's firm transportation class: SC No. 6 – Firm Transportation. A description
4 of the type of customers served under each service classification is set forth on Page 12
5 of the ECOS explanatory notes. Since, for the purposes of the ECOS study and rate
6 design, we combine firm transportation classes with their otherwise applicable firm
7 sales service classes, SC No. 1 shall include SC No. 1 and SC No. 6 Rate Schedule IA.
8 SC No. 2 shall include SC No. 2 and SC No. 6 Rate Schedules IB and II.

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

10 A. The results of the ECOS study are expressed as Total Company ("total system") and
11 class-by-class rates of return.

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

13 A. The total system rate of return shown on Table 1, Page 1, Column (1), Line 17 of the
14 ECOS study is 6.38%.

15 Q. What are the class rates of return shown in the ECOS study, Exhibit G-14, Schedule 1?

16 A. The following class rates of return are shown on Table 1, Page 1, Line 17 of the ECOS
17 study:

18 SC No. 1: 4.38%

19 SC No. 2: 21.53%

20 Q. Has the NYPSC historically employed "tolerance bands" around the system rate of
21 return in developing class revenue responsibilities?

22 A. Yes. Based on past practice, class revenue responsibility has been measured with
23 respect to a $\pm 10\%$ tolerance band around the total system average rate of return.
24 Classes would not be considered "surplus" or "deficient" if the class ECOS rate of
25 return falls within this band. Classes that fall outside this range would be either
26 surplus or deficient by the amount necessary to bring the realized return to the upper or
27 lower band. We propose to continue this practice in this case.

GAS RATE PANEL

1 Q. Based on the application of a $\pm 10\%$ tolerance band around the calculated total system
2 rate of return of 6.38%, what are the ECOS study class surpluses and deficiencies?

3 A. SC No. 1 shows a revenue deficiency of approximately \$5.4 million. SC No. 2 shows
4 a revenue surplus of approximately \$7.5 million.

5 Q. What is the significance, for example, of the SC No. 1 class deficiency?

6 A. The deficiency is the amount of revenue increase, at current rates, required to bring SC
7 No. 1's return to the lower level of the tolerance band around the system rate of return.

8 Q. Please describe what is shown on Table 1A, which is the last page of Exhibit G-14,
9 Schedule 1.

10 A. Due to the application of class tolerance bands, the total of the ECOS surplus and
11 deficiency is a net system surplus. In order that the ECOS study indications are
12 revenue neutral to the Company, Table 1A adjusts the surplus of the SC No. 2 class so
13 that the surplus and the deficiency net to zero. These adjusted surplus and deficiency
14 are used in revenue allocation as described later in this testimony.

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

16 A. Yes. Please refer to Table 6, Page 1, Line 14 of the ECOS study. The monthly
17 customer costs by class are as follows:

18 SC No. 1: \$44.91

19 SC No. 2: \$66.14

20 Q. What do customer costs include?

21 A. Customer costs include distribution customer component, services, meter and meter
22 installations, installations on customers' premises, receipts processing, printing &
23 mailing a bill, customer accounting, uncollectibles and customer service.

24 Q. Please discuss the methodology that the Company used in developing the ECOS study.

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

GAS RATE PANEL

1 distribution-demand/customer components (mains), distribution-services); 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 cost
5 categories to the more detailed categories used in the ECOS study. This breakdown is
6 required, for example, to differentiate distribution-demand related costs from
7 distribution-customer related costs. During the process of functionalization, all costs
8 are classified as being demand-related, commodity-related, and customer-related.
9 Demand-related costs are fixed costs created by the on-peak hourly loads placed on the
10 various components of the gas system. Commodity-related costs are variable costs
11 caused by the total quantities of gas delivered during the year. Customer-related costs
12 are fixed costs, which are caused by the presence of customers connected to the
13 system, regardless of their usage.

14 Q. Please describe the allocation step.

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

18 Q. Please explain the general organization of the ECOS study.

19 A. The ECOS study begins with explanatory notes detailing sources of data and methods
20 used in the preparation of the study followed by seven tables of cost data.

21 Q. Does the ECOS study present unbundled functional costs for competitive services as
22 set forth in the NYPSC's Unbundling Policy Statement?

23 A. Yes. The ECOS study separately identifies the following competitive functions:
24 merchant function, receipts processing, and printing and mailing a bill.

25 Q. What costs are included in the merchant function?

GAS RATE PANEL

1 A. The merchant function includes the costs associated with procuring commodity, including
2 an allocation of customer care-related activities, customer service-related activities, and
3 information resources (“IR”).

4 Q. What costs are included in the customer care and customer service-related activities that
5 were allocated to the merchant function?

6 A. The customer care allocation includes costs associated with the Company’s Call Center,
7 Service Center, and credit and collection activities. The customer service allocation
8 includes an assignment of education and outreach costs.

9 Q. How were these costs allocated to the merchant function?

10 A. Pursuant to the NYPSC’s Unbundling Policy Statement (p. 20), customer care and
11 customer service-related costs were allocated to the merchant function on the basis of
12 revenues, including commodity revenues.

13 Q. How were IR costs allocated to the merchant function?

14 A. Pursuant to the Unbundling Policy Statement (p. 24), IR costs were allocated on the basis
15 of revenues, including commodity revenues, with 50% of the resultant allocation included
16 in the merchant function.

17 Q. Have you further unbundled the merchant function for developing rate components for
18 competitive services?

19 A. Yes. The merchant function has been disaggregated into two unbundled rate components:
20 (1) Competitive Supply-Related costs – representing the costs associated with procuring
21 commodity, IR, and education and outreach. Only full service customers will pay for
22 these costs.

23 (2) Competitive Supply Collections-Related costs – representing the costs associated with
24 credit and collection. These costs will also be recovered from full service customers. The
25 costs for credit and collection services associated with the Purchase of Receivables
26 (“POR”) program have been identified separately and will be included in the POR
27 discount applicable to marketers serving firm transportation customers.

GAS RATE PANEL

1 Q. Have you prepared an exhibit showing the allocation of the Competitive Supply-Related
2 costs and the Competitive Supply Collections-Related costs to service classes?

3 A. Yes. Exhibit G-14, Schedule 2 shows the allocation of these unbundled cost components,
4 to service classes. They are presented as percentages of the revenue requirement used in
5 the ECOS. Separate percentages are shown for the residential and commercial customers
6 for use in the development of the MFC, as detailed below.

7 Q. How are these components allocated to the service classifications within the study?

8 A. One hundred percent of gas procurement activity costs and 25% of credit and collection,
9 IR, and education and outreach costs were allocated on a per Ccf basis. The remaining
10 75% of credit and collection, IR, and education and outreach costs were allocated on a per
11 customer basis.

12 Q. Why were the customer care-type costs, such as credit and collection, allocated
13 predominantly on the basis of number of customers, while the gas procurement activity
14 was allocated entirely on a volumetric (i.e., Ccf consumption) basis?

15 A. The Company followed basic cost causation principles and determined that customer
16 care-type activities are predominantly driven by the existence of customers on the
17 system, as opposed to their usage characteristics. On the other hand, the functional cost of
18 purchasing commodity is aligned with sales volumes. We also would note that this
19 allocation is consistent with the NYPSC's Order issued April 15, 2005 in Case No. 04-E-
20 0572 approving Con Edison's unbundled rates, and was subsequently employed in the last
21 O&R gas proceeding, Case 05-G-1494.

22 Q. Did you prepare an exhibit showing the unbundled costs for the receipts processing, and
23 printing and mailing a bill functions?

24 A. Yes, we prepared Exhibit G-14, Schedule 3.

25 Q. Please continue.

26 A. The receipts processing function and the printing and mailing a bill function consist of
27 the customer accounting expense of accepting customer payments and billing

GAS RATE PANEL

1 customers including both direct costs and an allocation for Call Center and Service
2 Center operations based on a detailed study of those activities. These functions were
3 allocated a share of credit and collection, education and outreach, and uncollectibles on
4 the basis of functional revenues. The unbundled average unit cost for receipts
5 processing is 48.26 cents per bill per month. The average unit cost for printing and
6 mailing a bill is 44.57 cents per bill per month. These two functions are combined to
7 yield 93 cents in unbundled costs associated with billing and payment processing. The
8 costs associated with billing and payment processing do not vary by service
9 classification and thus, the system-wide 93 cents in unbundled costs is applicable to all
10 service classifications.

11 REVENUE ALLOCATION AND RATE DESIGN

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

13 A. The proposed revenue increase of \$17,773,000, including applicable revenue taxes,
14 was provided by the Accounting Panel.

15 Q. Please describe the first step in allocating the increased base rate revenue among the
16 Company's service classifications.

17 A. First, we removed from the total incremental revenue requirement for the Rate Year the
18 amounts included for New York State Gross Receipts and Franchise Tax surcharge
19 revenues, Municipal Tax surcharge revenues and Metropolitan Transportation
20 Authority Business Tax Surcharge revenues.

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

GAS RATE PANEL

1 A. Rate Year base rate revenues at the current rate level for SC No. 1 and SC No. 2 were
2 realigned to eliminate the deficiency and surplus indications from Table 1A of the
3 ECOS study.

4 Q. Did you attempt to eliminate fully the deficiency and surplus indicated by the ECOS
5 study?

6 A. Before making final decisions on the elimination of the deficiency and surplus, we
7 realigned the Rate Year delivery revenues to reflect the ECOS deficiency and surplus
8 indications and then allocated the net delivery revenue increase among the SCs in
9 proportion to the relative contribution made by each class to the realigned total Rate
10 Year delivery revenues. We then reviewed, by class, the combined impact of
11 eliminating a deficiency or surplus and the impact of the delivery revenue increase.
12 We found that fully eliminating the deficiency and surplus, coupled with the delivery
13 revenue increase, would result in a very large revenue impact for SC No. 1 as
14 compared with SC No. 2. Therefore, we have eliminated one-third of the deficiency
15 and surplus. This is accomplished by adding \$1,784,875 to SC No. 1 revenues and
16 subtracting \$1,784,875 from SC No. 2 revenues. This will move the classes in the
17 direction of more closely matching costs and revenues while limiting the customer bill
18 impacts associated with the changes. In the event the multi-year rate plan proposed by
19 the Accounting Panel is approved, we intend to further reduce any deficiency and
20 surplus in the additional rate years.

21 Q. Please continue.

22 A. We next determined what portions of the delivery rate increase would be attributable to
23 changes in the MFC fixed components, that is the MFC procurement and credit and

GAS RATE PANEL

1 collections components. As we discussed previously, Exhibit G-14, Schedule 2
2 presents these components as percentages of delivery revenue. Based on the increased
3 level of proposed delivery revenue, we computed a revised level of revenue for both
4 the procurement and credit and collections functions. We then subtracted the change in
5 these amounts from the delivery revenue requirement for each class to determine the
6 non-competitive delivery revenue requirement for each class.

7 Q. Did you restate the Rate Year non-competitive delivery revenue increases, as
8 determined above, on a historical period basis?

9 A. Yes. We restated the Rate Year non-competitive delivery revenue increases by service
10 classification on the basis of the twelve months ended October 31, 2008, *i.e.*, the
11 historical period for which detailed billing data are available.

12 Q. Please describe how you developed the non-competitive delivery revenue increases for
13 the historical period.

14 A. After adjusting for changes in revenues attributable to the MFC fixed components, as
15 described above, we applied to the resulting Rate Year incremental non-competitive
16 delivery revenue requirement for each class, ratios of the non-competitive delivery
17 revenues for the Rate Year and for the historical period priced at the rates effective
18 November 1, 2008. This resulted in an incremental base delivery revenue requirement
19 for the historic period of \$17,835,050.

20 Q. Please describe the intra-class gas rate design that produced the proposed delivery
21 service rates shown on Exhibit G-13, Schedule 1?

22 A. The SC No. 1 and SC No. 2 non-competitive delivery revenue requirements for the
23 historic period were applied in a two-step process.

GAS RATE PANEL

1 Q. Please describe the first step of the rate design process.

2 A. The first step in the rate design process is to increase the first block charge (the charge
3 for the first 3 Ccf or less) for Service Classification Nos. 1 and 2 and Service
4 Classification No. 6 Rate Schedules IA and IB to a level that better reflects the
5 Company's cost to provide service. These current charges are \$14.00 per month for
6 SC No. 1 and SC No. 6 Rate Schedule IA and \$21.00 per month for SC No. 2 and SC
7 No. 6 Rate Schedules IB. Our ECOS shows an embedded customer cost of \$44.91 per
8 month for residential and small non-residential heating customers and \$66.14 for
9 general service non-residential customers. Although in Case No. 05-G-1494 progress
10 was made in moving the Company's first block charge closer to the cost of service,
11 these charges remain far from the embedded customer costs of \$44.91 to \$66.14 per
12 month.

13 Given the disparity between costs and rates, we propose to increase the first block
14 charges for SC Nos. 1 and 2 and SC No. 6 Rate Schedules IA and IB by 1.5 times the
15 overall delivery revenue increase percentage. This results in an increase in the first
16 block charge for SC No. 1 and SC No. 6, Rate Schedule IA residential customers from
17 \$14.00 to \$18.22 per month and an increase in the first block charge for SC No. 2 and
18 SC No. 6, Rate Schedule IB non-residential customers from \$21.00 to \$27.33 per
19 month. These increases more closely match the first block charges with their
20 corresponding costs of service while limiting the rate impacts of the changes.

21 Q. Do you propose any change in the first block charge (the charge for the first 100 Ccf or
22 less) for SC No. 6 Rate Schedule II customers?

GAS RATE PANEL

1 A. Yes. We propose to increase this charge by the proposed percentage increase in
2 overall delivery revenues, thereby increasing this charge from \$172.13 to \$206.70 per
3 month.

4 Q. What is the second step in the rate design process?

5 A. Within each class, the remaining incremental revenue increase, after adjusting for
6 increases in the first block charges, was applied to the per Ccf charges on an equal
7 percentage basis.

8 Q. Have you increased the gas rates for O&R's distributed generation ("DG") customers?

9 A. Yes. We propose to increase the Rider B per Ccf delivery service rates to reflect the
10 percentage increases in per Ccf delivery service revenues proposed for SC No. 2, the
11 otherwise applicable non-DG class. Specifically, we propose to increase the "Usage
12 Charge" for gas usage above the first 3 Ccf each month as set forth under Rider B Rate
13 Schedule I - Rate IA, Rate IB, Rate IC, and Rate ID, and Rate Schedule II of the
14 "Delivery Charges" of Rider B. The "Contract Demand Charge" applicable to
15 customers under Rate Schedule II has also been increased by this percentage. The
16 initial block charge, which includes the first 3 Ccf of gas, has been increased by the
17 overall delivery revenue percentage increase for the SC No. 2 class.

18 We also propose to increase the Rider C per Ccf delivery service rates to reflect the
19 percentage increases in per Ccf delivery service revenues proposed for SC No. 1, the
20 otherwise applicable non-DG class. Specifically, we propose to increase the "Usage
21 Charge" for gas usage over 3 Ccf each month as set forth under the "Delivery Charge"
22 of Rider C. The initial block charge, which includes the first 3 Ccf of gas, has been
23 increased by the overall delivery revenue percentage increase for the SC No. 1 class.

GAS RATE PANEL

1 Q. Have you changed the charge for billing and payment processing?

2 A. No. In Case No. 05-G-1494, we established a billing and payment processing charge
3 of 62 cents per bill effective November 1, 2006. This charge was later increased to
4 \$1.02 per bill in Case No. 07-E-0949, the Company's last electric rate case, effective
5 August 1, 2008. As noted previously, we have determined an unbundled cost of 93
6 cents per bill for billing and payment processing. We are not proposing a change in the
7 billing and payment charge however, because the 9 cents per bill difference between
8 the billing and payment processing cost and the current charge does not justify the
9 customer confusion that would result from yet another change.

10 Q. Are you proposing a special rate for participants in the CNG pilot program proposed by
11 Company witness Diloreto?

12 A. Not at this time. Once the Company gains some experience with this program,
13 including some indication as to whether the incentive proposed by Mr. Diloreto is
14 adequate to encourage participation, we can evaluate whether or not a special rate is
15 warranted.

16 Q. Would you please describe Schedule 1 of Exhibit G-13?

17 A. Yes. Schedule 1 shows for Service Classification Nos. 1, 2, and 6, and Riders B and C,
18 the rates and charges effective November 1, 2008 and the proposed rates and charges.

19 Q. Would you please describe Schedule 2 of Exhibit G-13?

20 A. Yes. Schedule 2 shows the effects that the proposed rates will have on bills to firm
21 customers at various levels of consumption. Please note that the bills for firm
22 transportation customers include a gas supply cost comparable to that included in the
23 bills of full service customers.

GAS RATE PANEL

REVENUE DECOUPLING MECHANISM

Q. Is the Company proposing an RDM?

A. Yes, the Company is proposing an RDM based on a delivery revenue per class methodology for customer classes that are included in the RDM. This methodology is similar to the RDM methodology adopted by the NYPSC for the Company's electric operations in Case No. 07-E-0949. The RDM has been added to the Company's gas tariff as General Information Section No. 24. For purposes of applying the RDM, the Company's firm customer classes have been organized into two groups. Those customer classes that are included in the RDM, and those excluded from the RDM are as follows.

Customer Classes Included in the RDM

Group A Service Classification No. 1 and 6 Residential Customers

Group B Service Classification No. 1, 2 and 6 Non-Residential Customers

Customer Classes Excluded from the RDM

Rider B Gas Rates for Commercial and Industrial Distributed Generation Facilities

Rider C Gas Rates for Residential Distributed Generation Facilities

Under the RDM, actual delivery revenue is compared, on a monthly basis, with a delivery revenue target for each service classification group.

Q. How is Actual Delivery Revenue defined?

A. Actual delivery revenue, determined for each service classification group on a monthly basis, will be calculated as the sum of: a) total revenue derived from non-competitive delivery charges, as defined in Service Classification Nos. 1 and 2; b) transportation charges as defined in Service Classification No. 6; and c) revenues derived from the

GAS RATE PANEL

1 weather normalization adjustment. Actual delivery revenues will not include revenues
2 derived from the RDM Adjustment described below.

3 Q. How have the Delivery Revenue Targets been established?

4 A. The Delivery Revenue Targets were established by the Forecasting Panel and the
5 development of Delivery Revenue Targets is described in the Forecasting Panel's
6 testimony. Delivery revenue targets would have to be adjusted to reflect any delivery
7 rate changes that occur during a rate plan. In addition, adjustments to the delivery
8 revenue targets may be necessary if new legislation or regulation results in a change in
9 delivery revenues for some or all service classifications included in the RDM.

10 Q. Please describe the RDM Adjustment?

11 A. For each service classification group subject to the RDM, the Company will, on a
12 monthly basis, compare actual delivery revenue to the delivery revenue target. If the
13 monthly actual delivery revenue exceeds the delivery revenue target, the delivery
14 revenue excess will be accrued for refund to customers at the end of the annual RDM
15 period (as described below). Likewise, if the monthly actual delivery revenue is less
16 than the delivery revenue target, this delivery revenue shortfall will be accrued for
17 recovery from customers at the end of the annual RDM period. The annual RDM
18 period is the same as the Rate Year in this proceeding, the twelve months ending
19 October 31, 2010.

20 Q. Please go on.

21 A. On a monthly basis, interest at the NYPSC's rate for other customer provided capital
22 will be calculated on the average of the current and prior month's cumulative delivery
23 revenue excess/shortfall (net of state and federal income tax benefits). At the end of an

GAS RATE PANEL

1 annual RDM period, total delivery revenue excess/shortfalls for each service
2 classification group will be refunded/surcharged to customers through service
3 classification group-specific RDM Adjustments applicable during a subsequent twelve-
4 month period. The Company will file a Statement of RDM Adjustments during the
5 month following the end of an annual RDM period and no less than ten calendar days
6 before the date on which the statement is proposed to be effective. The schedule for
7 RDM adjustments applicable to this rate plan is set forth below.

<u>Annual RDM Period</u>	<u>RDM Adjustment Filing Date</u>	<u>RDM Adjustment Recovery Period</u>
11/1/09 – 10/31/10	11/21/10	12/1/10 – 11/30/11

8
9 The service classification group-specific RDM Adjustments will be determined on a
10 cents per Ccf basis by dividing the total delivery revenue excess/shortfalls for the
11 annual RDM period for each service classification group by forecast Ccf deliveries of
12 the associated service classification group for the corresponding RDM Adjustment
13 Recovery Period. If at any time during an annual RDM period the total of cumulative
14 delivery revenue excess/shortfall for all of the Company's service classifications
15 subject to the RDM exceeds \$3.0 million, the Company will implement interim RDM
16 Adjustments by service classification on no less than ten days notice. These interim
17 RDM Adjustments would be subject to reconciliation at the end of the annual RDM
18 period as part of the annual RDM Adjustment process described above.

19 Q. Do you have any other comments regarding the RDM?

20 A. Yes. The Company is willing to discuss incentives, including the implementation of a
21 revenue per customer mechanism, for promoting economic development by adding
22 new customers and promoting gas conversions. In addition, any RDM implemented

GAS RATE PANEL

1 by the Company must allow the Company to exclude certain of the revenues associated
2 with the gas conversion programs described in the testimony of Company witness
3 Kennedy. Absent such exclusion, the Company will have a severely diminished
4 incentive to pursue such conversions.

5 **LOST AND UNACCOUNTED FOR GAS**

6 Q. What changes are you proposing in the incentive mechanism for lost and unaccounted
7 for gas?

8 A. We are proposing a limit on the incentive/penalty for lost and unaccounted for gas.
9 This incentive/penalty is based, in part, on the cost of gas experienced by the
10 Company. In recent years, gas prices have increased significantly and become more
11 volatile. This increases the magnitude and volatility of line loss incentives/penalties.
12 Therefore, the Company proposes limitations consisting of two components: a limit on
13 the difference between the actual line loss percentage and the line loss percentage upon
14 which the then-current factor of adjustment is based; and a dollar limit. We propose to
15 limit the line loss incentive/penalty to 0.5% above or below the line loss percentage
16 used to determine the factor of adjustment. For example, a factor of adjustment of
17 1.016 reflects losses of 1.57%. If actual line losses are less than 1.57%, the Company
18 would retain the benefit of the difference between the actual loss percentage and 1.57%
19 up to and including 0.5% below the 1.57%, or 1.07%, and would reflect for the benefit
20 of customers any actual line losses below 1.07%. Similarly, if actual line losses are
21 greater than 1.57%, the Company would bear the cost of the difference between 1.57%
22 and actual line losses up to and including 0.5% above the 1.57%, or 2.07%, and
23 customers would bear the cost of any actual line losses more than 2.07%. We are also

GAS RATE PANEL

1 proposing a dollar limitation on this incentive or penalty. We propose that in no event
2 will the Company retain or bear more than \$500,000 for any rate year related to the
3 line loss incentive/penalty.

4 Q. Have you proposed any change in the determination of the factor of adjustment?

5 A. Yes. We propose that the current cap on the factor of adjustment be removed, so that
6 the factor of adjustment be calculated to reflect the Company's most recent three-year
7 average actual line losses, as determined for the 36 months ending on August 31.
8 Removal of the cap is necessary to provide for a more equitable mechanism. We also
9 propose not to change the factor of adjustment if the three-year average actual line
10 losses on which the factor of adjustment is to be based, falls within +/- 5% of the prior
11 three-year average actual line losses.

12 OTHER TARIFF CHANGES

13 Q. Do you propose any other changes to the Company's Schedule for Gas Service?

14 A. Yes. We have also proposed changes related to interruptible transportation service, the
15 POR discount, the Transition Adjustment, the Sharing of Benefits mechanism, the
16 recovery of costs associated with gas in storage working capital, the SC No. 11 rollover
17 option, and the WNA mechanism.

18 Q. Do you propose any changes to interruptible transportation rates?

19 A. Yes. Pursuant to the NYPSC's Rate Order in Case No. 05-G-1494, the Base Charge
20 used to determine the blocked rates for Service Classification No. 8, interruptible
21 transportation service, was capped at \$0.50 per Mcf for the period November 1, 2006
22 through October 31, 2007, \$0.53 per Mcf for the period November 1, 2007 through

GAS RATE PANEL

1 October 31, 2008, and \$0.59 for the period November 1, 2008 through October 31,
2 2009.

3 Q. Do you plan to extend this cap beyond October 31, 2009?

4 A. No. In the absence of the final \$0.59 per Mcf cap established in Case No. 05-G-1494,
5 the cap on the Base Charge will return to its previous level. The Base Charge shall not
6 be greater than (i) the lowest per unit delivery charge for service under Service
7 Classification No. 2 minus (ii) 5.0 cents per Ccf. O&R interruptible transportation
8 customers currently enjoy a delivery rate that is significantly less than the rate for firm
9 service while being subject to very few interruptions. Therefore, O&R's interruptible
10 transportation customers receive a service very close in reliability to firm service, but
11 at a significant discount to firm service rates.

12 Q. How often are O&R's interruptible transportation customers interrupted?

13 A. O&R's interruptible transportation customers have not been interrupted due to
14 distribution system limitations during the eight-year period ending October of 2008.

15 Q. Why are these customers so rarely interrupted?

16 A. According to the NYPSC's policy as described in its August 24, 2000 "Order Directing
17 Utilities To File Revised Interruptible Gas Service Tariffs" (at 13), in Case No. 00-G-
18 0996, "Interruptions are to be for reliability reasons only; economic bases do not
19 support interruptions of customers." Therefore, interruptible transportation customers
20 may be interrupted only for reliability reasons. Of course, a customer may be
21 interrupted by its marketer due to gas supply issues. Since these customers receive a
22 level of service comparable to firm service, the Company does not plan to extend the

GAS RATE PANEL

1 cap. The Company plans to use the flexibility inherent in Service Classification No. 8,
2 where appropriate, to set rates in a manner that maximizes interruptible revenues.

3 Q. Do you propose any other changes to the Company's interruptible transportation
4 service?

5 A. Yes. In addition to the above changes, the necessary tariff revisions have been made to
6 reflect Mr. DiLoreto's proposal to close interruptible transportation service to new
7 customers. Service Classification No. 8 has been modified to close it to new customers
8 effective November 1, 2009. Existing customers under Service Classification No. 8 as
9 of this date would be grandfathered.

10 Q. Please describe your proposed change to the POR discount.

11 A. We are proposing to change the recovery of credit and collection costs associated with
12 the POR program. These costs are currently recovered, through an MFC, from retail
13 access customers whose marketers participate in the POR program. We propose to
14 eliminate the MFC applicable to retail access customers, and recover credit and
15 collections costs through the POR discount applicable to marketers serving firm
16 transportation customers. This change is consistent with the POR discount established
17 for the Company's electric service in Case No. 07-E-0949. The credit and collections
18 component of the POR discount will be determined by dividing the Company's credit
19 and collection expenses attributable to retail access customers whose marketers
20 participate in the Company's POR program by estimated gas supply costs to be billed
21 on marketers' behalf. The credit and collections expense is \$465,113 for the Rate
22 Year. The percentage for credit and collections to be included in the POR discount will
23 be determined prior to the commencement of the Rate Year based on the expense level

GAS RATE PANEL

1 shown above and the Company's then-current forecast of commodity costs to be billed
2 on behalf of marketers through the POR program.

3 Q. Briefly describe the current Transition Adjustment.

4 A. The Transition Adjustment is applied, on a per Ccf basis through the MGA, to the bills
5 of SC No. 1, SC No. 2 and SC No. 6 customers. The Transition Adjustment collects
6 from or credits to customers for the following components: (1) the difference between
7 the MFC Fixed Component lost revenue target (*i.e.*, the competitive supply-related
8 MFC component and the credit and collections MFC component) reflected in rates and
9 the revenues received through the MFCs related to such components; (2) the total of
10 billing and payment processing charges avoided by retail access customers less
11 charges assessed on marketers where the Company issues a Utility Single Bill on
12 behalf of the marketer, less avoided costs associated with billing and payment
13 processing when marketer single bills are issued; (3) the cost of enabling technologies,
14 not to exceed \$100,000 relating to the cost of billing system modifications necessary to
15 implement unbundled charges in accordance with the NYPSC's rate order in Case 05-
16 G-1494; and (4) prior period reconciliations.

17 Q. Please describe your proposed changes to the Transition Adjustment.

18 A. First, the MFC Fixed Component lost revenue target must be changed to reflect the
19 new levels of the competitive supply-related MFC component and the credit and
20 collections MFC component. In addition, the MFC Fixed Component lost revenue
21 target must be modified to remove the credit and collections amount that will be
22 recovered through the POR discount. Next, a new component has been added to the
23 Transition Adjustment to recover credit and collections lost revenue associated with

GAS RATE PANEL

1 retail access. This component is equal to the target level of credit and collections costs
2 reflected in the POR discount minus revenues received through the credits and
3 collections component of the POR discount.

4 Q. Are you proposing any other changes to the Transition Adjustment?

5 A. Yes. We are also eliminating the component to recover the cost of enabling
6 technologies since the cost of billing system modifications necessary to implement
7 unbundled charges have been recovered through the Transition Adjustment.

8 Q. Please describe the current Sharing of Benefits Mechanism.

9 A. In Case No. 05-G-1494, a base rate revenue imputation of \$4.45 million was
10 established. This revenue imputation reflects (i) an imputation for interruptible
11 benefits of \$3.8 million (“Interruptible Benefits Imputation”); and (ii) an imputation of
12 \$650,000 for net benefits associated with the transfer of gas to electric generating
13 facilities previously owned by the Company (“Power Generation Imputation”).
14 Interruptible benefits are defined as total interruptible (S.C. Nos. 3 and 8), firm
15 withdrawable (S.C. Nos. 9 and 10) and firm dual fuel (S.C. No. 5) revenues minus any
16 associated gas costs and revenue tax surcharge revenues. SC No. 10 capacity revenues
17 are not included in the Interruptible Benefits Imputation and 100% of amounts received
18 by the Company are passed back to firm sales customers through the gas supply
19 charge. SC No. 10 delivery revenues are included in the Interruptible Benefits
20 Imputation calculation. Any interruptible revenue variances, either positive or
21 negative, between the actual revenue margin and a \$3,966,500 Sharing Target, during
22 each Rate Year are shared on an 80% customer/20% Company basis and passed
23 back/recovered. The Sharing Target reflects the Interruptible Benefits Imputation and

GAS RATE PANEL

1 an adjustment related to the removal of losses from the blocked rates for SC No. 8 as
2 adopted by the NYPSC in Case No. 05-G-1494. The 80% customer over/under
3 recovery of the Sharing Target is passed back/recovered through the MGA. 100% of
4 any variances, either positive or negative, between the actual revenue margin and the
5 Power Generation Imputation, during each Rate Year are passed back/recovered from
6 customers.

7 Q. What changes are you proposing to the Sharing of Benefits Mechanism?

8 A. As proposed by the Accounting Panel, we are reducing the interruptible benefits
9 imputation from \$3.8 million to \$2.6 million. This change reflects a reduction in the
10 interruptible benefits and the elimination from the mechanism of the \$666,000
11 associated with SC No. 8 losses that was authorized for recovery through the Sharing
12 of Benefits Mechanism in Case No. 05-G-1494. The Accounting Panel has taken these
13 changes into account in determining the incremental revenue requirement. Any
14 variances between actual benefits and the imputation would be shared on an 80%
15 customer / 20% shareholder basis. The revised imputation levels reflect only
16 interruptible benefits. We propose that the Power Generation Imputation continue to
17 be set at \$650,000 and that 100% of any variances, either positive or negative, between
18 the actual revenue margin and the Power Generation Imputation be passed
19 back/recovered from customers.

20 Q. Please describe the current method of recovering storage working capital costs?

21 A. The Company includes in its MFC applicable to SC No. 1 and SC No. 2 customers, and
22 in its MGA applicable to SC Nos. 1, 2 and 6 customers, charges to recover the working
23 capital costs associated with gas in storage. Working capital costs associated with gas

GAS RATE PANEL

1 in storage are determined by multiplying the monthly gas in storage balance by the
2 Commission's Other Customer Capital Rate. Firm transportation customers (SC No. 6)
3 are assessed a charge for storage working capital equal to 20% of the storage working
4 capital charges assessed on firm sales customers (SC No. 1 and SC No. 2) in
5 accordance with the Commission's Order Establishing Rates in Phase 2, issued and
6 effective October 18, 2001 in Case No. 99-G-1695.

7 Storage working capital costs are split between sales-related and reliability/balancing
8 related costs. The charge applicable to SC No. 6 customers, as defined above, is
9 currently deemed to be reliability/balancing related and is recovered from SC No. 1,
10 SC No. 2 and SC No. 6 customers on an equal cents per Ccf basis through the MGA.
11 The difference between the charge applicable to firm sales customers and the charge
12 applicable to firm transportation customers is deemed to be sales-related and is
13 recovered from SC No. 1 and SC No. 2 customers on an equal cents per Ccf basis
14 through the MFC. The Company performs reconciliations of storage working capital
15 costs and recoveries on an annual basis in accordance with the above-referenced order
16 and current tariff provisions.

17 Q. Please describe your proposed changes in the recovery of storage working capital
18 costs?

19 A. We are proposing two changes. First as proposed by Company witness Olmsted, the
20 per Ccf rate associated with reliability/balancing will be set equal to the sales-related
21 per Ccf rate. The SC No. 1, SC No. 2 and SC No. 6 customers will pay the rate
22 associated with reliability/balancing and only the SC No. 1 and SC No. 2 customers
23 will pay the sales-related rate. Therefore, the total rate for working capital associated

GAS RATE PANEL

1 with gas in storage applicable to SC No. 6 customers will be 50% of the total rate
2 applicable to SC No. 1 and SC No. 2 customers. In addition, as proposed by the
3 Accounting Panel, we have changed the carrying charge used in the determination of
4 storage working capital costs from the Commission's Other Customer Capital Rate to
5 the Company's pre-tax weighted average cost of capital.

6 Q. Please describe your proposed change to SC No. 11.

7 A. We have made the appropriate changes in SC No. 11 to implement Company witness
8 Quin's proposal to eliminate the Rollover Option for settling marketers' monthly
9 imbalance volumes (*i.e.*, the difference between the volume of gas specified by the
10 Company for delivery to the citygate and the volume of gas used by the marketer's
11 customers).

12 Q. Have you made any other changes to O&R's gas tariff?

13 A. Yes. We have made two changes to the WNA mechanism. First, we propose to
14 eliminate the deadband within the WNA. With an RDM, any weather related non-
15 competitive delivery revenue excess or shortfall within the deadband, which would not
16 be reconciled by the WNA mechanism, would ultimately be reconciled in the annual
17 RDM reconciliation. By eliminating the deadband, all weather related excesses or
18 shortfalls, as determined by the WNA mechanism, would be reconciled and
19 surcharged/credited to customers monthly, rather than at the end of an annual RDM
20 adjustment period. In addition, as proposed by the Forecasting Panel, we have changed
21 the definition of normal heating degree days ("NHDD") to set the NHDD based on the
22 average weather conditions over the 30 calendar years ended 2007.

GAS RATE PANEL

MARGINAL COST STUDY

2 Q. Have you compared the proposed delivery rates with the marginal costs associated with
3 delivery service?

4 A. Yes. The marginal transmission and distribution (“T&D”) cost analysis described
5 below indicates that the marginal cost of T&D exceeds current delivery rates.

6 Q. Was the marginal cost analysis performed by you?

7 A. Yes. Exhibit G-14, Schedule 4, entitled, “Orange and Rockland Utilities, Inc. – Gas
8 Transmission and Distribution Marginal Costs,” summarizes the results of our analysis.

9 Q. What was the period used to calculate marginal costs?

10 A. We used the five years from January 1, 2009 through December 31, 2013. The period
11 includes the Rate Year – the twelve months ending October 31, 2010.

12 Q. What is the definition of marginal cost?

13 A. Marginal cost is the cost of producing, transmitting, and distributing an additional unit
14 of gas.

15 Q. Did you consider individual marginal cost components?

16 A. For purposes of our testimony, we analyzed marginal T&D costs using embedded
17 customer costs as a surrogate for marginal customer costs.

18 Q. Please define marginal T&D costs.

19 A. Marginal T&D costs are the costs associated with additions and modifications to the
20 T&D system infrastructure that result from increased throughput due to increased sales.
21 This does not include costs associated with service piping or any equipment inside the
22 customer's premises.

23 Q. How did you estimate the marginal T&D costs for this study?

GAS RATE PANEL

1 A. First, we identified capital costs incurred for the T&D system to maintain reliable
2 service under peak design conditions as a result of increased sales. Line 1 in Exhibit
3 G-14, Schedule 4 shows the projected average annual capital investment in the T&D
4 system for the years 2009-2013 that results from increased sales. Next, we calculated
5 the annualized costs associated with the average annual capital cost by applying a
6 carrying charge of 11% plus an additional 8.41% in annual O&M to line 1. The final
7 step in our analysis was to compute the average T&D capital costs per unit of increased
8 sales by dividing the incremental annualized capital costs by the projected increase in
9 annual firm sales. Lines 6 and 7 of Exhibit G-14, Schedule 4 show the computed
10 projected increase in firm sales and the resultant total average marginal T&D cost per
11 unit of increased sales.

GAS LOAD RESEARCH PROGRAM

13 Q. Please describe the program for the purchase and installation of interval metering at
14 sample gas customer locations.

15 A. The Company intends to purchase and install interval meters at sample customer locations
16 to gain a better understanding of the customer hourly demand characteristics of firm
17 service gas customers. These metering locations will be permanent installations equipped
18 with automated reading technology to allow for analysis of customer hourly usage patterns
19 over time. The collection of these data is in keeping with the NYPSC's goal with respect
20 to competitive metering and gas demand-side management.

21 Q. Please describe the capital and annual O&M expenses associated with this project.

22 A. The Company will purchase and install approximately 120 interval meters over the 2010
23 through 2011 period for an overall capital investment of \$203,000 and annual O&M

GAS RATE PANEL

1 expenses of \$13,000 in 2010, \$64,000 in 2011, and \$100,000 in year 2012, respectively.

2 The capital investment will include the metering device and associated equipment. The

3 O&M will include the on-going maintenance of the equipment and telecommunication

4 service fees for data retrieval.

5 Q. Does this conclude your testimony?

6 A. Yes, it does.

7

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
FORECASTING PANEL

NYPSC CASE No. _____

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

3 A. Lucia Merry Padang, Vasken Torossian, and Joanna Ostrowska. Our business address is
4 4 Irving Place, New York, New York 10003.

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

7 A. **(Padang)** I am employed by Consolidated Edison Company of New York, Inc. (“Con
8 Edison”). I am a Senior Analyst in the Gas and Steam section of the Revenue and
9 Volume Forecasting Department of Corporate Accounting. I joined Con Edison in
10 January 2007. My current responsibilities include the development, maintenance and
11 updating of the Orange and Rockland Utilities, Inc. (“O&R” or the “Company”) and Pike
12 County Light & Power Company volume and revenue forecast, and presentation of the
13 forecast under the direction of the Gas and Steam Forecasting section manager. My
14 background is as follows: I received a Bachelor’s Degree in Business Administration
15 from the Royal Melbourne Institute of Technology, Melbourne, Australia in 1994 and a
16 Master’s Degree in Business Administration from the University of Phoenix in 2004. I
17 am also certified as a Professional Forecaster. Prior to working for Con Edison, I worked
18 as a Financial Analyst and Accountant for approximately 12 years.

19 **(Torossian)** I have been employed by Con Edison since 1991. I hold a Bachelor of
20 Engineering Degree in Mechanical Engineering from the City College of New York. I
21 am currently a Senior Planning Analyst in the Gas and Steam section of the Revenue and
22 Volume Forecasting Department in Corporate Accounting. I have been in the Gas and

1 Steam section since 1995. I am responsible for forecasting gas interruptible delivery
2 volumes and resultant revenues for both Con Edison and O&R under the direction of the
3 Gas and Steam Forecasting section manager. I am also responsible for the development
4 of normal weather updates and maintenance of actual weather databases.

5 **(Ostrowska)** I am employed by Con Edison as a Senior Analyst in the Gas and Steam
6 section of the Revenue and Volume Forecasting Department in Corporate Accounting. I
7 joined Con Edison in January 2007. My current responsibilities include developing and
8 updating the small new business gas model for Con Edison and O&R, and assessing the
9 impact of rate changes on Con Edison revenue and volumes and developing the Con
10 Edison revenue forecast under the direction of the Gas and Steam Forecasting section
11 manager. My background is as follows: I received a Bachelor's degree in Business
12 Administration from Pace University in 2002 and I am currently enrolled in the Masters
13 of Business Administration program at Fordham University. Prior to working for the
14 Company, I worked as a Financial Analyst for approximately four years.

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

16 A. The purpose of our testimony is to present the Company's forecast of gas sales volumes
17 and revenues for the rate year, the twelve months ending October 31, 2010 ("Future Rate
18 Year"), as well as forecasts for the 12 month periods ending October 31, 2009, October
19 31, 2011 and October 31, 2012. Our testimony addresses the development of these
20 forecasts starting from the historic year, the twelve months ended June 30, 2008
21 ("Historic Test Year").

22 Q. Please describe the Company's delivery volume forecast methodology.

1 A. The process begins with the weather normalization of the billed Historic Test Year
2 delivery volumes. This normalizes variations in delivery volumes due to warmer or
3 colder than normal weather over the period. The Historic Test Year delivery volumes are
4 also adjusted for the impact on deliveries yet to be realized from customers added during
5 the Historic Test Year and to reflect the anticipated level of new business, which will
6 impact the Future Rate Year. Next, a billing cycle adjustment is made to account for the
7 difference in the average annual billing days during the Historic Test Year and the
8 projected average annual billing days in the Future Rate Year. Lastly, anticipated
9 employment and price changes are factored into the overall forecast projection for the
10 Future Rate Year.

11 Q. Was Schedule 1 of Exhibit ____ (G-3), entitled “ORANGE AND ROCKLAND
12 UTILITIES, INC. - Forecasted Firm Gas Delivery Volumes for the Twelve Months
13 Ending October 31, 2010 (MCF),” prepared by the Forecasting Panel?

14 A. Yes, it was.

15 Q. Please describe this schedule.

16 A. Line 1 of Schedule 1 shows, by service classification grouping, the total annual firm
17 billed gas delivery volumes (“firm billed volumes”) booked by the Company for its
18 service territory during the twelve months ended September 30, 2008. While the forecast
19 process initially begins with the actual results for the Historic Test Year, it was
20 subsequently updated to reflect more current economic data, including sales data, through
21 September 30, 2008. The schedule then details adjustments made to those volumes, as
22 well as anticipated new business and the impact of changes associated with employment

1 and price that are projected to affect the level of Future Rate Year firm billed volumes.

2 All of these elements are projected to affect the level of Future Rate Year firm billed
3 volumes. Factoring in the projected level of unbilled volumes on Line 8, the schedule
4 concludes with Line 9, the Forecasted Firm Delivery Volumes for the Future Rate Year.

5 Q. Please describe the Weather Normalization Adjustment shown on Line 2.

6 A. Line 2 shows the adjustment necessary to recognize that the 12 months ended September
7 30, 2008 Billed Delivery Volumes were lower than expected due to warmer than normal
8 weather. This period, on a degree-day basis, was 3.1% warmer than normal. The related
9 impact on firm billed gas volumes was calculated by multiplying the variation between
10 normal and actual heating degree days, measured on a billing cycle basis, by a use per
11 degree-day per average customer factor times the actual number of customers. The
12 factors, by service classification grouping, were determined by a regression analysis of
13 actual average monthly-billed sales per customer per billing day versus actual monthly
14 billing cycle heating degree-days per billing day. The Weather Normalization
15 Adjustment is estimated to result in 343,390 MCF of additional volume in the Future
16 Rate Year.

17 Q. Please define normal weather.

18 A. The Weather Normalization Adjustment was based on normal weather, which is defined
19 as the average weather conditions over the 30 calendar years ended 2007.

20 Q. Please explain the Net New Business Adjustment shown on Line 3.

1 A. This adjustment estimates the “yet to be realized” impact on future sales from customers
2 added during the course of the Historic Test Year, as well as the estimated realized new
3 business in the Future Rate Year from projected customers added.

4 Q. Please explain how the adjustment was quantified.

5 A. The adjustment first estimates the impact on future delivery volumes based upon the
6 projected annual consumption for the recorded number of customers at the end of June
7 30, 2007, less the actual realized sales during the 12 months ended June 30, 2008,
8 adjusted to normal weather, and is estimated to result in 113,200 MCF of additional
9 volume in the Future Rate Year. In addition, the Net New Business Adjustment reflects
10 the estimated realized new business in the Future Rate Year from projected new
11 customers. The new business forecast classifies new customers into two groupings: (1)
12 large volume commercial customers (*i.e.*, annual usage greater than 2,500 MCF); and (2)
13 residential and small commercial customers (*i.e.*, annual usage less than or equal to 2,500
14 MCF). The large volume new business forecast estimates the volume for known new gas
15 attachments as provided by the Company’s Operations Support Department.
16 Alternatively, the small volume new business forecast considers: (1) the historic
17 relationship of changes in customers and building permits; (2) the projected levels of
18 building permits; and (3) average use per customer. The total forecasted new business
19 volume resulting from anticipated large and small volume new customers added during
20 the July 2008 to October 2010 period is estimated to result in 265,700 MCF of realized
21 volumes in the Future Rate Year. In total, the Net New Business Adjustment is 378,900
22 MCF in the Future Rate Year.

1 Q. Please explain the Billing Cycle Adjustment shown on Line 4.

2 A. This adjustment recognizes the impact on future sales due to the difference in the average
3 annual billing days during the Historic Test Year and the projected average annual billing
4 days in the Future Rate Year. The adjustment was calculated on a monthly basis by
5 multiplying the differences in average billing days and the related difference in normal
6 cycle heating degree days by use per billing day and use per heating degree day factors,
7 which were determined by regression analysis of the Historic Test Year data. The billing
8 schedule for the Historic Test Year had 366.9 billing days. The adjustment was
9 calculated using the projected billing schedules covering the Future Rate Year, which
10 reflects annual billing days of 366.4 days and results in a downward adjustment to
11 volumes of 56,300 MCF.

12 Q. Please explain the Economy Adjustment shown on Line 5.

13 A. The Economy Adjustment on Line 5 represents the anticipated impact of projected
14 changes in employment on future sales. Employment relative to the levels experienced
15 during the historic year is projected to increase sales by 39,200 MCF. Using historical
16 data on employment and the number of customers in the Service Classification ("SC")
17 1/6 Commercial and Industrial service class, we established the relationship that these
18 variables had on SC1/6 Commercial and Industrial sales. We then applied the projected
19 change in employment to the employment coefficient to estimate the impact that the
20 anticipated changes in employment will have on sales in this customer group.

21 Q. Please explain the Price Elasticity Adjustment shown on Line 6.

1 A. The Price Elasticity Adjustment represents the anticipated impact of projected increases
2 in gas prices on customer usage. The Company's Gas Rate Panel estimated that
3 anticipated higher gas commodity costs coupled with the change in delivery rates that
4 went into effect this fall would increase the typical residential gas heating customer's bill
5 this winter by approximately 8.2%. We applied a price elasticity coefficient of 0.15 and
6 estimated that the increase in bills this winter would reduce SC1/6 Residential Heating
7 volumes by approximately 1.1% or 151,000 MCF. For SC1/6 Commercial gas heating
8 customers, the Company's Gas Rate Panel estimates the increase in customers' bills this
9 winter will be approximately 28.8%. A price elasticity coefficient of 0.2 was applied and
10 indicated that the increase in bills this winter would reduce SC1/6 Commercial Heating
11 volume by approximately 5.0% or 116,900 MCF. In total, the Price Elasticity
12 Adjustment amounts to a 267,900 MCF reduction in the Future Rate Year.

13 Q. Have you made any estimates of further reductions in sales for the winters beyond the
14 winter of 2008/2009 due to higher gas prices?

15 A. Yes. The Company's Gas Rate Panel, based on preliminary estimates of future required
16 delivery rate relief coupled with projected changes in gas commodity costs, provided us
17 with estimates of bill increases by service classification for the winters of 2010/2011 and
18 2011/2012. At the time of the preparation of the forecast, notwithstanding the rate relief
19 sought in this proceeding, gas bills were not anticipated to increase in the winter of
20 2009/2010 relative to winter 2008/2009. For the winters 2010/2011 and 2011/2012, the
21 forecast reflects the projected impact due to anticipated bill increases as a result of higher
22 delivery charges and commodity costs. However, history has shown gas costs to be

difficult to predict and projected gas costs could increase above current estimates and result in additional reductions in customer usage beyond the levels forecasted at this time.

Q. What are the Forecasted Firm Billed Delivery Volumes for the Future Rate Year?

A. The Forecasted Firm Billed Delivery Volumes for the Future Rate Year as shown on Line 7 are 19,709,990 MCF, a 150,200 MCF change from the 12 months ended September 30, 2008, adjusted to normal weather and the billing schedule of the Future Rate Year. This represents a forecasted annual growth rate of 0.4 %.

Q. Please explain the Unbilled Delivery Volumes shown on Line 8.

A. The Unbilled Delivery Volumes represent an estimate of the amount of gas volumes anticipated to be delivered to firm customers by the end of the Future Rate Year, but not yet billed since the volumes would be delivered after the conclusion of October 31, 2010 customer meter readings. The unbilled delivery volumes are the difference between the calendar delivery volumes and the billed delivery volumes for the Future Rate Year. Each billing cycle contains delivery volumes for the current month and the prior month depending on the customer meter reading schedule for the month. By following the meter reading schedule and associated normal heating degree-days, the percentage of the prior month's delivery volumes and current month's delivery volumes are developed. These percentages are applied to the forecasted billed delivery volumes to develop the monthly level of calendar delivery volumes. The billed delivery volumes are subtracted from the calendar delivery volumes, resulting in the unbilled delivery volumes. As shown on Line 8, the Unbilled Delivery Volumes for the Future Rate Year are estimated to be 168,630 MCF.

1 Q. What are the Forecasted Total Firm Delivery Volumes for the Future Rate Year?

2 A. As shown on Line 9, the Forecasted Total Firm Delivery Volumes for the Future Rate

3 Year are 19,878,620 MCF.

4 Q. Has the Forecasting Panel made a forecast of firm delivery volumes for the 12 month

5 period ending October 31, 2009?

6 A. Yes, we have.

7 Q. Is that forecast shown on Schedule 2 of Exhibit ____ (G-3), a one page schedule entitled

8 “ORANGE AND ROCKLAND UTILITIES, INC. – Forecasted Firm Gas Delivery

9 Volumes for the Twelve Months Ending October 31, 2009 (MCF)” and was this schedule

10 prepared by you?

11 A. Yes, it was.

12 Q. Please describe this schedule.

13 A. This schedule is laid out in exactly the same format as Schedule 1 of Exhibit ____ (G-3). It

14 lists the same variables anticipated to impact the 12 months ending October 31, 2009 and

15 quantifies their projected impact on this period. The firm billed delivery volumes for the

16 12 months ending October 31, 2009, as shown on line 7 are projected to be 19,398,190

17 MCF, no significant change from the 12 months ended September 30, 2008 level,

18 adjusted to normal weather and the billing schedule of the 12 months ending October 31,

19 2009.

20 Q. What are the Forecasted Total Firm Delivery Volumes for the 12 months ended October

21 31, 2009?

1 A. As shown on Line 9, the Forecasted Total Firm Delivery Volumes for the 12 months
2 ending October 31, 2009 are 19,546,770 MCF.

3 Q. Has the Forecasting Panel also developed firm delivery volume forecasts for the 12
4 months ending October 31, 2011 and for the 12 months ending October 31, 2012?

5 A. Yes.

6 Q. Are those forecasts shown on Schedule 3 of Exhibit ____ (G-3), a one page document
7 entitled "ORANGE AND ROCKLAND UTILITIES, INC. – Forecasted Firm Gas
8 Delivery Volumes for the Twelve Months Ending October 31, 2011 and October 31,
9 2012 (MCF)" and was this schedule prepared by the Forecasting Panel?

10 A. Yes. It was.

11 Q. Please describe this schedule.

12 A. This schedule is laid out in a similar manner of Schedules 1 and 2 of Exhibit ____ (G-3).
13 It begins with the forecasted firm delivery volumes for the Future Rate Year, and then
14 lists and quantifies the variables projected to impact firm delivery volumes for the 12
15 months ending October 31, 2011 and the 12 months ending October 31, 2012.

16 Q. Was Schedule 4 of Exhibit ____ (G-3), entitled "ORANGE AND ROCKLAND
17 UTILITIES, INC. – Forecasted Gas Delivery Revenues for the Twelve Months Ending
18 October 31, 2010", prepared by the Forecasting Panel?

19 A. Yes, it was.

20 Q. Please describe this schedule.

21 A. Column 1 shows by service classification grouping, the annual gas delivery volumes
22 forecasted for the Future Rate Year. The service classification groupings in this schedule

1 of the Exhibit have been changed as compared to the first Schedule in order to group
2 similarly priced volumes together. The SC 1/6 Residential customers have been
3 consolidated into one grouping, Residential & Domestic, due to its shared pricing
4 structure. The SC 2/6 Commercial and Industrial grouping has been expanded into two
5 groupings, SC 2/6 Commercial and Industrial and SC 6 Large Commercial and Industrial
6 Transportation. The SC 6 Large Commercial and Industrial Transportation customers
7 pay a higher minimum bill compared to the smaller (*i.e.*, less than 5,000 MCF per year)
8 SC 6 Commercial and Industrial Transportation customers. Column 2 shows the
9 projected Non-Competitive Delivery Revenues related to SC groupings SC 1/6
10 Residential - Domestic and Heating, SC 1/6 Commercial and Industrial Heating, SC 2/6
11 General Service and SC 6 Large Commercial and Industrial Transportation based on the
12 November 1, 2008 rates. The projected Delivery Revenues shown for SC5 (Firm Dual
13 Fuel), SC8/13 Interruptible Transportation service, and SC10 (Withdrawable sales), were
14 estimated based on actual average delivery rates during the Historic Test Year times
15 projected delivery volumes. Column 3 shows the Competitive Delivery Revenues, which
16 include Billing and Payment Processing Charges and Merchant Function Charge
17 Revenues. Column 4 shows the Monthly Gas Adjustment charge revenues. Column 5
18 shows the projected Gas Supply charge revenues for the Future Rate Year as provided by
19 Company witness Olmsted. Gas Supply Charges associated with SC10 (\$6,176,000)
20 reflect gas costs from November 1, 2009 through January 31, 2010 only. SC10 customer
21 (one customer) is assumed to change from full service to transportation only service
22 starting February 1, 2010. Column 6 includes data provided by the Company's

Accounting Panel and shows the Increase in Rates and Charges associated with the revenues from Columns 2, 3, 4 and 5. Column 7, labeled Total Revenue, shows the sum of Column 2, Column 3, Column 4, Column 5, and Column 6. Column 8 shows the Proposed Rate Increase inclusive of the associated Increase in Rates and Charges. Lastly, Column 9 shows the forecast of Total Revenue at the proposed rates, which is the sum of Column 7 and Column 8.

Q. Please describe what the Gas Delivery Volumes in Column 1 represent.

A. Column 1 shows the projected firm and interruptible delivery volumes for the Future Rate Year on a “per service” classification grouping and total basis. The development of the projected firm gas volumes was described earlier in our testimony. The development of the projected interruptible gas volumes begins with actual individual customer delivery volume data from the Historic Test Year. For those customers that have heating patterns, the actual volume is adjusted for normal weather. The Historic Test Year actual volumes are also adjusted for actual Company curtailments that occurred during the Historic Test Year, leap day adjustment (the Historic Test Year has one additional billing day due to leap year), anticipated level of new business that will impact the Future Rate Year, and forecast Company curtailments based on normal weather that will impact the Future Rate Year.

Q. Please explain the methodology used to calculate Delivery Revenue for the forecasted firm volumes.

A. The non-competitive delivery revenues on Line 1, SC 1/6 Residential – Domestic and Heating were calculated in two components. First, a pricing curve based on the

1 relationship between actual delivery volumes and delivery revenues was applied to the
2 projected delivery volumes in the Future Rate Year, excluding the new business volume
3 forecasted for the projected new customers added after June 2008. The non-competitive
4 delivery revenues associated with new business volumes were calculated by pricing the
5 volumes “through the blocks.” In effect, the average use per new customer was
6 calculated and priced according to the November 1, 2008 tariff rates. The delivery
7 revenue per new customer was then multiplied by the projected number of new customers
8 to calculate the total non-competitive delivery revenues for new business. This “through
9 the blocks” methodology includes the minimum bill charges associated with new
10 customers. If the new business was priced utilizing the pricing curve, the non-
11 competitive delivery revenues would be understated, since the pricing curve would treat
12 the new business volumes as incremental volumes, not capturing the additional minimum
13 bill revenue associated with new customers. In continuation, the non-competitive
14 delivery revenues derived from the pricing curve were added to the new business delivery
15 revenues resulting in total non-competitive delivery revenue of \$63,197,000 as shown on
16 Line 1 in Column 2. The non-competitive delivery revenues for SC 1/6 Commercial &
17 Industrial Heating and SC 2/6 Commercial and Industrial, Lines 2 and 3, respectively,
18 were calculated using the same methodology. The non-competitive delivery revenues for
19 SC 6 Large Commercial and Industrial Transportation were calculated using the “through
20 the blocks” methodology, which was the same methodology utilized in developing the
21 non-competitive delivery revenues for new business. The SC 6 Large Commercial and
22 Industrial Transportation grouping represents a very small number of customers and due

1 to the size of the group and previously mentioned pricing structure (high minimum bill
2 and a single incremental rate), the “through the blocks” methodology was applied to
3 quantify the non-competitive delivery revenues for the service class grouping.

4 Q. How did you determine the proposed rate increase revenues shown in Column 8?

5 A. The proposed rate increase revenues of \$17,773,000 were provided by the Accounting
6 Panel. This proposed rate increase includes \$183,000 related to increase in rates and
7 charges. The increase of \$ 17,590,000 net of increase in rates and charges reflects the net
8 impact of a \$17,925,000 non-competitive delivery rate increase offset by a \$335,000
9 decrease in competitive service revenues. The proposed percentage increase to firm
10 customers (assuming firm transportation customers purchase gas at the Company average
11 Gas Supply Charge) is 4.8%.

12 Q. Have you calculated unbilled revenues for the Future Rate Year?

13 A. Yes. The unbilled revenues were calculated by utilizing monthly average rates associated
14 with the Forecasted Firm Billed Delivery Volumes and Non-Competitive Delivery
15 Revenues. The average rates during the Future Rate Year were calculated by service
16 classification grouping and then applied to the unbilled delivery volumes, which were
17 prorated according to the amount of billed delivery volumes in each service
18 classifications grouping for the Future Rate Year.

19 Q. Has the Forecast Panel priced out the projected firm volume non-competitive delivery
20 revenues at current rates for the 12 months ending October 31, 2011 and the 12 months
21 ending October 31, 2012?

22 A. Yes.

1 Q. Are those projections shown on Schedule 5 of Exhibit ____ (G-3), entitled “ORANGE
2 AND ROCKLAND UTILITIES, INC. GAS FIRM DELIVERY VOLUMES AND NON-
3 COMPETITIVE DELIVERY REVENUES (Billed and UnBilled)” and was this schedule
4 prepared by the Forecasting Panel?

5 A. Yes. This schedule shows total firm delivery volumes and non-competitive delivery
6 revenues for the 12 months ending October 31, 2010, October 31, 2011, and October 31,
7 2012.

8 Q. Has the Forecasting Panel projected the forecasted non-fuel related revenues associated
9 with the projected interruptible volumes for the 12 month periods ending October 31,
10 2010, October 31, 2011 and October 31, 2012?

11 A. Yes, those projections are shown on Schedule 6 of Exhibit ____ (G-3), a one page
12 document entitled “ORANGE AND ROCKLAND UTILITIES, INC. GAS
13 INTERRUPTIBLE DELIVERY VOLUMES AND DELIVERY REVENUES,” which
14 was prepared by the Forecasting Panel.

15 Q. Do you have any additional comments regarding the firm delivery volume and revenue
16 forecasts?

17 A. Yes. At the time of this filing, the deteriorating state of the economy continues to be a
18 major concern. It appears that we have entered into a recession, the length of which is
19 impossible to predict. Specifically, the ultimate impact that economic conditions will
20 have on usage by existing customers, as well as on the potential for growth in customers,
21 cannot be predicted with any certainty. Accordingly, we plan to monitor ongoing sales,
22 gas costs projections, as well as updated economic indicators during the course of this

1 proceeding and update the sales and revenue forecasts, as appropriate. The Company's
2 Gas Rate Panel addresses the Company's proposal for a Revenue Decoupling Mechanism
3 ("RDM"). The Commission's adoption of a properly designed RDM for the Company's
4 gas operations would address much of the Company's concerns relating to the forecast
5 for sales and associated revenues in the setting of rates in this proceeding.

6 **RDM REVENUE TARGETS**

7 Q. Have you computed revenue targets at the proposed rates for each of the rate groups
8 described by Company's Gas Rate Panel?

9 A. Yes.

10 Q. Were those targets, shown on a one page document entitled "ORANGE AND
11 ROCKLAND UTILITIES, INC. Proposed Revenue Decoupling Mechanism Targets for
12 the Twelve Months Ending October 31, 2010," prepared by the Forecasting Panel?

13 A. Yes.

14 Q. Please describe this exhibit.

15 A. This exhibit shows the proposed total Rate Year RDM targets by RDM group. The Rate
16 Year RDM targets, in total, represent the proposed firm billed non-competitive delivery
17 revenues of \$102,250,000, exclusive of increase in rates and charges. This \$102,250,000
18 is comprised of \$84,325,000 at current rates plus the proposed delivery rate increase of
19 \$17,925,000.

20 Q. Please explain how you developed these RDM targets by RDM group.

1 A. The Gas Rate Panel provided us with the proposed rate increase revenues by RDM group.
2 For each RDM group, these proposed rate increase revenues were then added to their
3 non-competitive delivery revenue at current rates, as shown on Exhibit G-4, Schedule 4.

4 Q. The Company's Gas Rate Panel has, as part of the Company's proposed RDM,
5 recommended that the current deadband around normal weather conditions used in
6 determining Weather Normalization Adjustment ("WNA") surcharges or credits be
7 eliminated. How should WNA normal weather be defined during the Future Rate Year?

8 A. Normal weather should be defined as the average weather conditions over the 30 calendar
9 years ended 2007. Additionally, should this proceeding result in a multi-year rate order,
10 this definition should continue to be used over the term of any such multi-year plan.

11 Q. Does this conclude your testimony?

12 A. Yes, it does.

ORANGE AND ROCKLAND UTILITIES, INC.
TESTIMONY OF
MICHAEL J. THORPE
NYPSC CASE NO. _____

1 Q. Please state your name and business address.

2 A. Michael J. Thorpe, 390 West Route 59, Spring Valley, New York 10977.

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

4 A. I am employed by Orange and Rockland Utilities, Inc. ("O&R" or "the
5 Company") as Section Manager – Customer Support Operations. In this position
6 I manage a department responsible for the Company's credit, collection and
7 accounts receivable processes, as well as complaint management process.

8 Q. Please describe your educational background and professional experience.

9 A. In 1988, I graduated from the State University of New York at Buffalo with a
10 Bachelor of Science degree in Mechanical Engineering. In 1995, I graduated
11 from Iona College, New Rochelle, New York with a Master of Business
12 Administration degree in Management Information Systems. My first
13 employment was with Consolidated Edison Company of New York, Inc. in 1988
14 as a Management Intern. In 1990, I joined O&R as an Associate Program
15 Administrator – Demand-Side Management. I have since held the positions of
16 Program Administrator – Demand Side Management, Sr. Energy Management
17 Engineer, Regulatory Administrator and Section Manager – Retail Access /
18 Energy Services prior to my present position.

19 Q. Have you ever testified before the New York Public Service Commission
20 ("NYPSC")?

21 A. Yes. I provided rebuttal testimony in NYPSC Case No 06-E-1433 and initial
22 testimony in Case 07-E-0949.

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

ORANGE AND ROCKLAND UTILITIES, INC.
TESTIMONY OF
MICHAEL J. THORPE
NYPSC CASE NO. _____

1 A. I will address O&R's existing Customer Service Performance Incentive ("CSPI").

2 Q. Should O&R continue to have a CSPI?

3 A. No. O&R focuses on providing superior customer service and does not require a
4 CSPI to provide such service. Furthermore, penalties are negative and are a poor
5 substitute for constructive regulation. If penalties are to be prescribed, they
6 should apply solely in cases where actions within the Company's reasonable
7 control have led to plainly and unequivocally unacceptable service levels.
8 Penalties should not apply as the result of unavoidable contingencies and
9 unforeseen economic contingencies. As discussed below, this is exactly what
10 occurred when the Company was penalized due to negative customer survey
11 results attributable to customer dissatisfaction regarding the rapid rise in
12 commodity prices - - something over which the Company has no control.

13 Q. Please continue.

14 A. Under reasonable regulation, utilities should be responsible for managing their
15 operations in an efficient and economical manner. The regulator's role is to
16 provide general oversight and guidance that protects customers from abuses. The
17 Commission's current "incentive structure" rejects positive incentives and
18 penalizes utilities for results that are not abuses. The incentive structure that has
19 evolved over the years clearly needs to be repositioned in order to align itself to
20 the appropriate role for regulatory authority.

21 Q. If the Commission were to continue to impose a CSPI on O&R, should any
22 modifications be made to the CSPI?

23 A. Yes, the CSPI should be in line with what I have said.

ORANGE AND ROCKLAND UTILITIES, INC.
TESTIMONY OF
MICHAEL J. THORPE
NYPSC CASE NO. _____

1 Q. Please describe the existing CSPI.

2 A. The existing CSPI mechanism consists of targets for annual surveys of residential
3 and commercial/industrial customers, and an annual NYPSC complaint rate
4 target. Customer assessment score targets of 6.11 and 6.18 were established for
5 residential (RCAS) and commercial/industrial (CICAS) customer satisfaction
6 surveys, respectively. For NYPSC complaints, penalties are incurred at annual
7 complaint rate levels of 2.5, 2.6 and 2.7 complaints per 100,000 customers or
8 higher. Penalties for minimum and intermediate levels are reduced in any year in
9 which the complaint rate for the preceding year is 0.9 or less. Certain exclusions
10 are applicable to certain types of complaints for purposes of this performance
11 mechanism. The exclusions include duplicative rate consultant complaints, and
12 high commodity prices complaints.

13 Q. Please describe the penalty levels under the existing CSPI.

14 A. Under the existing CSPI, O&R may incur total annual penalties of up to
15 \$600,000. Specifically, O&R may be penalized (a) up to \$150,000 annually for
16 failing to meet the RCAS target, (b) up to \$150,000 annually for failing to meet
17 the CICAS target, and (c) up to \$300,000 for failing to meet the annual complaint
18 rate target.

19 Q. Please describe the modifications you propose to make to the existing CSPI
20 mechanism?

21 A. Currently, the penalties associated with the residential and business surveys are
22 structured on an "all or nothing" basis. The Company would recommend that the
23 survey portions of the CSPI incorporate tiered penalties similar to those relating to

ORANGE AND ROCKLAND UTILITIES, INC.
TESTIMONY OF
MICHAEL J. THORPE
NYPSC CASE NO. _____

1 the complaint rate target. Furthermore, the existing survey targets for penalties,
2 which are weighted heavily on price opinion, should be modified to be consistent
3 with the targets approved by the Commission in the Company's most recent
4 electric base rate case, *i.e.*, Case 07-E-0949. These approved targets exclude
5 price opinion. In addition, the entire CSPI should be structured more
6 symmetrically so as to provide positive financial incentives for achieving
7 "exceptional" performance in the complaint rate and for exceeding survey targets
8 by significant margins in the surveys.

9 Q. Can you provide a schedule that illustrates your proposal?

10 A. Yes. In the event the NYPSC decides that O&R should continue with a CSPI,
11 Exhibit G-15 sets forth a proposal that provides for tiered penalties for the RCAS
12 and CICAS surveys using the targets and tier levels as approved by the NYPSC in
13 Case 07-E-0949, as well as positive incentives for both the surveys and complaint
14 rate.

15 Q. Does this conclude your testimony?

16 A. Yes, it does.

ORANGE AND ROCKLAND UTILITIES, INC.

INDEX OF SCHEDULES

Historical Financial Data - Gas

<u>SCHEDULE</u>	<u>TITLE OF SCHEDULE</u>	<u>WITNESS</u>
1	Balance Sheet	Accounting Panel
2	Statement of Retained Earnings	"
3	Net Book Value of Gas Plant in Service	"
4	Net Book Value of Common Plant in Service	"
5	Statements Showing Gas Plant in Service and Average Cost per Customer	"
6	Statement of Income	"
7	Statement of Gas Operation and Maintenance Expenses	"
8	Gas Operation and Maintenance Expenses, Taxes and Depreciation per Thousand Cubic Feet of Gas Sold	"
9	Operating Taxes - Account 408 - Gas	"
10	Gas Operating Revenues per Thousand Cubic Feet of Gas Sold	"

ORANGE AND ROCKLAND UTILITIES, INC.
BALANCE SHEET

Exhibit G-1
Schedule 1
Page 1 of 2

<u>ASSETS AND OTHER DEBITS</u>	<u>Dec. 31, 2004</u>	<u>Dec. 31, 2005</u>	<u>Dec. 31, 2006</u>	<u>Dec. 31, 2007</u>	<u>June 30, 2008</u>
<u>Utility Plant</u>					
Electric Plant in Service	\$595,410,428	\$628,022,025	\$671,181,011	\$712,494,165	\$742,144,323
Gas Plant in Service	334,566,052	359,503,727	383,565,918	401,855,877	411,513,309
Common Utility Plant in Service	121,247,980	123,623,999	124,923,735	130,055,269	134,058,616
Electric Plant Held for Future Use	759,907	642,681	3,791,002	4,193,699	4,665,596
Gas Plant Held for Future Use	22,214	22,214	210,335	210,335	210,335
Construction Work in Progress	22,741,457	29,034,664	35,018,203	50,391,021	37,864,108
Total Utility Plant	<u>1,074,748,038</u>	<u>1,140,849,310</u>	<u>1,218,690,204</u>	<u>1,299,200,366</u>	<u>1,330,456,288</u>
Accumulated Provision for Depreciation:					
Electric	204,729,442	212,667,255	221,099,526	228,150,085	235,731,300
Electric Plant Held for Future Use	164,947	167,059	71,377	74,162	75,554
Gas	105,828,487	111,762,480	117,576,739	124,191,545	128,466,242
Gas Plant Held for Future Use	4,961	5,376	-	-	-
Common	58,857,920	62,943,439	66,838,712	67,033,400	69,885,609
Total Accum. Provision for Depreciation	<u>369,585,757</u>	<u>387,545,609</u>	<u>405,586,354</u>	<u>419,449,192</u>	<u>434,158,706</u>
Net Utility Plant	<u>705,162,281</u>	<u>753,303,701</u>	<u>813,103,850</u>	<u>879,751,174</u>	<u>896,297,581</u>
<u>Other Property and Investments</u>					
Nonutility Property	65,168	57,958	57,958	57,958	57,958
Accumulated Provision for Depreciation	(87,091)	(87,496)	(88,104)	(88,711)	(53,077)
Investments in Subsidiary Companies	132,915,554	143,933,249	157,161,579	171,701,900	175,705,010
Other Special Funds	-	-	-	13,200,000	13,200,000
Total Other Property and Investments	<u>132,893,631</u>	<u>143,903,711</u>	<u>157,131,433</u>	<u>184,871,147</u>	<u>188,909,892</u>
<u>Current and Accrued Assets</u>					
Cash	2,026,111	73,427	621,234	(167,166)	586,316
Other Special Deposits	1,000	1,000	1,000	-	-
Working Funds	15,700	15,700	11,605	15,700	(30,719)
Temporary Cash Investments	4,616,316	56,043	14,462	49,896,722	32,008
Customer Accounts Receivable	43,495,992	50,679,154	61,475,163	40,977,437	54,865,143
Other Accounts Receivable	2,746,277	36,363,134	43,042,155	26,695,611	23,992,832
Accum. Prov. for Uncollectible Accounts	(3,784,957)	(3,667,563)	(3,034,615)	(3,800,428)	(4,520,212)
Accounts Receivable from Assoc. Cos.	40,998,554	45,576,942	29,089,161	12,112,540	53,479,931
Materials and Supplies	4,416,239	4,982,156	5,372,434	5,997,588	7,271,484
Gas Stored Underground	42,528,761	61,479,360	56,829,269	42,916,976	46,954,875
Prepayments	11,314,221	10,572,362	9,854,317	10,455,705	6,023,942
Accrued Utility Revenue	22,214,869	23,060,636	28,166,158	32,762,344	27,654,681
Misc. Current and Accrued Assets	10,667,978	10,914,340	11,812,329	11,745,122	11,449,450
Derivative Instrument Assets - Hedges	9,026,067	53,917,492	1,037,421	13,912,861	121,519,248
Total Current and Accrued Assets	<u>190,283,128</u>	<u>294,024,183</u>	<u>244,292,093</u>	<u>243,521,012</u>	<u>349,278,979</u>
<u>Deferred Debits</u>					
Unamortized Debt Expense	6,027,717	5,867,017	5,859,157	5,271,866	4,978,020
Extraordinary Property Losses	-	-	-	-	-
Prelim. Survey and Investigation Charges	-	-	-	-	-
Clearing Accounts	-	-	1,956	1,346	(269,898)
Miscellaneous Deferred Debits *	180,734,180	203,261,543	395,532,756	367,899,230	346,767,359
Investment in Research and Development	1,073,412	1,597,794	2,876,529	1,040,070	1,801,532
Accum. Deferred Federal Income Tax	50,107,334	52,127,309	65,035,221	62,131,311	59,574,873
Total Deferred Debits	<u>237,942,643</u>	<u>262,853,663</u>	<u>469,305,619</u>	<u>436,343,823</u>	<u>412,851,887</u>
Total Assets and Other Debits	<u>\$1,266,281,683</u>	<u>\$1,454,085,257</u>	<u>\$1,683,832,997</u>	<u>\$1,744,487,156</u>	<u>\$1,847,338,338</u>

* Includes Regulatory Assets

ORANGE AND ROCKLAND UTILITIES, INC.
BALANCE SHEET

Exhibit G-1
Schedule 1
Page 2 of 2

<u>LIABILITIES AND OTHER CREDITS</u>	<u>Dec. 31, 2004</u>	<u>Dec. 31, 2005</u>	<u>Dec. 31, 2006</u>	<u>Dec. 31, 2007</u>	<u>Jun. 30, 2008</u>
<u>Proprietary Capital</u>					
Common Stock Issued	\$5,000	\$5,000	\$5,000	\$5,000	\$5,000
Preferred Stock Issued	-	-	-	-	-
Preference Stock Issued	-	-	-	-	-
Premium on Capital Stock	193,995,052	194,507,223	194,507,223	194,507,223	194,507,223
Other Paid in Capital	(10,034,344)	(8,116,585)	(33,757,136)	6,550,926	43,972,483
Capital Stock Expense	-	-	-	(149,853)	(149,853)
Retained Earnings	87,981,192	55,360,841	59,758,096	60,662,613	56,692,492
Unappropriated Undistributed					
Subsidiary Earnings	115,817,830	126,835,525	140,063,855	154,604,176	158,607,286
Total Proprietary Capital	<u>387,764,730</u>	<u>368,592,004</u>	<u>360,577,038</u>	<u>416,180,085</u>	<u>453,634,631</u>
<u>Long term Debt</u>					
Bonds	-	-	-	-	-
Other Long Term Debt	279,000,000	319,000,000	394,000,000	394,000,000	344,220,000
Unamort. Prem. on Long Term Debt	-	-	-	-	-
Unamortized Disc. on Long Term Debt	(1,064,509)	(1,022,787)	(1,032,336)	(894,969)	(826,285)
Total Long Term Debt	<u>277,935,491</u>	<u>317,977,213</u>	<u>392,967,664</u>	<u>393,105,031</u>	<u>343,393,715</u>
<u>Current and Accrued Liabilities</u>					
Notes Payable	35,775,000	136,893,500	73,550,000	64,900,000	96,500,000
Accounts Payable	59,209,816	68,402,018	63,166,165	77,002,646	71,270,448
Accounts Payable to Assoc. Cos.	42,696,230	34,434,759	68,946,859	90,957,493	61,006,861
Customer Deposits	11,984,906	11,558,696	12,035,540	12,322,499	12,441,457
Taxes Accrued	1,834,601	1,414,198	2,281,816	1,006,650	408,496
Interest Accrued	4,474,591	4,783,560	8,184,244	10,354,146	11,121,650
Dividends Declared	-	-	-	-	800,000
Tax Collections Payable	1,253,365	865,053	1,056,311	1,105,219	1,217,842
Derivative Instrument Liabilities - Hedges	15,693,619	13,326,387	11,532,466	10,712,838	11,183,440
Misc. Current and Accrued Liabilities	78,116,732	75,906,469	111,588,112	80,639,501	73,704,153
Total Current and Accrued Liabilities	<u>251,038,860</u>	<u>347,584,640</u>	<u>352,341,513</u>	<u>349,000,992</u>	<u>339,654,348</u>
<u>Deferred Credits</u>					
Customer Advances for Construction	1,461,953	1,997,897	2,092,638	2,172,496	2,182,972
Other Deferred Credits	62,981,698	121,570,969	68,853,646	59,740,880	172,922,660
Accum. Def. Investment Tax Credits	3,732,806	3,364,021	3,060,476	2,749,346	2,593,780
Accumulated Deferred Income Taxes:					
Accelerated Amortization	-	-	-	-	-
Liberalized Depreciation	112,500,742	116,587,265	120,455,591	126,343,277	129,167,666
Other	72,131,068	79,206,582	87,894,266	98,534,578	100,056,521
Total Deferred Credits	<u>252,808,267</u>	<u>322,726,734</u>	<u>282,356,617</u>	<u>289,540,577</u>	<u>406,923,598</u>
<u>Operating Reserves</u>					
Property Insurance Reserve	-	-	-	-	-
Injuries and Damages Reserve	6,220,000	6,030,000	6,019,496	6,305,125	6,890,894
Pensions and Benefits	87,249,760	90,750,143	289,326,343	290,142,678	299,602,065
Miscellaneous Operating Reserves	3,264,575	424,522	244,324	212,668	(2,760,913)
Total Operating Reserves	<u>96,734,335</u>	<u>97,204,665</u>	<u>295,590,163</u>	<u>296,660,471</u>	<u>303,732,046</u>
 Total Liabilities & Other Credits	 <u>\$1,266,281,683</u>	 <u>\$1,454,085,257</u>	 <u>\$1,683,832,997</u>	 <u>\$1,744,487,156</u>	 <u>\$1,847,338,338</u>

ORANGE AND ROCKLAND UTILITIES, INC.
Statement of Retained Earnings

Exhibit G-1
Schedule 2

<u>RETAINED EARNINGS (216)</u>	<u>Dec. 31, 2004</u>	<u>Dec. 31, 2005</u>	<u>Dec. 31, 2006</u>	<u>Dec. 31, 2007</u>	<u>June 30, 2008</u>
Unappropriated Retained Earnings - Beginning of Period	\$42,976,440	\$87,981,192	\$55,360,841	\$59,758,096	\$ 64,679,795
Balance Transferred from Income (A)	35,004,751	38,379,649	32,397,255	31,904,516	23,012,697
Dividends Declared:					
Preferred Stock	-	-	-	-	-
Preference Stock	-	-	-	-	-
Common Stock	(28,000,000)	(71,000,000)	(28,000,000)	(31,000,000)	(31,000,000)
Dividend Received from Subsidiary	38,000,000	-	-	-	-
Net Change to Unappropriated Retained Earnings	7,004,751	(32,620,351)	4,397,255	904,516	(7,987,303)
Unappropriated Retained Earnings - End of Period	<u>\$87,981,192</u>	<u>\$55,360,841</u>	<u>\$59,758,096</u>	<u>\$60,662,613</u>	<u>\$ 56,692,492</u>

UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (216.1)

Unappropriated Undistributed Subsidiary Earnings - Beginning of Period	\$143,177,489	\$115,817,830	\$126,835,525	\$140,063,855	\$145,248,561
Add: RECO Dividend	(38,000,000)	-	-	-	-
Equity in Earnings for Period (A)	10,640,341	11,017,695	13,228,330	14,540,321	13,358,725
Other Changes (Merger)	-	-	-	-	-
Unappropriated Undistributed Subsidiary Earnings - End of Period	<u>\$115,817,830</u>	<u>\$126,835,525</u>	<u>\$140,063,855</u>	<u>\$154,604,176</u>	<u>\$158,607,286</u>

(A) Reconciliation of Net Income to Balance
Transferred from Net Income:

Net Income	\$45,645,092	\$49,397,344	\$45,625,585	\$46,444,837	\$36,371,422
Equity in Subsidiary Earnings	10,640,341	11,017,695	13,228,330	14,540,321	13,358,725
Balance Transferred from Income	<u>\$35,004,751</u>	<u>\$38,379,649</u>	<u>\$32,397,255</u>	<u>\$31,904,516</u>	<u>\$23,012,697</u>

ORANGE AND ROCKLAND UTILITIES, INC.
Net Book Value of Gas Plant in Service
December 31, 2004

Exhibit G-1
Schedule 3
Page 1 of 10

	Gas Plant in Service	Accumulated Provision for Depreciation & Amortization	Net Book Value
<u>INTANGIBLE PLANT</u>			
Franchises and Consents	\$20,826	\$6,933	\$13,893
Total Intangible Plant	20,826	6,933	13,893
<u>MANUFACTURED GAS PRODUCTION PLANT</u>			
Land and Land Rights	13,499	4,476	9,023
Structures and Improvements	673,162	(106,127)	779,289
Liquefied Petroleum Gas Equipment	1,104,414	(564,734)	1,669,148
Total Manufactured Gas Production Plant	1,791,075	(666,385)	2,457,460
Retirement Work in Progress	-	-	-
Total	1,791,075	(666,385)	2,457,460
<u>DISTRIBUTION PLANT</u>			
Land and Land Rights	1,102,585	258,564	844,021
Structures and Improvements	3,118,981	1,133,505	1,985,476
Mains	163,126,608	42,554,945	120,571,663
Compressor Station Equipment	744	(402)	1,146
Meas. and Reg. Station Equipment	10,953,023	5,413,613	5,539,410
Services	108,758,937	38,960,704	69,798,233
Meters	10,383,574	3,548,957	6,834,617
Meter Installation	17,884,650	2,758,425	15,126,225
House Regulators	2,558,929	1,015,856	1,543,073
House Regulator Installations	5,053,536	1,504,552	3,548,984
Industrial Meas. and Reg. Station Equipment	3,045,171	784,930	2,260,241
Other Property on Customers Premises	273,328	113,440	159,888
Total Distribution Plant	326,260,066	98,047,089	228,212,977
Retirement Work in Progress	-	(20,477)	20,477
Total	\$326,260,066	\$98,026,612	\$228,233,454

ORANGE AND ROCKLAND UTILITIES, INC.
Net Book Value of Gas Plant in Service
December 31, 2004

Exhibit G-1
Schedule 3
Page 2 of 10

	Gas Plant in Service	Accumulated Provision for Depreciation & Amortization	Net Book Value
GENERAL PLANT			
Land and Land Rights	\$2,737	-	\$2,737
Structures and Improvements	168,697	602	168,095
Office Furniture & Equipment	526,028	338,861	187,167
Transportation Equipment	1,793,569	1,297,881	495,688
Stores Equipment	6,665	3,232	3,433
Tools, Shop & Garage Equipment	2,202,570	695,486	1,507,084
Laboratory Equipment	508,059	30,746	477,313
Power Operated Equipment	804,549	350,429	454,120
Communication Equipment	372,095	135,702	236,393
Miscellaneous Equipment	109,116	33,602	75,514
Total General Plant	<u>6,494,085</u>	<u>2,886,541</u>	<u>3,607,544</u>
Retirement Work in Progress	<u>-</u>	<u>-</u>	<u>-</u>
Total	<u>6,494,085</u>	<u>2,886,541</u>	<u>3,607,544</u>
Unallocated Reserve (Case 99-G-1695)	<u>-</u>	<u>5,574,786</u>	<u>(5,574,786)</u>
Total	<u><u>\$334,566,052</u></u>	<u><u>\$105,828,487</u></u>	<u><u>\$228,737,565</u></u>

ORANGE AND ROCKLAND UTILITIES, INC.
Net Book Value of Gas Plant in Service
December 31, 2005

Exhibit G-1
Schedule 3
Page 3 of 10

	Gas Plant in Service	Accumulated Provision for Depreciation & Amortization	Net Book Value
<u>INTANGIBLE PLANT</u>			
Franchises and Consents	\$20,826	\$6,933	\$13,893
Misc Intangible Plan	<u>3,326,278</u>	<u>309,237</u>	<u>3,017,041</u>
Total Intangible Plant	<u>3,347,104</u>	<u>316,170</u>	<u>3,030,934</u>
<u>MANUFACTURED GAS PRODUCTION PLANT</u>			
Land and Land Rights	13,499	4,734	8,766
Structures and Improvements	674,516	(83,010)	757,526
Liquefied Petroleum Gas Equipment	<u>1,102,966</u>	<u>(518,382)</u>	<u>1,621,348</u>
Total Manufactured Gas Production Plant	<u>1,790,982</u>	<u>(596,658)</u>	<u>2,387,640</u>
Retirement Work in Progress	<u>-</u>	<u>(1,790)</u>	<u>1,790</u>
Total	<u>1,790,982</u>	<u>(598,448)</u>	<u>2,389,430</u>
<u>DISTRIBUTION PLANT</u>			
Land and Land Rights	1,102,585	270,702	831,883
Structures and Improvements	3,113,072	1,218,477	1,894,596
Mains	173,759,312	45,089,927	128,669,386
Compressor Station Equipment	744	(379)	1,124
Meas. and Reg. Station Equipment	11,622,749	5,250,621	6,372,128
Services	115,638,024	41,781,082	73,856,943
Meters	11,090,198	3,785,394	7,304,804
Meter Installation	19,489,174	3,065,526	16,423,649
House Regulators	2,626,970	1,067,909	1,559,061
House Regulator Installations	5,213,947	1,596,559	3,617,388
Industrial Meas. and Reg. Station Equipment	3,252,628	810,008	2,442,620
Other Property on Customers Premises	<u>267,617</u>	<u>113,915</u>	<u>153,702</u>
Total Distribution Plant	<u>347,177,022</u>	<u>104,049,740</u>	<u>243,127,281</u>
Retirement Work in Progress	<u>-</u>	<u>(19,716)</u>	<u>19,716</u>
Total	<u>\$347,177,022</u>	<u>\$104,030,025</u>	<u>\$243,146,997</u>

ORANGE AND ROCKLAND UTILITIES, INC.
Net Book Value of Gas Plant in Service
December 31, 2005

Exhibit G-1
Schedule 3
Page 4 of 10

	Gas Plant in Service	Accumulated Provision for Depreciation & Amortization	Net Book Value
<u>GENERAL PLANT</u>			
Land and Land Rights	\$2,737	-	\$2,737
Structures and Improvements	168,697	4,314	164,383
Office Furniture & Equipment	427,097	225,469	201,628
Transportation Equipment	2,555,607	1,493,420	1,062,187
Stores Equipment	7,312	3,453	3,859
Tools, Shop & Garage Equipment	2,302,931	791,044	1,511,887
Laboratory Equipment	551,808	33,789	518,019
Power Operated Equipment	825,771	390,781	434,990
Communication Equipment	237,923	14,585	223,338
Miscellaneous Equipmen	<u>108,736</u>	<u>30,092</u>	<u>78,643</u>
Total General Plant	<u>7,188,620</u>	<u>2,986,947</u>	<u>4,201,673</u>
 Retirement Work in Progress	 <u>-</u>	 <u>-</u>	 <u>-</u>
 Total	 <u>7,188,620</u>	 <u>2,986,947</u>	 <u>4,201,673</u>
 Unallocated Reserve (Case 99-G-1695	 <u>-</u>	 <u>5,027,786</u>	 <u>(5,027,786)</u>
 Total	 <u><u>\$359,503,727</u></u>	 <u><u>\$111,762,480</u></u>	 <u><u>\$247,741,247</u></u>

ORANGE AND ROCKLAND UTILITIES, INC.
Net Book Value of Gas Plant in Service
December 31, 2006

Exhibit G-1
Schedule 3
Page 5 of 10

	Gas Plant in Service	Accumulated Provision for Depreciation & Amortization	Net Book Value
<u>INTANGIBLE PLANT</u>			
Franchises and Consents	\$20,826	\$6,933	\$13,893
Misc Intangible Plan	<u>3,614,779</u>	<u>1,013,104</u>	<u>\$2,601,675</u>
Total Intangible Plant	<u>3,635,605</u>	<u>1,020,037</u>	<u>2,615,568</u>
<u>MANUFACTURED GAS PRODUCTION PLANT</u>			
Land and Land Rights	13,499	4,991	8,508
Structures and Improvements	674,516	(59,874)	734,390
Liquefied Petroleum Gas Equipment	<u>1,110,385</u>	<u>(480,163)</u>	<u>1,590,548</u>
Total Manufactured Gas Production Plant	<u>1,798,400</u>	<u>(535,046)</u>	<u>2,333,446</u>
Retirement Work in Progress	<u>-</u>	<u>-</u>	<u>-</u>
Total	<u>1,798,400</u>	<u>(535,046)</u>	<u>2,333,446</u>
<u>DISTRIBUTION PLANT</u>			
Land and Land Rights	1,250,678	284,283	966,395
Structures and Improvements	3,453,852	1,283,594	2,170,258
Mains	185,567,925	47,637,961	137,929,965
Compressor Station Equipment	744	(357)	1,101
Meas. and Reg. Station Equipment	12,884,857	5,384,380	7,500,477
Services	123,177,817	44,732,762	78,445,054
Meters	11,448,520	3,693,836	7,754,684
Meter Installation	20,929,274	3,267,207	17,662,067
House Regulators	2,680,651	1,083,116	1,597,534
House Regulator Installations	5,386,019	1,688,792	3,697,227
Industrial Meas. and Reg. Station Equipment	3,410,964	891,738	2,519,226
Other Property on Customers Premises	<u>265,003</u>	<u>115,875</u>	<u>149,127</u>
Total Distribution Plant	<u>370,456,303</u>	<u>110,063,186</u>	<u>260,393,117</u>
Retirement Work in Progress	<u>-</u>	<u>(13,763)</u>	<u>13,763</u>
Total	<u>\$370,456,303</u>	<u>\$110,049,424</u>	<u>\$260,406,879</u>

ORANGE AND ROCKLAND UTILITIES, INC.
Net Book Value of Gas Plant in Service
December 31, 2006

Exhibit G-1
Schedule 3
Page 6 of 10

	Gas Plant in Service	Accumulated Provision for Depreciation & Amortization	Net Book Value
<u>GENERAL PLANT</u>			
Land and Land Rights	\$2,737	-	\$2,737
Structures and Improvements	168,697	8,025	160,672
Office Furniture & Equipment	406,661	201,395	205,267
Transportation Equipment	2,639,140	1,031,832	1,607,308
Stores Equipment	7,312	3,697	3,615
Tools, Shop & Garage Equipment	2,370,896	844,280	1,526,615
Laboratory Equipment	606,099	52,550	553,549
Power Operated Equipment	1,118,866	366,818	752,049
Communication Equipment	251,268	23,367	227,901
Miscellaneous Equipmen	<u>103,932</u>	<u>29,575</u>	<u>74,358</u>
Total General Plant	<u>7,675,610</u>	<u>2,561,538</u>	<u>5,114,071</u>
 Retirement Work in Progress	 <u>-</u>	 <u>-</u>	 <u>-</u>
 Total	 <u>7,675,610</u>	 <u>2,561,538</u>	 <u>5,114,071</u>
 Cost of Removal Reserve	 -		 0
Unallocated Reserve (Case 99-G-1695)	<u>-</u>	<u>4,480,786</u>	<u>(4,480,786)</u>
 Total	 <u><u>\$383,565,918</u></u>	 <u><u>\$117,576,739</u></u>	 <u><u>\$265,989,179</u></u>

ORANGE AND ROCKLAND UTILITIES, INC.
Net Book Value of Gas Plant in Service
December 31, 2007

Exhibit G-1
Schedule 3
Page 7 of 10

	Gas Plant in Service	Accumulated Provision for Depreciation & Amortization	Net Book Value
<u>INTANGIBLE PLANT</u>			
Franchises and Consents	\$20,826	\$6,933	\$13,893
Misc Intangible Plan	<u>3,550,848</u>	<u>1,727,451</u>	<u>1,823,397</u>
Total Intangible Plant	<u>3,571,674</u>	<u>1,734,385</u>	<u>1,837,290</u>
<u>MANUFACTURED GAS PRODUCTION PLANT</u>			
Land and Land Rights	13,499	5,249	8,251
Structures and Improvements	690,200	(36,694)	726,893
Liquefied Petroleum Gas Equipment	<u>1,119,765</u>	<u>(442,160)</u>	<u>1,561,924</u>
Total Manufactured Gas Production Plant	<u>1,823,464</u>	<u>(473,605)</u>	<u>2,297,068</u>
Retirement Work in Progress	<u>-</u>	<u>-</u>	<u>-</u>
Total	<u>1,823,464</u>	<u>(473,605)</u>	<u>2,297,068</u>
<u>DISTRIBUTION PLANT</u>			
Land and Land Rights	1,712,554	298,894	1,413,660
Structures and Improvements	3,471,652	1,378,739	2,092,914
Mains	192,602,988	50,379,356	142,223,632
Compressor Station Equipment	744	(335)	1,079
Meas. and Reg. Station Equipment	13,039,451	5,570,825	7,468,627
Services	130,618,371	47,617,458	83,000,914
Meters	11,890,493	3,928,197	7,962,297
Meter Installation	22,204,051	3,618,401	18,585,649
House Regulators	2,719,621	1,105,761	1,613,860
House Regulator Installations	5,573,291	1,784,755	3,788,537
Industrial Meas. and Reg. Station Equipment	3,721,348	980,228	2,741,120
Other Property on Customers Premises	<u>265,003</u>	<u>129,126</u>	<u>135,877</u>
Total Distribution Plant	<u>387,819,568</u>	<u>116,791,403</u>	<u>271,028,165</u>
Retirement Work in Progress	<u>-</u>	<u>(146,210)</u>	<u>146,210</u>
Total	<u>\$387,819,568</u>	<u>\$116,645,193</u>	<u>\$271,174,375</u>

ORANGE AND ROCKLAND UTILITIES, INC.
Net Book Value of Gas Plant in Service
December 31, 2007

Exhibit G-1
Schedule 3
Page 8 of 10

	Gas Plant in Service	Accumulated Provision for Depreciation & Amortization	Net Book Value
<u>GENERAL PLANT</u>			
Land and Land Rights	\$2,737	-	\$2,737
Structures and Improvements	285,634	11,612	274,023
Office Furniture & Equipment	625,910	123,547	502,363
Transportation Equipment	3,201,991	1,132,968	2,069,023
Stores Equipment	17,522	4,734	12,788
Tools, Shop & Garage Equipment	2,588,764	912,620	1,676,144
Laboratory Equipment	601,794	54,706	547,087
Power Operated Equipment	944,059	278,802	665,257
Communication Equipment	242,336	(190,006)	432,342
Miscellaneous Equipmen	<u>130,425</u>	<u>22,804</u>	<u>107,621</u>
Total General Plant	<u>8,641,171</u>	<u>2,351,787</u>	<u>6,289,385</u>
 Retirement Work in Progress	 <u>-</u>	 <u>-</u>	 <u>-</u>
 Total	 <u>8,641,171</u>	 <u>2,351,787</u>	 <u>6,289,385</u>
 Unallocated Reserve (Case 99-G-1695	 <u>-</u>	 <u>3,933,786</u>	 <u>(3,933,786)</u>
 Total	 <u><u>\$401,855,877</u></u>	 <u><u>\$124,191,545</u></u>	 <u><u>\$277,664,332</u></u>

ORANGE AND ROCKLAND UTILITIES, INC.
Net Book Value of Gas Plant in Service
June 30, 2008

Exhibit G-1
Schedule 3
Page 9 of 10

	Gas Plant in Service	Accumulated Provision for Depreciation & Amortization	Net Book Value
<u>INTANGIBLE PLANT</u>			
Franchises and Consents	\$20,826	\$6,933	\$13,893
Gas Inspection Management System	-	0	-
Miscellaneous Intangible Plant	5,335,681	2,129,056	3,206,625
	<u>5,356,507</u>	<u>2,135,989</u>	<u>3,220,518</u>
Total Intangible Plant			
<u>MANUFACTURED GAS PRODUCTION PLANT</u>			
Land and Land Rights	13,499	5,377	8,122
Structures and Improvements	690,200	(24,857)	715,057
Liquefied Petroleum Gas Equipment	1,119,765	(417,917)	1,537,682
Total Manufactured Gas Production Plant	1,823,464	(437,397)	2,260,861
	<u>0</u>	<u>(108,375)</u>	<u>108,375</u>
Retirement Work in Progress			
Total	1,823,464	(545,772)	2,369,236
<u>DISTRIBUTION PLANT</u>			
Land and Land Rights	1,822,365	306,199	1,516,166
Structures and Improvements	3,736,978	1,428,890	2,308,088
Mains	194,905,621	52,046,420	142,859,201
Compressor Station Equipment	504	(564)	1,068
Meas. and Reg. Station Equipment	13,144,413	5,553,595	7,590,818
Services	133,906,549	49,281,934	84,624,615
Meters	12,224,766	4,071,622	8,153,144
Meter Installation	22,839,068	3,816,612	19,022,456
House Regulators	2,768,566	1,142,824	1,625,742
House Regulator Installations	5,656,684	1,834,540	3,822,144
Industrial Meas. and Reg. Station Equipment	3,783,360	1,027,693	2,755,667
Other Property on Customers Premises	240,606	107,578	133,028
Total Distribution Plant	395,029,480	120,617,343	274,412,137
	<u>-</u>	<u>-</u>	<u>-</u>
Retirement Work in Progress			
Total	\$395,029,480	\$120,617,343	\$274,412,137

ORANGE AND ROCKLAND UTILITIES, INC.
Net Book Value of Gas Plant in Service
June 30, 2008

Exhibit G-1
Schedule 3
Page 10 of 10

	Gas Plant in Service	Accumulated Provision for Depreciation & Amortization	Net Book Value
<u>GENERAL PLANT</u>			
Land and Land Rights	\$2,737	-	\$2,737
Structures and Improvements	291,961	14,788	277,173
Office Furniture & Equipment	749,602	154,733	594,869
Transportation Equipment	3,564,499	1,300,259	2,264,240
Stores Equipment	17,522	5,026	12,496
Tools, Shop & Garage Equipment	2,649,749	976,745	1,673,004
Laboratory Equipment	604,416	64,755	539,661
Power Operated Equipment	1,038,990	303,986	735,004
Communication Equipment	239,394	(188,131)	427,525
Miscellaneous Equipment	144,988	23,997	120,991
Total General Plant	<u>9,303,858</u>	<u>2,656,158</u>	<u>6,647,700</u>
 Retirement Work in Progress	 -	 (57,762)	 57,762
 Total	 <u>9,303,858</u>	 <u>2,598,396</u>	 <u>6,705,462</u>
 Unallocated Reserve (Case 99-G-1695)	 -	 3,660,286	 (3,660,286)
 Total	 <u><u>\$411,513,309</u></u>	 <u><u>\$128,466,242</u></u>	 <u><u>\$283,047,067</u></u>

ORANGE AND ROCKLAND UTILITIES, INC.
Net Book Value of Common Plant in Service
December 31, 2004

	Common Plant in Service	Accumulated Prov. for Deprec. & Amortization	Net Book Value
<u>INTANGIBLE PLANT</u>			
Organization	\$20,916	-	\$20,916
Miscellaneous Intangible Plant - Software	49,119,583	27,281,457	21,838,126
Total Intangible Plant	49,140,499	27,281,457	21,859,042
<u>GENERAL PLANT</u>			
Land and Land Rights	785,996	19,701	766,295
Structures and Improvements	41,541,581	11,761,889	29,779,692
Office Furniture & Equipment	15,166,805	12,991,697	2,175,108
Transportation Equipment	2,262,675	1,163,372	1,099,303
Stores Equipment	324,747	123,258	201,489
Tools, Shop & Garage Equipment	2,088,435	518,135	1,570,300
Laboratory Equipment	911,658	60,402	851,256
Power Operated Equipment	696,945	453,359	243,586
Communication Equipment	6,700,931	4,031,751	2,669,180
Miscellaneous Equipment	1,627,708	468,505	1,159,203
Total General Plant	72,107,481	31,592,069	40,515,412
Retirement Work in Progress	-	(15,606)	15,606
Total	<u>\$121,247,980</u>	<u>\$58,857,920</u>	<u>\$62,390,060</u>

ORANGE AND ROCKLAND UTILITIES, INC.
Net Book Value of Common Plant in Service
December 31, 2005

	Common Plant in Service	Accumulated Prov. for Deprec. & Amortization	Net Book Value
<u>INTANGIBLE PLANT</u>			
Organization	\$20,916	-	\$20,916
Miscellaneous Intangible Plant - Software	<u>49,813,100</u>	<u>31,723,138</u>	<u>18,089,962</u>
Total Intangible Plant	<u>49,834,016</u>	<u>31,723,138</u>	<u>18,110,879</u>
<u>GENERAL PLANT</u>			
Land and Land Rights	785,996	20,366	765,630
Structures and Improvements	42,326,003	11,562,351	30,763,651
Office Furniture & Equipment	14,421,610	11,975,064	2,446,546
Transportation Equipment	2,975,438	1,417,448	1,557,990
Stores Equipment	434,599	99,073	335,527
Tools, Shop & Garage Equipment	2,142,443	588,555	1,553,888
Laboratory Equipment	914,304	90,347	823,957
Power Operated Equipment	626,653	377,476	249,177
Communication Equipment	7,489,040	4,598,816	2,890,224
Miscellaneous Equipment	<u>1,673,898</u>	<u>492,806</u>	<u>1,181,092</u>
Total General Plant	<u>73,789,983</u>	<u>31,222,302</u>	<u>42,567,681</u>
Retirement Work in Progress	<u>-</u>	<u>(2,000)</u>	<u>2,000</u>
Total	<u>\$123,623,999</u>	<u>\$62,943,439</u>	<u>\$60,680,559</u>

ORANGE AND ROCKLAND UTILITIES, INC.
Net Book Value of Common Plant in Service
December 31, 2006

	Common Plant in Service	Accumulated Prov. for Deprec. & Amortization	Net Book Value
<u>INTANGIBLE PLANT</u>			
Organization	\$20,916	-	\$20,916
Miscellaneous Intangible Plant - Software	<u>49,820,680</u>	<u>34,504,815</u>	<u>15,315,865</u>
Total Intangible Plant	<u>49,841,596</u>	<u>34,504,815</u>	<u>15,336,781</u>
<u>GENERAL PLANT</u>			
Land and Land Rights	785,996	21,031	764,965
Structures and Improvements	43,635,057	11,939,691	31,695,367
Office Furniture & Equipment	14,020,439	12,306,917	1,713,522
Transportation Equipment	2,572,305	1,160,536	1,411,769
Stores Equipment	443,015	59,453	383,562
Tools, Shop & Garage Equipment	2,316,043	593,375	1,722,668
Laboratory Equipment	923,130	120,892	802,239
Power Operated Equipment	420,066	333,539	86,528
Communication Equipment	8,233,260	5,363,113	2,870,147
Miscellaneous Equipment	<u>1,732,827</u>	<u>450,350</u>	<u>1,282,477</u>
Total General Plant	<u>75,082,139</u>	<u>32,348,897</u>	<u>42,733,242</u>
Cost of Removal	-	-	-
Retirement Work in Progress	<u>-</u>	<u>(15,000)</u>	<u>15,000</u>
Total	<u>\$124,923,735</u>	<u>\$66,838,712</u>	<u>\$58,085,023</u>

ORANGE AND ROCKLAND UTILITIES, INC.
Net Book Value of Common Plant in Service
December 31, 2007

	Common Plant in Service	Accumulated Prov. for Deprec. & Amortization	Net Book Value
<u>INTANGIBLE PLANT</u>			
Organization	\$20,916	-	\$20,916
Miscellaneous Intangible Plant - Software	<u>51,834,340</u>	<u>36,916,907</u>	<u>14,917,433</u>
Total Intangible Plant	<u>51,855,256</u>	<u>36,916,907</u>	<u>14,938,349</u>
<u>GENERAL PLANT</u>			
Land and Land Rights	785,996	21,695	764,300
Structures and Improvements	49,261,188	11,899,580	37,361,608
Office Furniture & Equipment	11,099,133	9,726,586	1,372,547
Transportation Equipment	2,740,391	1,048,005	1,692,386
Stores Equipment	454,061	71,161	382,899
Tools, Shop & Garage Equipment	2,283,850	612,091	1,671,759
Laboratory Equipment	1,005,668	153,203	852,465
Power Operated Equipment	484,768	318,717	166,051
Communication Equipment	8,247,569	5,837,244	2,410,324
Miscellaneous Equipment	<u>1,837,390</u>	<u>490,722</u>	<u>1,346,668</u>
Total General Plant	<u>78,200,013</u>	<u>30,179,005</u>	<u>48,021,008</u>
Retirement Work in Progress	<u>-</u>	<u>(62,512)</u>	<u>62,512</u>
Total	<u>\$130,055,269</u>	<u>\$67,033,400</u>	<u>\$63,021,869</u>

ORANGE AND ROCKLAND UTILITIES, INC.
Net Book Value of Common Plant in Service
June 30, 2008

	Common Plant in Service	Accumulated Prov. for Deprec. & Amortization	Net Book Value
<u>INTANGIBLE PLANT</u>			
Organization	\$20,916	-	\$20,916
Miscellaneous Intangible Plant - Software	51,995,132	38,501,881	13,493,251
Total Intangible Plant	52,016,048	38,501,881	13,514,167
<u>GENERAL PLANT</u>			
Land and Land Rights	785,996	22,028	763,968
Structures and Improvements	49,902,600	12,109,703	37,792,897
Common Utility Plant- Leased Equip.-DARK FIBER	2,029,543	-	2,029,543
Office Furniture & Equipment	11,699,100	10,013,886	1,685,214
Transportation Equipment	2,960,449	1,209,223	1,751,226
Stores Equipment	280,375	60,431	219,944
Tools, Shop & Garage Equipment	2,315,344	658,372	1,656,972
Laboratory Equipment	998,654	160,817	837,837
Power Operated Equipment	746,842	338,342	408,500
Communication Equipment	8,457,083	6,245,083	2,212,000
Miscellaneous Equipment	1,866,582	514,625	1,351,957
Total General Plant	82,042,568	31,332,510	50,710,058
Retirement Work in Progress	-	51,220	(51,220)
Total	<u>\$134,058,616</u>	<u>69,885,609</u>	<u>64,173,007</u>

ORANGE AND ROCKLAND UTILITIES, INC.
Gas Plant in Service and Average Cost
Per Customer

<u>Date</u>	<u>Gas Plant In Service At End of Period</u>	<u>Number of Gas Customers At End of Period</u>	<u>Average Gas Plant Per Customer</u>
December 31, 2004	\$ 334,566,052	123,077	\$ 2,718
December 31, 2005	359,503,727	124,098	2,897
December 31, 2006	383,565,918	125,223	3,063
December 31, 2007	401,855,877	126,200	3,184
June 30, 2008	411,513,309	126,321	3,258

ORANGE AND ROCKLAND UTILITIES, INC.
Statement of Income for Year Ended December 31, 2005

Exhibit G-1
Schedule 6
Page 1 of 4

	Company Total	Electric Department	Gas Department
<u>Utility Operating Income</u>			
Operating Revenue	\$680,412,538	\$452,025,804	\$228,386,734
Operating Expenses:			
Operation and Maintenance	529,308,812	343,795,471	185,513,341
Depreciation Expense	26,693,437	18,654,420	8,039,017
Amortization of Other Limited Term Plant	4,844,400	3,466,375	1,378,026
Amortization of Property Losses	-	-	-
Taxes Other than Income Taxes	38,293,489	27,134,878	11,158,611
Income Taxes	20,472,312	18,173,254	2,299,058
Provision for Deferred Income Taxes	15,597,671	10,115,763	5,481,908
Provision for Deferred Income Taxes - Cr.	(12,545,315)	(10,980,747)	(1,564,568)
Investment Tax Credit Adjustments	-	-	-
Total Operating Expenses	622,664,806	410,359,414	212,305,392
Total Utility Operating Income	\$57,747,731	\$41,666,390	\$16,081,341
<u>Other Income</u>			
Equity in Earnings of Subsidiary Companies	11,017,695		
Investment Income	806,851		
Allowance for Funds Used During Construction	45,551		
Miscellaneous Non-Operating Income	807,170		
Total Other Income	12,677,268		
<u>Other Income Deductions</u>			
Miscellaneous Income Deductions	392,365		
Total Other Income Deductions	392,365		
<u>Taxes - Other Income Deductions</u>			
Taxes Other Than Income Taxes	76,305		
Income Taxes	441,455		
Deferred Income Taxes	3,671		
Investment Tax Credit Adjustment	(365,785)		
Total Taxes - Other Income Deductions	155,646		
Net Other Income and Deductions	12,129,256		
<u>Interest Charges</u>			
Interest on Long Term Debt	18,483,822		
Amortization of Debt Discount & Expense	648,417		
Amortization of Premium on Debt			
Interest on Debt to Associated Companies			
Allowance for Borrowed Funds	(537,956)		
Other Interest Expense	1,885,359		
Total Interest Charges	20,479,641		
Net Income	\$49,397,347		

ORANGE AND ROCKLAND UTILITIES, INC.
Statement of Income for Year Ended December 31, 2006

Exhibit G-1
Schedule 6
Page 2 of 4

	Company Total	Electric Department	Gas Department
<u>Utility Operating Income</u>			
Operating Revenue	\$663,510,045	\$427,711,673	\$235,798,372
Operating Expenses:			
Operation and Maintenance	520,059,877	326,610,525	193,449,352
Depreciation Expense	28,594,893	19,990,711	8,604,182
Amortization of Other Limited Term Plant	3,568,816	2,194,690	1,374,126
Amortization of Property Losses	-	-	-
Taxes Other than Income Taxes	38,564,150	26,638,714	11,925,436
Income Taxes	7,129,791	3,128,205	4,001,586
Provision for Deferred Income Taxes	12,188,951	11,196,410	992,541
Provision for Deferred Income Taxes - Cr.	(1,804,039)	(1,498,194)	(305,845)
Gain / Loss on Disposition of Utility Plants	-	-	-
Investment Tax Credit Adjustments	-	-	-
Total Operating Expenses	608,302,440	388,261,061	220,041,379
Total Utility Operating Income	\$55,207,605	\$39,450,612	\$15,756,993
<u>Other Income</u>			
Equity in Earnings of Subsidiary Companies	13,228,330		
Investment Income	1,832,935		
Allowance for Funds Used During Construction	-		
Miscellaneous Non-Operating Income	1,130,591		
Total Other Income	16,191,855		
<u>Other Income Deductions</u>			
Miscellaneous Income Deductions	323,175		
Total Other Income Deductions	323,175		
<u>Taxes - Other Income Deductions</u>			
Taxes Other Than Income Taxes	63,658		
Income Taxes	912,309		
Deferred Income Taxes	(419)		
Investment Tax Credit Adjustment	(303,545)		
Total Taxes - Other Income Deductions	672,003		
Net Other Income and Deductions	15,196,677		
<u>Interest Charges</u>			
Interest on Long Term Debt	20,398,888		
Amortization of Debt Discount & Expense	677,446		
Amortization of Premium on Debt	-		
Interest on Debt to Associated Companies	-		
Allowance for Borrowed Funds	(1,024,434)		
Other Interest Expense	4,726,798		
Total Interest Charges	24,778,698		
Net Income	\$45,625,585		

ORANGE AND ROCKLAND UTILITIES, INC.
Statement of Income for Year Ended December 31, 2007

Exhibit G-1
Schedule 6
Page 3 of 4

	Company Total	Electric Department	Gas Department
<u>Utility Operating Income</u>			
Operating Revenue	\$749,704,707	\$484,436,146	\$265,268,561
Operating Expenses:			
Operation and Maintenance	604,641,665	387,752,170	216,889,494
Depreciation Expense	30,180,025	21,017,297	9,162,728
Amortization of Other Limited Term Plant	4,078,171	2,657,457	1,420,714
Amortization of Property Losses	-	-	-
Taxes Other than Income Taxes	33,453,063	22,621,019	10,832,045
Income Taxes	4,526,708	(1,375,255)	5,901,963
Provision for Deferred Income Taxes	6,620,316	2,116,897	4,503,419
Provision for Deferred Income Taxes - Cr.	3,720,401	8,848,743	(5,128,342)
Gain / Loss on Disposition of Utility Plants	-	-	-
Investment Tax Credit Adjustments	-	-	-
Total Operating Expenses	687,220,349	443,638,327	243,582,021
Total Utility Operating Income	\$62,484,359	\$40,797,819	\$21,686,540
<u>Other Income</u>			
Equity in Earnings of Subsidiary Companies	14,540,321		
Investment Income	1,063,025		
Allowance for Funds Used During Construction	107,305		
Miscellaneous Adjustments	(160)		
Miscellaneous Non-Operating Income	(656,013)		
Total Other Income	15,054,478		
<u>Other Income Deductions</u>			
Miscellaneous Income Deductions	333,405		
Total Other Income Deductions	333,405		
<u>Taxes - Other Income Deductions</u>			
Taxes Other Than Income Taxes	541,833		
Income Taxes	623,876		
Deferred Income Taxes	(1,407,151)		
Investment Tax Credit Adjustment	(311,130)		
Total Taxes - Other Income Deductions	(552,572)		
Net Other Income and Deductions	15,273,644		
<u>Interest Charges</u>			
Interest on Long Term Debt	23,672,174		
Amortization of Debt Discount & Expense	725,059		
Amortization of Premium on Debt	-		
Interest on Debt to Associated Companies	-		
Allowance for Borrowed Funds	(633,826)		
Other Interest Expense	7,549,760		
Total Interest Charges	31,313,166		
Net Income	\$46,444,837		

ORANGE AND ROCKLAND UTILITIES, INC.
Statement of Income for the Twelve Months Ended June 30, 2008

Exhibit G-1
Schedule 6
Page 4 of 4

	Company Total	Electric Department	Gas Department
<u>Utility Operating Income</u>			
Operating Revenue	\$758,644,341	\$503,671,918	\$254,972,423
Operating Expenses:			
Operation and Maintenance	628,826,675	419,116,317	209,710,357
Depreciation Expense	30,774,074	21,373,123	9,400,951
Amortization of Other Limited Term Plant	4,506,675	2,999,022	1,507,653
Amortization of Property Losses	-	-	-
Taxes Other than Income Taxes	34,881,203	23,027,636	11,853,567
Income Taxes	(1,533,143)	(7,232,570)	5,699,427
Provision for Deferred Income Taxes	8,558,548	6,423,365	2,135,183
Provision for Deferred Income Taxes - Cr.	1,798,853	5,976,496	(4,177,643)
Gain / Loss on Disposition of Utility Plants	-	-	-
Investment Tax Credit Adjustments	-	-	-
Total Operating Expenses	707,812,884	471,683,389	236,129,496
Total Utility Operating Income	\$50,831,457	\$31,988,529	\$18,842,927
<u>Other Income</u>			
Equity in Earnings of Subsidiary Companies	13,358,725		
Investment Income	2,579,406		
Allowance for Funds Used During Construction	107,305		
Miscellaneous Adjustments	(160)		
Miscellaneous Non-Operating Income	(134,539)		
Total Other Income	15,910,737		
<u>Other Income Deductions</u>			
Miscellaneous Income Deductions	341,752		
Total Other Income Deductions	341,752		
<u>Taxes - Other Income Deductions</u>			
Taxes Other Than Income Taxes	396,910		
Income Taxes	989,778		
Deferred Income Taxes	(468,416)		
Investment Tax Credit Adjustment	(314,923)		
Total Taxes - Other Income Deductions	603,349		
Net Other Income and Deductions	14,965,636		
<u>Interest Charges</u>			
Interest on Long Term Debt	24,000,316		
Amortization of Debt Discount & Expense	725,059		
Amortization of Premium on Debt	-		
Interest on Debt to Associated Companies	-		
Allowance for Borrowed Funds	(953,557)		
Other Interest Expense	5,653,852		
Total Interest Charges	29,425,671		
Net Income	\$36,371,422		

ORANGE AND ROCKLAND UTILITIES, INC.
Gas Operation and Maintenance Expenses
For the Twelve Months Ended

Exhibit G-1
Schedule 7
Page 1 of 3

	Dec. 31, 2005	Dec. 31, 2006	Dec. 31, 2007	June 30, 2008
<u>Production Expenses</u>				
<u>Manufactured Gas Production</u>				
Liquefied Petroleum Gas Expenses	\$95,102	\$113,040	\$117,549	\$108,357
<u>Maintenance</u>				
Maintenance Supervision and Engineering				
Maintenance of Structures	22,609	16,874	12,726	10,156
Maintenance of Production Equipment	44,351	53,416	49,450	56,174
Total Maintenance	66,960	70,290	62,176	66,330
Total Manufactured Gas Production	162,063	183,330	179,725	174,687
<u>Other Gas Supply Expense</u>				
<u>Operation</u>				
Natural Gas Field Line Purchases	-	-	-	-
Natural Gas Transmission Line Purchases	-	-	-	-
Natural Gas City Gate Purchases	178,558,212	158,142,010	167,744,297	180,102,303
Other Gas Purchases	-	-	-	-
	178,558,212	158,142,010	167,744,297	180,102,303
Exchange Gas	-	-	-	-
Purchased Gas Expenses	288,624	351,016	396,921	466,014
Pipeline Supplier Refund	-	(177)	18,255	-
Gas Withdrawn from Storage - Debit	30,215,514	17,600,630	34,596,719	19,963,487
Gas Delivered to Storage - Credit	(66,188,129)	(34,736,072)	(37,464,237)	(49,116,841)
Deferred Gas Costs	-	9,488,709	4,520,124	10,985,707
Other Gas Supply Expenses	18,151	(1,043,844)	(3,227,485)	(4,935,194)
Total Operation	142,892,372	149,802,272	166,584,594	157,465,474
Joint Expenses - Credit				
Total Other Gas Supply Expenses	142,892,372	149,802,272	166,584,594	157,465,474
Total Production Expenses	143,054,435	149,985,602	166,764,319	157,640,161
<u>Underground Storage Expenses</u>				
Storage Well Royalties	-	-	-	-
Total Underground Storage Expenses	-	-	-	-

ORANGE AND ROCKLAND UTILITIES, INC.
Gas Operation and Maintenance Expenses
For the Twelve Months Ended

Exhibit G-1
Schedule 7
Page 2 of 3

	Dec. 31, 2005	Dec. 31, 2006	Dec. 31, 2007	June 30, 2008
<u>Transmission Expenses</u>				
Transmission and Compression of Gas by Others	278,010	100,575	(63,627)	-
Total Transmission Expenses	278,010	100,575	(63,627)	-
<u>Distribution Expenses</u>				
<u>Operation</u>				
Operation Supervision and Engineering	4,014,193	4,308,710	4,335,541	4,193,960
Distribution Load Dispatching	479,286	510,281	515,606	572,411
Mains and Services Expenses	1,679,767	1,742,455	2,493,704	2,665,435
Measuring and Regulating Station Expenses	647,910	469,185	447,695	453,685
Measuring and Reg. Station Expenses - Ind.	162,873	162,523	182,102	216,850
Meter and House Regulator Expenses	460,587	280,663	373,576	399,519
Customer Installation Expenses	1,741,447	1,653,131	1,836,820	1,977,769
Other Expenses	930,843	1,222,755	603,965	745,015
Rents	22,017	24,671	19,480	19,258
Total Operation	10,138,923	10,374,374	10,808,488	11,243,902
<u>Maintenance</u>				
Maintenance Supervision and Engineering	408,182	414,611	408,443	406,478
Maintenance of Mains	3,300,809	3,192,727	3,649,014	3,718,814
Maintenance of Meas. and Reg. Station Equip.- Gen	252,196	300,833	343,795	286,319
Maint. of Meas. and Reg. Station Equip. - Ind.	123,041	151,844	143,296	157,539
Maintenance of Services	1,268,248	1,719,834	1,632,685	1,782,563
Maintenance of Meter and House Regulators	535,132	554,940	529,938	526,182
Total Maintenance	5,887,608	6,334,788	6,707,172	6,877,894
Total Distribution Expenses	16,026,531	16,709,162	17,515,660	18,121,796
<u>Customer Accounts Expense</u>				
<u>Operation</u>				
Supervision	2,188	494	338	308
Meter Reading Expenses	1,104,025	1,111,322	1,114,571	1,144,052
Customer Records and Collection Expenses	3,699,934	3,627,493	3,694,326	3,681,851
Uncollectible Accounts	766,325	787,309	1,090,344	1,271,459
Miscellaneous Customer Accounts Expenses	132,573	122,384	88,305	114,708
Total Customer Accounts Expenses	5,705,046	5,649,002	5,987,885	6,212,377
<u>Customer Service Expenses</u>				
<u>Operation</u>				
Supervision	130,695	150,152	281,860	277,028
Customer Assistance Expenses	856,406	862,480	912,369	969,326
DSM/HIECA/ULIEEP Expenses	228,337	4,712	741,000	741,000
Informational Advertising Expenses	43,987	57,047	3,166	3,641
Miscellaneous Customer Service Expenses	31,821	9,820	1,425	581
Rents	1,507	(1,404)	211	310
Total Customer Service Expenses	1,292,754	1,082,807	1,940,031	1,991,886

ORANGE AND ROCKLAND UTILITIES, INC.
Gas Operation and Maintenance Expenses
For the Twelve Months Ended

Exhibit G-1
Schedule 7
Page 3 of 3

	Dec. 31, 2005	Dec. 31, 2006	Dec. 31, 2007	June 30, 2008
<u>Sales Promotion Expenses</u>				
<u>Operation</u>				
Demonstration and Selling Expenses	799	3,676	-	2
Promotional Advertising Expenses	211,367	167,645	192	192
Total Sales Promotion Expenses	212,166	171,321	192	194
<u>Administrative and General Expenses</u>				
<u>Operation</u>				
Administrative and General Salaries	1,966,127	2,015,866	1,927,913	2,087,461
Office Supplies and Expense	1,024,172	1,025,076	1,027,534	1,047,800
Administrative Expenses Transferred - Cr.	3,300,828	3,198,423	3,395,077	3,411,785
Outside Services Employed	156,147	201,107	304,030	314,379
Property Insurance	68,200	14,983	107,855	110,844
Other Insurance	-	-	120	120
Injuries and Damages	913,436	1,203,998	2,317,491	2,487,307
Employee Pensions and Benefits	10,688,120	11,001,780	14,705,712	15,380,614
Regulatory Commission Expenses	519,507	512,745	582,080	639,360
Duplicate Charges - Cr.	(512,713)	(470,372)	(443,864)	(537,142)
Instit/Goodwill Adv Expenses	54,059	119,424	3,290	2,944
R&D Expenses	295,000	174,477	219,137	207,640
Miscellaneous General Expenses	8,934	411,606	268,575	242,382
Corporate and Fiscal Expenses	191,203	125,500	80,526	85,536
General Rents	15,373	11,424	15,177	16,884
Expenses of Data Processing Equipment	147,191	110,851	134,197	131,340
Total Operation	18,835,585	19,656,888	24,644,850	25,629,255
<u>Maintenance</u>				
Maintenance of General Plant	108,815	93,994	100,184	114,688
Total Administrative and General Expenses	18,944,399	19,750,883	24,745,034	25,743,942
Total Operation and Maintenance	\$185,513,341	\$193,449,352	\$216,889,494	\$209,710,357

ORANGE AND ROCKLAND UTILITIES, INC.
Gas Operation and Maintenance Expenses, Taxes and Depreciation
Per Thousand Cubic Feet of Gas Sold
For the Twelve Months Ended

	Dec. 31, 2005		Dec. 31, 2006		Dec. 31, 2007		June 30, 2008	
	Amount	Per Mcf Sold	Amount	Per Mcf Sold	Amount	Per Mcf Sold	Amount	Per Mcf Sold
Mcf Sold (000 Omitted)		28,152		18,069		20,295		19,512
Production Expenses								
Manufactured Gas	\$162,063	\$0.0058	\$183,330	\$0.0101	\$179,725	\$0.0089	\$174,687	\$0.0090
Other Gas Supply	142,892,372	5.0757	149,802,272	8.2906	166,584,594	8.2082	157,465,475	8.0702
Total Production	143,054,435	5.0815	149,985,602	8.3007	166,764,319	8.2170	157,640,161	8.0791
Underground Storage	-	-	-	-	-	-	-	-
Transmission	278,010	0.0099	100,575	0.0056	(63,627)	(0.0031)	-	-
Distribution	16,026,531	0.5693	16,709,162	0.9247	17,515,660	0.8631	18,121,797	0.9288
Customer Accounts	5,705,046	0.2027	5,649,002	0.3126	5,987,885	0.2950	6,212,377	0.3184
Customer Service	1,292,754	0.0459	1,082,807	0.0599	1,940,031	0.0956	1,991,886	0.1021
Sales Promotion	212,166	0.0075	171,321	0.0095	192	0.0000	194	0.0000
Administrative & General	18,944,399	0.6729	19,750,883	1.0931	24,745,034	1.2193	25,743,942	1.3194
Total Gas Operation and Maintenance	185,513,341	6.5897	193,449,352	10.7061	216,889,494	10.6868	209,710,357	10.7478
Depreciation and Amortization	9,417,043	0.3345	9,978,308	0.5522	10,583,442	0.5215	10,908,604	0.5591
Taxes Other Than Income Taxes	11,158,611	0.3964	11,925,436	0.6600	10,832,045	0.5337	11,853,567	0.6075
Total Operating Expenses Excl. Federal Income Taxes	\$206,088,995	\$7.3206	\$215,353,096	\$11.9184	\$238,304,981	\$11.7421	\$232,472,528	\$11.9143

ORANGE AND ROCKLAND UTILITIES, INC.

Operating Taxes - Account 408 - Gas

For the Twelve Months Ended

	Dec. 31, 2005	Dec. 31, 2006	Dec. 31, 2007	June 30, 2008
Federal:				
FICA	\$1,052,299	\$959,082	\$911,124	\$984,534
Unemployment	14,887	13,794	13,933	14,357
Total Federal	1,067,186	972,876	925,057	998,890
State:				
Gross Earnings	-	-	-	-
Gross Income	1,435,410	1,984,571	586,240	1,502,653
Excess Dividends	-	-	-	-
Unemployment	13,247	12,286	12,592	12,760
Other	7,373	60,428	57,226	38,433
Total State	1,456,030	2,057,285	656,057	1,553,846
Local:				
Property	8,127,555	8,354,926	8,333,214	8,432,722
1% on Tax Gross Income	507,840	540,348	917,717	868,109
Total Local	8,635,395	8,895,274	9,250,931	9,300,831
Total Operating Taxes	<u>\$11,158,611</u>	<u>\$11,925,436</u>	<u>\$10,832,045</u>	<u>\$11,853,567</u>

ORANGE AND ROCKLAND UTILITIES, INC.
Gas Operating Revenues
Per Thousand Cubic Feet of Gas Sold
For the Twelve Months Ended

	Dec. 31, 2005			Dec. 31, 2006		
	Mcf Sold	Revenues	Revenue Per Mcf	Mcf Sold	Revenues	Revenue Per Mcf
<u>Sales of Gas</u>						
Residential Sales	8,916,786	\$129,621,650	\$14.5368	7,424,889	\$133,284,107	\$17.9510
Commercial and Industrial Sales	5,071,416	55,600,445	10.9635	4,334,225	55,604,806	12.8292
Sales for Resale	1,184,082	1,682,142	1.4206	1,033,301	1,488,767	1.4408
Interdepartmental Sales	-	-	-	-	-	-
Total Sales of Gas	<u>15,172,283</u>	<u>186,904,237</u>	<u>\$12.3188</u>	<u>12,792,415</u>	<u>190,377,680</u>	<u>\$14.8821</u>
<u>Other Operating Revenues</u>						
Miscellaneous Service Revenues		287,077			518,360	
Revenue from Transp. of Gas for Others		35,228,695			34,515,722	
Rent from Gas Property		276,768			417,372	
Other Gas Revenues		<u>5,689,956</u>			<u>9,969,238</u>	
Total Other Operating Revenues		<u>41,482,497</u>			<u>45,420,692</u>	
Total Gas Operating Revenues		<u>\$228,386,734</u>			<u>\$235,798,372</u>	

	Dec. 31, 2007			June 30, 2008		
	Mcf Sold	Revenues	Revenue Per Mcf	Mcf Sold	Revenues	Revenue Per Mcf
<u>Sales of Gas</u>						
Residential Sales	8,371,064	\$150,245,713	\$17.9482	7,800,808	\$139,924,336	\$17.9372
Commercial and Industrial Sales	4,537,784	56,253,005	12.3966	4,387,561	54,654,118	12.4566
Sales for Resale	1,146,014	1,486,534	1.2971	1,126,125	1,533,498	1.3617
Interdepartmental Sales	-	-	-	-	-	-
Total Sales of Gas	<u>14,054,862</u>	<u>207,985,252</u>	<u>\$14.7981</u>	<u>13,314,493</u>	<u>196,111,951</u>	<u>\$14.7292</u>
<u>Other Operating Revenues</u>						
Miscellaneous Service Revenues		288,993			218,750	
Revenue from Transp. of Gas for Others		40,933,657			45,324,433	
Rent from Gas Property		366,128			367,826	
Other Gas Revenues		<u>15,694,531</u>			<u>12,949,463</u>	
Total Other Operating Revenues		<u>57,283,309</u>			<u>58,860,472</u>	
Total Gas Operating Revenues		<u>\$265,268,561</u>			<u>\$254,972,423</u>	

ORANGE AND ROCKLAND UTILITIES, INC.

INDEX OF SCHEDULES

Gas Rate Base
For the Twelve Months Ending
June 30, 2008 and October 31, 2010

<u>SCHEDULE</u>	<u>TITLE OF SCHEDULE</u>	<u>WITNESS</u>
Summary	Gas Rate Base	Accounting Panel
1	Gas Rate Base for the Twelve Months Ended June 30, 2008	"
2	Gas Rate Base for the Twelve Months Ending October 31, 2010	"
3	Gas and Common Plant in Service	"
4	Accumulated Provision for Depreciation of Gas and Common Plant in Service	"
5	Gas Working Capital - Summary	"
6	Cash Working Capital - Gas	"
7	Gas Working Capital - Materials and Supplies	"
8	Gas Working Capital - Prepayments	"
9	Computation of Earnings Base/Capitalization Adjustment	"

EXHIBIT G-2
SUMMARY

ORANGE AND ROCKLAND UTILITIES, INC.

AVERAGE GAS RATE BASE
TWELVE MONTHS ENDED JUNE 30, 2008
AND OCTOBER 31, 2010
(\$000s)

DESCRIPTION	AVERAGE ACTUAL TWELVE MONTHS ENDED JUNE 30, 2008	ADJUSTMENTS TO REFLECT CONDITIONS IN THE RATE YEAR	AVERAGE TWELVE MONTHS ENDED OCTOBER 31, 2010	ADJUSTMENTS TO RATE BASE TWELVE MONTHS ENDED OCTOBER 31, 2010	RATE YEAR RATE BASE FULLY ADJUSTED FOR PROPOSED RATE INCREASE
<u>UTILITY PLANT:</u>					
GAS PLANT IN SERVICE	\$ 399,940	\$ 47,808	\$ 447,748	\$ -	\$ 447,748
GAS PLANT HELD FOR FUTURE USE	210	-	210	-	210
COMMON UTILITY PLANT (GAS ALLOC.)	35,051	5,783	40,834	-	40,834
CWIP NOT TAKING INTEREST	4,300	499	4,799	-	4,799
TOTAL UTILITY PLANT	439,501	54,090	493,591	-	493,591
<u>UTILITY PLANT RESERVES:</u>					
ACC. PROV. FOR DEPRECIATION OF GAS PLANT IN SERVICE (INCLUDES FUTURE USE PLANT)	(124,485)	(24,404)	(148,889)	290	(148,599)
ACC. PROV. FOR DEPRECIATION & AMORTIZATION OF COMMON PLANT	(17,907)	(3,929)	(21,836)	-	(21,836)
TOTAL UTILITY PLANT RESERVES	(142,392)	(28,333)	(170,725)	290	(170,435)
NET PLANT	297,109	25,757	322,866	290	323,156
<u>WORKING CAPITAL REQUIREMENTS:</u>					
O&M EXPENDITURES	5,804	661	6,465	-	6,465
MATERIALS & SUPPLIES	1,353	72	1,425	-	1,425
PREPAYMENTS	3,185	1,468	4,653	-	4,653
DSM - NET OF INCOME TAX	(90)	83	(8)	8	0
R & D EXPENDITURES - NET OF INCOME TAX	(15)	12	(3)	3	0
M.T.A. SURTAX - NET OF INCOME TAX	119	36	155	-	155
RATE CASE COSTS - NET OF INCOME TAX	30	(25)	5	27	32
LOW INCOME PROGRAM - NET OF INCOME TAX	58	(84)	(26)	26	0
CUSTOMER OUTREACH PROGRAM - NET OF INCOME TAX	(237)	(202)	(439)	213	(226)
MGP ENVIRONMENTAL	1,851	1,086	2,937	(353)	2,584
DEFERRED PENSION LIABILITY - ALLOWED	(1,812)	-	(1,812)	1,812	0
CUSTOMER ADVANCES FOR CONSTRUCTION - NET OF INCOME TAX	(41)	1	(40)	-	(40)
GAS PERFORMANCE INCENTIVES - NET OF INCOME TAX	(94)	-	(94)	16	(78)
<u>ACCUM. DEFERRED INCOME TAXES</u>					
ACCUM. DEFERRED FIT - ACRS / ADR	(42,630)	(5,289)	(47,919)	9	(47,910)
ACCUM. DEFERRED FIT - 263(A) CAPITALIZED OVERHEADS	(9,913)	(2,329)	(12,242)	-	(12,242)
ACCUM. DEFERRED SIT	(2,150)	(2,607)	(4,757)	0	(4,757)
ACCUM. FIT ON DEFERRED SIT	760	762	1,522	0	1,522
ACCUMULATED DEFERRED INVESTMENT TAX CREDITS	(1,009)	213	(796)	-	(796)
AVERAGE GAS RATE BASE	\$ 252,277	\$ 19,615	\$ 271,893	\$ 2,051	\$ 273,943

ORANGE AND ROCKLAND UTILITIES, INC.

AVERAGE GAS RATE BASE
TWELVE MONTHS ENDED JUNE 30, 2008
(\$000s)

MONTH ENDED	UTILITY PLANT				UTILITY PLANT RESERVES				C. W. I. P.			
	CIMS / OTHER				CIMS / OTHER				NOT TAKING INTEREST			
	GAS PLANT IN SERVICE	COMMON UTILITY PLANT	COMMON UTILITY PLANT	GAS PLANT HELD FOR FUTURE USE	GAS PLANT IN SERVICE	COMMON UTILITY PLANT	COMMON UTILITY PLANT	CIMS / OTHER COMMON UTILITY PLANT	GAS	COMMON	GAS	TOTAL GAS
JUNE 30, 2007	@1/2	\$194,946	\$10,854	\$6,236	\$105	(\$4,581)	(\$4,330)	(\$4,330)	\$331	\$492	\$823	
JULY 31, 2007		391,637	21,860	12,471	210	(9,234)	(8,720)	(8,720)	1,795	1,044	2,839	
AUGUST 31, 2007		393,778	21,672	12,509	210	(122,331)	(8,897)	(8,781)	1,122	924	2,046	
SEPTEMBER 30, 2007		395,288	21,335	12,509	210	(122,763)	(8,703)	(8,842)	1,588	878	2,466	
OCTOBER 31, 2007		397,342	21,375	12,509	210	(123,200)	(8,736)	(8,904)	2,660	1,390	4,050	
NOVEMBER 30, 2007		399,141	22,431	12,509	210	(123,604)	(8,772)	(8,966)	6,308	841	7,149	
DECEMBER 31, 2007		401,856	22,874	12,507	210	(124,192)	(8,809)	(8,904)	4,335	3,104	7,439	
JANUARY 31, 2008		403,089	22,876	12,507	210	(124,966)	(8,886)	(8,976)	3,354	2,785	6,139	
FEBRUARY 28, 2008		404,159	22,989	12,538	210	(125,497)	(8,979)	(9,038)	2,593	2,378	4,971	
MARCH 31, 2008		405,560	23,233	12,538	210	(126,225)	(8,982)	(9,100)	2,769	1,435	4,204	
APRIL 30, 2008		408,252	23,842	12,541	210	(126,971)	(9,047)	(9,162)	2,346	1,615	3,961	
MAY 31, 2008		409,282	23,373	12,546	210	(127,698)	(9,075)	(9,224)	2,049	1,796	3,845	
JUNE 30, 2008	@1/2	194,946	11,702	6,273	105	(64,233)	(4,590)	(4,644)	956	718	1,674	
TOTAL TWELVE MONTHS		\$4,799,276	\$270,416	\$150,193	\$2,520	(\$1,493,822)	(\$107,291)	(\$107,590)	\$32,206	\$19,400	\$51,606	
MONTHLY AVERAGE		\$399,940	\$22,535	\$12,516	\$210	(\$124,485)	(\$8,941)	(\$8,966)	\$2,684	\$1,617	\$4,300	

AVERAGE GAS RATE BASE
TWELVE MONTHS ENDED JUNE 30, 2008
(\$000s)

EXHIBIT G-2
SCHEDULE 1
PAGE 2 OF 2

ORANGE AND ROCKLAND UTILITIES, INC.

AVERAGE GAS RATE BASE
TWELVE MONTHS ENDED OCTOBER 31, 2010
(\$000s)

MONTH ENDED	UTILITY PLANT				UTILITY PLANT RESERVES				C.W.I.P.		
	GAS PLANT IN SERVICE	COMMON UTILITY PLANT			GAS PLANT IN SERVICE	COMMON UTILITY PLANT		GAS PLANT IN SERVICE	NOT TAKING INTEREST		TOTAL
		COMMON UTILITY PLANT	COMMON UTILITY PLANT	COMMON UTILITY PLANT		COMMON UTILITY PLANT	COMMON UTILITY PLANT		GAS	COMMON	GAS
OCTOBER 31, 2009 @50%	\$213,225	\$13,627	\$6,273	\$105	(\$71,499)	(\$5,301)	(\$5,123)		\$1,449	\$873	\$2,321
NOVEMBER 30, 2009	437,130	27,415	12,546	210	(143,948)	(10,707)	(10,303)		2,898	1,771	4,669
DECEMBER 31, 2009	440,072	27,660	12,546	210	(144,918)	(10,811)	(10,360)		2,898	1,797	4,695
JANUARY 31, 2010	441,413	27,725	12,546	210	(145,900)	(10,917)	(10,417)		2,898	1,823	4,721
FEBRUARY 28, 2010	442,909	27,678	12,546	210	(146,884)	(11,024)	(10,474)		2,898	1,849	4,747
MARCH 31, 2010	444,389	28,005	12,546	210	(147,872)	(11,131)	(10,532)		2,898	1,875	4,773
APRIL 30, 2010	446,161	28,220	12,546	210	(148,862)	(11,240)	(10,588)		2,898	1,901	4,799
MAY 31, 2010	448,143	28,450	12,546	210	(149,856)	(11,351)	(10,644)		2,898	1,927	4,825
JUNE 30, 2010	450,973	28,677	12,546	210	(150,854)	(11,464)	(10,700)		2,898	1,953	4,850
JULY 31, 2010	453,536	28,938	12,546	210	(151,859)	(11,577)	(10,756)		2,898	1,979	4,876
AUGUST 31, 2010	456,238	28,995	12,546	210	(152,870)	(11,692)	(10,812)		2,898	2,005	4,902
SEPTEMBER 30, 2010	461,458	29,354	12,546	210	(153,886)	(11,808)	(10,868)		2,898	2,031	4,928
OCTOBER 31, 2010 @1/2	237,330	14,713	6,273	105	(77,456)	(5,963)	(5,462)		1,449	1,028	2,477
TOTAL TWELVE MONTHS	\$5,372,976	\$339,459	\$150,552	\$2,520	(\$1,786,663)	(\$134,987)	(\$127,040)		\$34,771	\$22,812	\$57,582
MONTHLY AVERAGE	\$447,748	\$28,288	\$12,546	\$210	(\$148,889)	(\$11,249)	(\$10,587)		\$2,898	\$1,902	\$4,799

ORANGE AND ROCKLAND UTILITIES, INC.

AVERAGE GAS RATE BASE
TWELVE MONTHS ENDED OCTOBER 31, 2010
(\$000s)

MONTH ENDED	M.T.A. SURFAC	ALGONQUIN CAPACITY PAYMENT	NET CUSTOMER OUTREACH	RATE CASE COSTS	MO/MT AUDIT	DISM	RAD EX/END	ENVIRONMENT	M/CP	ACCUMULATED DEFERRED SIT	ACCUMULATED DEFERRED SIT - MTA	ACCUMULATED DEFERRED SIT - NON - DEDUCTIBLE	ACRS / ADP	CAPITALIZED OVERHEADS 25% REDUCTION	DEFERRED F.I.T. - COMPUTER SOFTWARE	DEFERRED F.I.T. - LEASED VEHICLES	DEFERRED PENSION LIABILITY- ALLOWED	CUST. ADV. FOR CONSTRUCTION	GAS PERFORMANCE INCENTIVES	ACCUM. DEFERRED I.T.C.	ACCUM. DEFERRED MTA - INVS INCOME TAX	STATE INCOME TAX BENEFIT PRE 2000
OCTOBER 31, 2009 @50%	120	\$0	\$0	\$0	\$0	(\$7)	(\$3)	\$1,032	2,136	(\$2,272)	(\$799)	\$1,083	(\$23,063)	(\$6,066)	(\$46)	(\$88)	(\$906)	(\$20)	(\$75)	(\$422)	\$365	\$8
NOVEMBER 30, 2009	239	0	0	0	0	(14)	(6)	2,209	2,298	(4,818)	(1,647)	2,232	(46,348)	(12,150)	(91)	(179)	(1,812)	(40)	(\$148)	(837)	730	15
DECEMBER 31, 2009	239	0	0	0	0	(14)	(5)	2,209	2,298	(4,818)	(1,647)	2,298	(46,571)	(12,169)	(91)	(182)	(1,812)	(40)	(\$148)	(830)	730	15
JANUARY 31, 2010	239	0	0	0	0	(13)	(5)	2,654	2,372	(4,971)	(1,753)	2,372	(46,840)	(12,187)	(91)	(180)	(1,812)	(40)	(\$147)	(823)	730	15
FEBRUARY 28, 2010	239	0	0	0	0	(13)	(5)	3,099	2,446	(5,124)	(1,809)	2,446	(47,108)	(12,205)	(91)	(178)	(1,812)	(40)	(\$146)	(815)	730	15
MARCH 31, 2010	239	0	0	0	0	(12)	(5)	3,545	2,520	(5,277)	(1,864)	2,520	(47,376)	(12,224)	(91)	(177)	(1,812)	(40)	(\$145)	(808)	730	15
APRIL 30, 2010	239	0	0	0	0	(12)	(5)	3,363	2,669	(5,429)	(1,920)	2,594	(47,644)	(12,242)	(91)	(176)	(1,812)	(40)	(\$144)	(800)	730	15
MAY 31, 2010	239	0	0	0	0	(13)	(5)	3,272	2,743	(5,582)	(1,976)	2,743	(47,912)	(12,261)	(91)	(175)	(1,812)	(40)	(\$143)	(793)	730	15
JUNE 30, 2010	239	0	0	0	0	(11)	(5)	3,147	2,817	(5,735)	(2,032)	2,817	(48,180)	(12,279)	(91)	(174)	(1,812)	(40)	(\$142)	(785)	730	15
JULY 31, 2010	239	0	0	0	0	(11)	(4)	3,022	2,891	(5,888)	(2,087)	2,891	(48,448)	(12,297)	(91)	(173)	(1,812)	(40)	(\$141)	(778)	730	15
AUGUST 31, 2010	239	0	0	0	0	(10)	(4)	2,897	2,965	(6,040)	(2,143)	2,965	(48,716)	(12,316)	(91)	(173)	(1,812)	(40)	(\$140)	(770)	730	15
SEPTEMBER 30, 2010	239	0	0	0	0	(10)	(4)	2,897	2,965	(6,040)	(2,143)	2,965	(48,984)	(12,334)	(91)	(173)	(1,812)	(40)	(\$139)	(763)	730	15
OCTOBER 31, 2010	120	0	0	0	0	(5)	(2)	1,408	1,519	(3,173)	(1,127)	1,519	(24,626)	(6,176)	(46)	(86)	(906)	(20)	(\$89)	(378)	365	8
TOTAL TWELVE MONTHS	2,870	-	-	-	-	(144)	(58)	35,241	31,149	(65,185)	(23,053)	31,149	(571,816)	(146,905)	(1,092)	(2,121)	(21,744)	(476)	(1,728)	(9,602)	8,754	184
MONTHLY AVERAGE	239	-	-	-	-	(12)	(5)	2,937	2,596	(5,432)	(1,921)	2,596	(47,651)	(12,242)	(91)	(177)	(1,812)	(40)	(144)	(800)	730	15

TAX FACTOR

65.000% 65.000% 65.000% 65.000% 65.000% 65.000% 65.000% 65.000% 65.000% 65.000% 65.000% 65.000% 65.000% 65.000% 65.000% 65.000% 65.000% 65.000% 100.000% 65.000% 0.000% 0.000% 0.000%

ORANGE AND ROCKLAND UTILITIES, INC.
GAS AND COMMON PLANT IN SERVICE
ESTIMATE OF MONTHLY BALANCES
(\$000s)

	<u>July-08</u>	<u>Aug-08</u>	<u>Sep-08</u>	<u>Oct-08</u>
<u>GAS PLANT IN SERVICE</u>				
BEGINNING BALANCE	389,892	391,647	395,410	398,979
ADDITIONS				
DISTRIBUTION	1,838	3,762	3,568	3,759
GENERAL	9	106	106	106
TOTAL ADDITIONS	1,846	3,868	3,673	3,865
RETIREMENTS				
DISTRIBUTION	81.1	90.5	90.5	90.5
GENERAL	10.4	14.1	14.1	14.1
TOTAL RETIREMENTS	91.5	104.6	104.6	104.6
ENDING BALANCE	391,647	395,410	398,979	402,739
<u>COMMON PLANT IN SERVICE</u>				
BEGINNING BALANCE - COMMON	80,013	79,895	80,876	81,888
BEGINNING BALANCE - CIMS	52,016	52,016	52,016	52,016
ADDITIONS				
CIMS + OTHER @ 100%	0	0	0	0
COMMON @ 100%	137	1290	1320	1330
TOTAL ADDITIONS	137.0	1,289.6	1,319.6	1,329.5
RETIREMENTS				
CIMS + OTHER @ 100%	0	0	0	0
COMMON @ 100%	255	308	308	308
Total Common	255.4	308.1	308.1	308.1
ENDING BALANCE - COMMON	79,895	80,876	81,888	82,909
ENDING BALANCE - CIMS	52,016	52,016	52,016	52,016

ORANGE AND ROCKLAND UTILITIES, INC.
GAS AND COMMON PLANT IN SERVICE
ESTIMATE OF MONTHLY BALANCES
(\$000s)

	<u>Nov-08</u>	<u>Dec-08</u>	<u>Jan-09</u>	<u>Feb-09</u>	<u>Mar-09</u>	<u>April-09</u>	<u>May-09</u>	<u>Jun-09</u>	<u>July-09</u>	<u>Aug-09</u>	<u>Sep-09</u>	<u>Oct-09</u>
<u>GAS PLANT IN SERVICE</u>												
BEGINNING BALANCE	402,739	406,169	409,668	410,374	411,220	412,062	413,187	414,488	416,413	418,269	420,266	423,644
ADDITIONS												
DISTRIBUTION	3,428	3,498	776	915	911	1,194	1,371	1,994	1,925	2,066	3,448	2,657
GENERAL	106	106	35	35	35	35	35	35	35	35	35	254
TOTAL ADDITIONS	3,534	3,603	811	951	946	1,230	1,406	2,030	1,960	2,102	3,483	2,911
RETIREMENTS												
DISTRIBUTION	90.5	90.5	90.5	90.5	90.5	90.5	90.5	90.5	90.5	90.5	90.5	90.5
GENERAL	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1
TOTAL RETIREMENTS	104.6	104.6	104.6	104.6	104.6	104.6	104.6	104.6	104.6	104.6	104.6	104.6
ENDING BALANCE	406,169	409,668	410,374	411,220	412,062	413,187	414,488	416,413	418,269	420,266	423,644	426,450
<u>COMMON PLANT IN SERVICE</u>												
BEGINNING BALANCE - COMMON	82,909	83,918	84,935	84,986	84,837	84,872	85,328	86,196	87,240	87,896	88,240	92,575
BEGINNING BALANCE - CIMS	52,016	52,016	52,016	52,016	52,016	52,016	52,016	52,016	52,016	52,016	52,016	52,016
ADDITIONS												
CIMS + OTHER @ 100%	0	0	0	0	0	0	0	0	0	0	0	0
COMMON @ 100%	1317	1325	358	160	343	765	1175	1352	964	652	4643	909
TOTAL ADDITIONS	1,317.4	1,325.2	358.5	159.5	342.7	764.7	1,175.4	1,352.4	964.4	652.2	4,642.9	908.6
RETIREMENTS												
CIMS + OTHER @ 100%	0	0	0	0	0	0	0	0	0	0	0	0
COMMON @ 100%	308	308	308	308	308	308	308	308	308	308	308	308
Total Common	308.1	308.1	308.1	308.1	308.1	308.1	308.1	308.1	308.1	308.1	308.1	308.1
ENDING BALANCE - COMMON	83,918	84,935	84,986	84,837	84,872	85,328	86,196	87,240	87,896	88,240	92,575	93,176
ENDING BALANCE - CIMS	52,016	52,016	52,016	52,016	52,016	52,016	52,016	52,016	52,016	52,016	52,016	52,016

ORANGE AND ROCKLAND UTILITIES, INC.
GAS AND COMMON PLANT IN SERVICE
ESTIMATE OF MONTHLY BALANCES
(\$000s)

	<u>Nov-09</u>	<u>Dec-09</u>	<u>Jan-10</u>	<u>Feb-10</u>	<u>Mar-10</u>	<u>Apr-10</u>	<u>May-10</u>	<u>Jun-10</u>	<u>Jul-10</u>	<u>Aug-10</u>	<u>Sep-10</u>	<u>Oct-10</u>
<u>GAS PLANT IN SERVICE</u>												
BEGINNING BALANCE	426,450	437,130	440,072	441,413	442,909	444,389	446,161	448,143	450,973	453,536	456,238	461,458
ADDITIONS												
DISTRIBUTION	10,749	2,447	1,409	1,565	1,549	1,841	2,050	2,688	2,632	2,771	5,289	13,270
GENERAL	35	600	36	36	36	36	36	247	36	36	36	36
TOTAL ADDITIONS	10,785	3,046	1,445	1,601	1,585	1,877	2,086	2,935	2,668	2,807	5,325	13,306
RETIREMENTS												
DISTRIBUTION	90.5	90.5	90.5	90.5	90.5	90.5	90.5	90.5	90.5	90.5	90.5	90.5
GENERAL	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1
TOTAL RETIREMENTS	104.6	104.6	104.6	104.6	104.6	104.6	104.6	104.6	104.6	104.6	104.6	104.6
ENDING BALANCE	437,130	440,072	441,413	442,909	444,389	446,161	448,143	450,973	453,536	456,238	461,458	474,660
<u>COMMON PLANT IN SERVICE</u>												
BEGINNING BALANCE - COMMON	93,176	93,726	94,564	94,785	94,626	95,745	96,477	97,266	98,041	98,934	99,129	100,356
BEGINNING BALANCE - CIMS	52,016	52,016	52,016	52,016	52,016	52,016	52,016	52,016	52,016	52,016	52,016	52,016
ADDITIONS												
CIMS + OTHER @ 100%	0	0	0	0	0	0	0	0	0	0	0	0
COMMON @ 100%	858	1,147	529	148	1427	1040	1098	1083	1201	503	1535	551
TOTAL ADDITIONS	858.3	1,146.6	529.2	148.4	1,427.0	1,040.1	1,097.5	1,082.9	1,201.0	503.4	1,534.9	551.3
RETIREMENTS												
CIMS + OTHER @ 100%	0	0	0	0	0	0	0	0	0	0	0	0
COMMON @ 100%	308	308	308	308	308	308	308	308	308	308	308	308
Total Common	308.1	308.1	308.1	308.1	308.1	308.1	308.1	308.1	308.1	308.1	308.1	308.1
ENDING BALANCE - COMMON	93,726	94,564	94,785	94,626	95,745	96,477	97,266	98,041	98,934	99,129	100,356	100,599
ENDING BALANCE - CIMS	52,016	52,016	52,016	52,016	52,016	52,016	52,016	52,016	52,016	52,016	52,016	52,016

ORANGE AND ROCKLAND UTILITIES, INC.
ACCUMULATED PROVISION FOR DEPRECIATION
GAS AND COMMON PLANT IN SERVICE
ESTIMATE OF MONTHLY BALANCES
(\$000s)

	<u>July-08</u>	<u>Aug-08</u>	<u>Sep-08</u>	<u>Oct-08</u>
<u>GAS PLANT IN SERVICE</u>				
BEGINNING BALANCE	128,466	129,272	130,151	131,037
DISTRIBUTION				
GENERAL	749.6	779.7	787.0	794.0
UNALLOCATED	102.3	144.2	144.6	144.9
	(45.6)	(45.6)	(45.6)	(45.6)
NET ADDITIONS AND RETIREMENTS	806	878	886	893
ENDING BALANCE	129,272	130,151	131,037	131,930
<u>COMMON PLANT IN SERVICE</u>				
BEGINNING BALANCE - COMMON	31,383	31,665	31,942	32,224
BEGINNING BALANCE - CIMS	38,502	38,760	39,019	39,277
CIMS + OTHER @ 100%	258.4	258.4	258.4	258.4
COMMON @ 100%	282.5	276.9	281.7	286.9
NET ADDITIONS AND RETIREMENTS	540.9	535.3	540.1	545.3
ENDING BALANCE - COMMON	31,665	31,942	32,224	32,511
ENDING BALANCE - CIMS	38,760	39,019	39,277	39,536

EXHIBIT G-2

SCHEDULE

PAGE 1 OF 1

ORANGE AND ROCKLAND UTILITIES, INC.
ACCUMULATED PROVISION FOR DEPRECIATION
GAS AND COMMON PLANT IN SERVICE
ESTIMATE OF MONTHLY BALANCES
(\$000s)

	<u>Nov-08</u>	<u>Dec-08</u>	<u>Jan-09</u>	<u>Feb-09</u>	<u>Mar-09</u>	<u>Apr-09</u>	<u>May-09</u>	<u>Jun-09</u>	<u>Jul-09</u>	<u>Aug-09</u>	<u>Sep-09</u>	<u>Oct-09</u>
<u>GAS PLANT IN SERVICE</u>												
BEGINNING BALANCE	131,930	132,831	133,739	134,654	135,570	136,489	137,409	138,331	139,256	140,185	141,118	142,054
DISTRIBUTION												
GENERAL	801.2	807.9	814.7	816.0	817.7	819.3	821.5	824.0	827.8	831.5	835.4	842.1
UNALLOCATED	145.3	145.7	146.0	146.1	146.2	146.4	146.5	146.6	146.7	146.8	146.9	147.1
	(45.6)	(45.6)	(45.6)	(45.6)	(45.6)	(45.6)	(45.6)	(45.6)	(45.6)	(45.6)	(45.6)	(45.6)
NET ADDITIONS AND RETIREMENTS	901	908	915	917	918	920	922	925	929	933	937	944
ENDING BALANCE	132,831	133,739	134,654	135,570	136,489	137,409	138,331	139,256	140,185	141,118	142,054	142,998
<u>COMMON PLANT IN SERVICE</u>												
BEGINNING BALANCE - COMMON	32,511	32,803	33,100	33,403	33,706	34,009	34,312	34,618	34,930	35,248	35,569	35,893
BEGINNING BALANCE - CIMS	39,536	39,794	40,052	40,311	40,569	40,828	41,066	41,304	41,542	41,780	42,018	42,256
CIMS + OTHER @ 100%	258.4	258.4	258.4	258.4	258.4	258.4	258.0	238.0	238.0	238.0	238.0	238.0
COMMON @ 100%	292.1	297.3	302.5	303.3	302.4	302.9	306.6	311.2	318.4	321.1	323.8	353.1
NET ADDITIONS AND RETIREMENTS	550.5	555.7	560.9	561.7	560.8	540.9	544.6	549.2	556.4	559.1	561.8	591.1
ENDING BALANCE - COMMON	32,803	33,100	33,403	33,706	34,009	34,312	34,618	34,930	35,248	35,569	35,893	36,246
ENDING BALANCE - CIMS	39,794	40,052	40,311	40,569	40,828	41,066	41,304	41,542	41,780	42,018	42,256	42,494

ORANGE AND ROCKLAND UTILITIES, INC.
ACCUMULATED PROVISION FOR DEPRECIATION
GAS AND COMMON PLANT IN SERVICE
ESTIMATE OF MONTHLY BALANCES
(\$000s)

	<u>Nov-09</u>	<u>Dec-09</u>	<u>Jan-10</u>	<u>Feb-10</u>	<u>Mar-10</u>	<u>Apr-10</u>	<u>May-10</u>	<u>Jun-10</u>	<u>Jul-10</u>	<u>Aug-10</u>	<u>Sep-10</u>	<u>Oct-10</u>
<u>GAS PLANT IN SERVICE</u>												
BEGINNING BALANCE	142,998	143,948	144,918	145,900	146,884	147,872	148,862	149,856	150,854	151,859	152,870	153,886
DISTRIBUTION	847.2	868.4	873.1	875.7	878.6	881.5	885.0	888.9	894.1	899.1	904.4	914.8
GENERAL	148.0	148.1	154.1	154.2	154.3	154.4	154.6	154.7	156.9	157.0	157.1	157.3
UNALLOCATED	(45.6)	(45.6)	(45.6)	(45.6)	(45.6)	(45.6)	(45.6)	(45.6)	(45.6)	(45.6)	(45.6)	(45.6)
NET ADDITIONS AND RETIREMENTS	950	971	982	984	987	990	994	998	1,005	1,011	1,016	1,026
ENDING BALANCE	143,948	144,918	145,900	146,884	147,872	148,862	149,856	150,854	151,859	152,870	153,886	154,912
<u>COMMON PLANT IN SERVICE</u>												
BEGINNING BALANCE - COMMON	36,246	36,602	36,959	37,323	37,688	38,053	38,427	38,806	39,190	39,579	39,973	40,367
BEGINNING BALANCE - CIMS	42,494	42,732	42,970	43,208	43,446	43,684	43,917	44,151	44,384	44,618	44,852	45,085
CIMS + OTHER @ 100%	238.0	238.0	238.0	238.0	238.0	233.6	233.6	233.6	233.6	233.6	233.6	233.6
COMMON @ 100%	356.1	357.3	363.4	365.7	364.7	374.2	378.6	384.4	388.4	393.8	394.6	402.1
NET ADDITIONS AND RETIREMENTS	594.1	595.3	601.4	603.7	602.7	607.8	612.2	618.0	622.0	627.4	628.2	635.7
ENDING BALANCE - COMMON	36,602	36,959	37,323	37,688	38,053	38,427	38,806	39,190	39,579	39,973	40,367	40,769
ENDING BALANCE - CIMS	42,732	42,970	43,208	43,446	43,684	43,917	44,151	44,384	44,618	44,852	45,085	45,319

ORANGE & ROCKLAND UTILITIES, INC.
GAS WORKING CAPITAL - SUMMARY
(\$000s)

<u>DESCRIPTION</u>	<u>TWELVE MONTHS ENDED</u>			
	<u>JUNE 30, 2008</u> <u>PER BOOKS</u>	<u>ADJUSTMENTS</u>	<u>JUNE 30, 2008</u> <u>AS ADJUSTED</u>	<u>OCT. 31,</u> <u>2010</u>
OPERATION & MAINTENANCE EXP.	\$ 5,804	\$ (56)	\$ 5,748	\$ 6,465
MATERIALS & SUPPLIES	1,353	-	1,353	1,425
PREPAYMENTS	3,185	-	3,185	4,653
WORKING CAPITAL REQUIREMENTS	<u>\$ 10,342</u>	<u>\$ (56)</u>	<u>\$ 10,286</u>	<u>\$ 12,543</u>

ORANGE & ROCKLAND UTILITIES, INC.
CASH WORKING CAPITAL - GAS
TWELVE MONTHS ENDED JUNE 30, 2008 AND OCTOBER 31, 2010
(\$000s)

<u>DESCRIPTION</u>	<u>TWELVE MONTHS ENDED</u>			
	<u>JUNE 30, 2008</u> <u>PER BOOKS</u>	<u>NORMALIZING</u> <u>ADJUSTMENTS (A)</u>	<u>JUNE 30, 2008</u> <u>AS ADJUSTED</u>	<u>OCT. 31,</u> <u>2010</u>
OPERATION & MAINTENANCE EXP.	\$ 209,710	\$ (2,931)	\$ 206,779	\$ 200,655
LESS:				
PURCHASED GAS	146,010	-	146,010	138,403
UNCOLLECTIBLES	1,271	(26)	1,245	1,185
REGULATORY ITEMS				
DEFERRED PURCHASED GAS EXP.	10,989	(1,503)	9,486	5,761
RESEARCH & DEVELOPMENT	(10)	10	-	-
PENSION AMORTIZATION	1,970	(505)	1,465	1,084
OPEB AMORTIZATION	1,359	(494)	865	530
GAS LOW INCOME PROGRAM	34	(34)	-	-
OUTREACH & EDUCATION	-	-	-	(150)
RATE CASE COSTS	17	-	17	18
GAS MAINS AMORITIZATION	150	-	150	300
MGP	1,558	-	1,558	1,803
CONSERVATION & DSM	(68)	68	-	-
WORKING CAPITAL REQUIREMENTS	<u>\$ 46,430</u>	<u>\$ (447)</u>	<u>\$ 45,983</u>	<u>\$ 51,721</u>
CASH WORKING CAPITAL @ 1/8	<u>\$ 5,804</u>	<u>\$ (56)</u>	<u>\$ 5,748</u>	<u>\$ 6,465</u>

(A) See Exhibit G-5, Summary, Page 3 of 3

ORANGE & ROCKLAND UTILITIES, INC.
GAS WORKING CAPITAL
MATERIALS AND SUPPLIES
TWELVE MONTHS ENDED JUNE 30, 2008 AND OCTOBER 31, 2010
(\$000s)

MONTH	MATERIALS & STORES GENERAL EXPENSE	MATERIALS & STORES COMMON- GAS PORTION *	JUNE 30, 2008 TOTAL	NORMALIZING ADJUSTMENTS	JUNE 30, 2008 AS ADJUSTED	ESCALATION	OCTOBER 31, 2010 TOTAL
JUNE 30, 2007 @50%	\$518	\$147	\$665	\$0	\$665	\$35	\$700
JULY 31, 2007	\$1,083	\$279	1,362	-	1,362	72	1,435
AUGUST 31, 2007	\$1,060	\$297	1,357	-	1,357	72	1,428
SEPTEMBER 30, 2007	\$1,020	\$286	1,306	-	1,306	69	1,375
OCTOBER 31, 2007	\$998	\$303	1,301	-	1,301	69	1,370
NOVEMBER 30, 2007	\$973	\$292	1,264	-	1,264	67	1,331
DECEMBER 31, 2007	\$960	\$290	1,250	-	1,250	66	1,316
JANUARY 31, 2008	\$1,020	\$320	1,340	-	1,340	71	1,411
FEBRUARY 28, 2008	\$1,023	\$322	1,345	-	1,345	71	1,416
MARCH 31, 2008	\$1,118	\$296	1,414	-	1,414	75	1,489
APRIL 30, 2008	\$1,100	\$294	1,394	-	1,394	74	1,468
MAY 31, 2008	\$1,183	\$298	1,481	-	1,481	78	1,560
JUNE 30, 2008 @50%	\$612	\$144	756	-	756	40	796
TWELVE MONTH TOTAL	\$12,667	\$3,568	\$16,234	\$0	\$16,234	\$860	\$17,094
TWELVE MONTH AVERAGE	\$1,056	\$297	\$1,353	\$0	\$1,353	\$72	\$1,425

* COMMON MATERIALS & SUPPLIES ALLOCATED TO GAS @ 29.25%

ORANGE & ROCKLAND UTILITIES, INC.
GAS WORKING CAPITAL
PREPAYMENTS
(\$000s)

<u>DESCRIPTION</u>	<u>AVERAGE BALANCE FOR TWELVE MONTHS ENDED</u>	
	<u>JUNE 30, 2008 PER BOOKS</u>	<u>OCT. 31, 2010</u>
LOCAL PROPERTY TAXES	\$ 3,131	\$ 4,596
INSURANCE	27	28
NYPSC ASSESSMENT	218	230
NYS GROSS RECEIPTS	(1)	(1)
NYS 1% UTILITY TAX	(119)	(125)
NYS 2% AND 2.45% UTILITY TAX	(78)	(82)
INTEREST ON UNFUNDED DEBT	7	7
TOTAL AVERAGE PREPAYMENTS	<u>\$ 3,185</u>	<u>\$ 4,653</u>
ESCALATION FACTOR UTILIZED: FOR 12 MONTHS ENDED 10/31/10	5.3%	

ORANGE & ROCKLAND UTILITIES, INC.
EARNINGS BASE / CAPITALIZATION ADJUSTMENT
TWELVE MONTHS ENDED JUNE 30, 2008
(\$000s)

<u>CAPITALIZATION</u>	<u>TOTAL</u>			
LONG-TERM DEBT	\$	379,661		
COMMON STOCK		240,637		
RETAINED EARNINGS		<u>213,576</u>		
SUB-TOTAL	\$	833,874		
SHORT-TERM DEBT		<u>41,474</u>		
SUB-TOTAL	\$	875,348		
<u>ADDITIONS</u>				
CUSTOMER DEPOSITS	\$	12,357		
INTEREST ON CUSTOMER DEPOSITS		928		
CUSTOMER ADVANCES		1,377		
INTEREST ON REFUNDS - UNDERGROUND CUSTOMER ADVANCES		51		
DIVIDENDS DECLARED		5,200		
ADDITION TO RETAINED EARNINGS-SFAS 90		-		
OTHER WORK IN PROGRESS / CLEARING ACCOUNTS		(481)		
FUEL SUPPLIER REFUNDS		842		
FUEL SAVINGS FOR GAS USED IN POWER GENERATION		49		
INTERRUPTIBLE BENEFITS		(919)		
GAS STRANDED COST SURCHARGE RECOVERY		-		
PEAK SHAVING GAS COST RECOVERIES		160		
PIPELINE REFUNDS		54		
INTEREST ON PIPELINE REFUNDS		-		
COMPETITIVE ENHANCEMENT FUND		(33)		
PENSION OBLIGATION (EXCL. PORTION IN RATE BASE)		6,652		
OPEB OBLIGATION		16,017		
INTEREST ON PENSION / OPEB OBLIGATIONS		1,520		
PROPERTY TAX REFUNDS & INTEREST		793		
STORM DAMAGE RESERVE & INTEREST		<u>245</u>		
TOTAL ADDITIONS	\$	44,812		
<u>DEDUCTIONS</u>				
INVESTMENT IN SUBSIDIARIES	\$	170,961		
NET RECEIVABLE / PAYABLE - ASSOCIATED COMPANIES		(19,894)		
TEMPORARY CASH INVESTMENTS		5,519		
CONSTRUCTION COSTS SUBJECT TO AFUDC		18,507		
GAS STORED UNDERGROUND		39,953		
GAS STORAGE CARRYING CHARGES		855		
NYS INCOME TAX - OVERCOLLECTION PORTION (2000/2001)		(4)		
NET G.A.C. UNDER COLLECTIONS & INTEREST		<u>1,187</u>		
TOTAL DEDUCTIONS	\$	<u>217,084</u>		
TOTAL CAPITALIZATION		703,076		
AVERAGE RATE BASE AS ADJUSTED		735,757	<u>ELECTRIC</u> 483,478	<u>GAS</u> 252,279
ALLOCATION RATIO *		105.83%	62.72%	37.28%
RATE BASE (OVER) / UNDER CAPITALIZATION	\$	<u>(32,681)</u>	\$ (20,497)	\$ (12,183)
				<u>OTHER ELECTRIC</u> (1,905)

* ELECTRIC DISCOUNTED FOR SUBSIDIARIES BY 8.87%

ORANGE AND ROCKLAND UTILITIES, INC.
Forecasted Firm Gas Delivery Volumes for the Twelve Months Ending October 31, 2010
(MCF)

Line No.	Description	(Column 1)		(Column 2)		(Column 3)		(Column 4)		(Column 5) Firm Delivery Volumes
		SC1/6	Residential Domestic	SC1/6	Residential Heating	SC1/6	Commercial & Industrial	SC2/6	Commercial & Industrial	
1	Billed Delivery Volumes:									
1	12 Months Ended September 30, 2008	142,760		13,184,830		2,241,110		3,704,000		19,272,700
2	Weather Normalization Adjustment	-		246,640		39,240		57,510		343,390
3	Net New Business Adjustment	-		190,500		10,800		177,600		378,900
4	Billing Cycle Adjustment	800		(40,200)		(6,600)		(10,300)		(56,300)
5	Economy Adjustment	-		-		39,200		-		39,200
6	Price Elasticity Adjustment	-		(151,000)		(116,900)		-		(267,900)
	Forecasted Firm Billed Delivery Volumes:									
7	12 Months Ending October 31, 2010	143,560		13,430,770		2,206,850		3,928,810		19,709,990
8	Unbilled Delivery Volumes									168,630
	Forecasted Firm Delivery Volumes:									
9	12 Months Ending October 31, 2010									19,878,620

ORANGE AND ROCKLAND UTILITIES, INC.
Forecasted Firm Gas Delivery Volumes for the Twelve Months Ending October 31, 2009
(MCF)

Line No.	Description	(Column 1) SC1/6	(Column 2) Residential Heating	(Column 3) SC1/6	(Column 4) SC2/6	(Column 5) Firm Delivery Volumes
		Residential Domestic	Commercial & Industrial	Commercial & Industrial	Commercial & Industrial	Total
1	Billed Delivery Volumes:					
1	12 Months Ended September 30, 2008	142,760	13,184,830	2,241,110	3,704,000	19,272,700
2	Weather Normalization Adjustment	-	246,640	39,240	57,510	343,390
3	Net New Business Adjustment		107,800	7,000	134,900	249,700
4	Billing Cycle Adjustment	(2,000)	(145,000)	(24,800)	(42,100)	(213,900)
5	Economy Adjustment			10,100		10,100
6	Price Elasticity Adjustment		(147,700)	(116,100)		(263,800)
	Forecasted Firm Billed Delivery Volumes:					
7	12 Months Ending October 31, 2009	140,760	13,246,570	2,156,550	3,854,310	19,398,190
8	Unbilled Delivery Volumes					148,580
9	Forecasted Firm Delivery Volumes:					
	12 Months Ending October 31, 2009					19,546,770

ORANGE AND ROCKLAND UTILITIES, INC.
Forecasted Firm Gas Delivery Volumes for the Twelve Months Ending October 31, 2011 and October 31, 2012
(MCF)

Line No.	Description	(Column 1) SC1/6 Residential Domestic	(Column 2) SC1/6 Residential Heating	(Column 3) SC1/6 Commercial & Industrial	(Column 4) SC2/6 Commercial & Industrial	(Column 5) Firm Delivery Volumes Total
1	Forecasted Firm Billed Delivery Volumes:					
2	12 Months Ending October 31, 2010	143,560	13,430,770	2,206,850	3,928,810	19,709,990
3	New Business Adjustment		107,300	7,000	38,300	152,600
4	Billing Cycle Adjustment	(2,100)	(40,600)	(6,800)	(12,600)	(62,100)
5	Economy Adjustment			27,300		27,300
6	Price Elasticity Adjustment		(92,400)	(21,600)		(114,000)
7	Forecasted Firm Billed Delivery Volumes:					
8	12 Months Ending October 31, 2011	141,460	13,405,070	2,212,750	3,954,510	19,713,790
9	Unbilled Delivery Volumes					156,130
10	Forecasted Firm Delivery Volumes:					
11	12 Months Ending October 31, 2011					19,869,920
12	Forecasted Firm Billed Delivery Volumes:					
13	12 Months Ending October 31, 2011	141,460	13,405,070	2,212,750	3,954,510	19,713,790
14	New Business Adjustment		18,800	67,400	115,900	202,100
15	Billing Cycle Adjustment	1,800	69,200	11,200	18,200	100,400
16	Economy Adjustment			18,700		18,700
17	Price Elasticity Adjustment			(29,600)	(130,900)	(160,500)
18	Forecasted Firm Billed Delivery Volumes:					
19	12 Months Ending October 31, 2012	143,260	13,493,070	2,280,450	3,957,710	19,874,490
20	Unbilled Delivery Volumes					211,530
21	Forecasted Firm Billed Delivery Volumes:					
22	12 Months Ending October 31, 2012					20,086,020

ORANGE AND ROCKLAND UTILITIES, INC.
Forecasted Gas Delivery Revenues for the Twelve Months Ending October 31, 2010

Line No.	Service Classification	Delivery Revenues				Monthly Gas Adjustments	Gas Supply Charge	Increase in Rates and Charges	Total Revenue	Proposed Base Rate Increase	Total Revenue at Proposed Rates
		Gas Delivery Volumes (MCF)	Non-Competitive	Competitive **							
		(Column 1)	(Column 2)	(Column 3)	(Column 4)	(Column 5)	(Column 6)	(Column 7)	(Column 8)	(Column 9)	
1	SC1/6 Residential & Domestic	13,574,330	63,197	4,114	167	109,122	2,094	178,694			
2	SC1/6 Commercial & Industrial	2,206,850	8,500	368	27	10,193	89	19,177			
3	SC2/6 Commercial & Industrial	2,498,510	8,514	297	31	16,172	118	25,132			
4	SC6 Large C&I Transportation	1,430,300	4,114	27	18	65	20	4,244			
5	Total Firm Delivery - Billed	19,709,990	84,325	4,806	243	135,552	2,321	227,247			
6	Total Firm Delivery - Unbilled	168,630	754	-	-	-	-	754			
7	Total Firm Delivery	19,878,620	85,079	4,806	243	135,552	2,321	228,001			
8	SC5*	1,900	7	-	-	21	-	28			
9	SC8 / 13 ***	2,842,500	2,217	-	-	-	12	2,229			
10	SC10 ****	2,477,800	372	-	-	7,204	34	7,610			
11	Total Interruptible	5,322,200	2,596	-	-	7,225	46	9,867			
12	Total	25,200,820	87,675	4,806	243	142,777	2,367	237,868			

* Includes Billed and Unbilled

** Competitive Charges include Billing and Payment Processing Charges and Merchant Function Charges

*** SC 3 is included in SC8 /13

**** SC10 customer is assumed to transfer from full service to transportation only service starting February 1, 2010.

The 7,204 represents gas supply charge for the months of November 2009 through January 2010 only.

ORANGE AND ROCKLAND UTILITIES, INC.
GAS FIRM DELIVERY VOLUMES AND DELIVERY REVENUES
(Billed and UnBilled)

	Rate Year Ending	Delivery Volumes (MCFs)	Delivery Revenues (@ 10/2008 Rates) (\$000)
1	October 31, 2010	19,878,620	\$ 85,079
2	October 31, 2011	19,869,920	\$ 85,369
3	October 31, 2012	20,086,020	\$ 86,731

ORANGE AND ROCKLAND UTILITIES, INC.
GAS INTERRUPTIBLE DELIVERY VOLUMES AND DELIVERY REVENUES

		Rate Year Twelve Months Ending		
		<u>October 31, 2010</u>	<u>October 31, 2011</u>	<u>October 31, 2012</u>
	<u>Delivery Volumes (MCF)</u>			
1	SC 5	1,900	1,900	1,900
2	SC 8/13	2,842,500	2,842,500	2,852,500
3	<u>SC 10</u>	<u>2,477,800</u>	<u>2,477,800</u>	<u>2,486,100</u>
4	Total	5,322,200	5,322,200	5,340,500
	<u>Delivery Revenues - \$000</u>			
5	SC 5	\$7	\$7	\$7
6	SC 8/13	\$2,217	\$2,217	\$2,225
7	<u>SC 10</u>	<u>\$372</u>	<u>\$372</u>	<u>\$373</u>
8	Total	\$2,596	\$2,596	\$2,605

Exhibit G-3

Schedule 6

ORANGE AND ROCKLAND UTILITIES, INC.

INDEX OF SCHEDULES

Gas Operating Income for the Twelve Months
Ended June 30, 2008 and October 31, 2010

<u>SCHEDULE</u>	<u>TITLE OF SCHEDULE</u>	<u>WITNESS</u>
1	Gas Operating Income	Accounting Panel
2	Gas Income Statement	"
3	Operating Revenues - Gas	"
4	Depreciation Calculation - Gas	"
5	Taxes Other than Income Taxes - Gas	"
6	State Income Tax Expense - Gas	"
7	Federal Income Tax Expense - Gas	"
8	Interest Expense Calculation	"
9	Summary of Adjustments to Gas Cost of Service	See Schedule 5
10	Fund Requirements and Sources for the Twelve Months Ending October 31, 2010	Accounting Panel

ORANGE AND ROCKLAND UTILITIES, INC.

Gas Operating Income

For The Twelve Months Ended June 30, 2008 and October 31, 2010

(\$000s)

	Normalized Test Year The Twelve Months Ended June 30, 2008	Adjustments To Reflect Conditions In The Rate Year	Rate Year The Twelve Months Ended October 31, 2010
<u>Operating Revenues</u>			
Sales to Public	\$249,605	(\$12,769)	\$236,836
Sales for Resale	1,533	515	2,048
Delivery Revenues	251,138	(12,254)	238,884
Other Operating Revenues	3,158	(8)	3,150
Total Operating Revenues	254,296	(12,262)	242,034
<u>Operating Expenses</u>			
Production & Purchases	156,279	(11,084)	145,196
Transmission	-	-	-
Distribution	17,979	2,766	20,745
Customer Accounts	6,186	400	6,586
Customer Service	1,826	199	2,025
Sales Promotion	9	0	9
Admin. & General	24,498	1,596	26,094
Subtotal Operating Expenses	206,777	(6,122)	200,655
Depreciation and Amortization	9,401	1,752	11,153
Taxes Other Than Income Taxes	11,793	1,501	13,294
Total Gas Operating Revenue Deductions	227,971	(2,869)	225,102
Gas Operating Income Before Income Taxes	26,325	(9,392)	16,932
<u>Income Taxes</u>			
State Income Taxes	973	(637)	336
Federal Income Tax	4,896	(6,614)	(1,718)
Deferred Federal Income Taxes	(971)	4,097	3,126
Total Income Taxes	4,898	(3,154)	1,744
Gas Operating Income	\$21,427	(\$6,238)	\$15,188

GAS INCOME STATEMENT

TWELVE MONTHS ENDED JUNE 30, 2008 AND OCTOBER 31, 2010
(\$000s)

EXHIBIT G-4
SCHEDULE 2
PAGE 1 of 2

ORANGE AND ROCKLAND UTILITIES, INC.
COMPUTATION OF REVENUE REQUIREMENT - GAS
TWELVE MONTHS ENDED OCTOBER 31, 2010
(\$000s)

	Amount
RATE BASE (Exhibit G-2, Summary)	\$ 273,943
EARNINGS BASE/CAPITALIZATION ADJUSTMENT (Exhibit G-4, Schedule 8)	(12,183)
INDICATED RATE BASE	\$ 261,760
RATE OF RETURN (Exhibit G-8, Schedule 1)	9.48%
TOTAL RETURN REQUIRED	\$ 24,813
EARNED RETURN (Exhibit G-4, Schedule 2, Page 1)	14,183
ADDITIONAL RETURN REQUIRED	\$ 10,630
DIVIDED BY RETENTION FACTOR *	59.81%
ADDITIONAL REVENUE REQUIREMENT	\$ 17,773

* CALCULATION OF RETENTION FACTOR:

	%	Amount
ADDITIONAL REVENUE	100.00%	\$ 17,773
LESS: REVENUE TAXES	1.03%	183
: LATE PAYMENT CHARGE REVENUES	-0.55%	(98)
: UNCOLLECTIBLES	0.47%	84
SUBTOTAL	99.05%	17,604
LESS: SIT ON ABOVE @ 7.1%	7.03%	1,249
: FIT ON ABOVE @ 35%	32.21%	5,725
	59.81%	\$ 10,630

ORANGE AND ROCKLAND UTILITIES, INC.
Forecasted Gas Delivery Revenues for the Twelve Months Ending October 31, 2010

Line No.	Service Classification	Gas Delivery Volumes (Column 1)	Delivery Revenue (\$000) (Column 2)	Non-Competitive (\$000) (Column 3)	Competitive ** (Column 5)	Gas Supply Charge (\$000) (Column 6)	Increase in rates and charges (\$000) (Column 7)	Total Revenue Before Rate Increase (\$000) (Column 8)	Proposed Base Rate Increase (\$000) (Column 9)	Total Revenue at Proposed Rate (\$000) (Column 10)
1	SC1/6 Residential & Domestic	13,574,330	63,197	4,281	607	108,514	2,094	178,693		178,693
2	SC1/6 Commercial & Industrial	2,206,850	8,500	395	96	10,094	89	19,174		19,174
3	SC2/6 Commercial & Industrial	2,498,510	8,514	328	118	16,058	118	25,136		25,136
4	SC6 Large C&I Transportation	1,430,300	4,114	45	65		20	4,244		4,244
5	Total Firm Delivery - Billed	19,709,990	84,325	5,049	886	134,666	2,321	227,247	17,773	245,020
6	Total Firm Delivery - Unbilled	168,630	754	-	-	-	-	754		754
7	Total Firm Delivery	19,878,620	85,079	5,049	886	134,666	2,321	228,001	17,773	245,774
8	SC5*	1,900	7		17		-	24		24
9	SC8 / 13***	2,842,500	2,217		-		17	2,234		2,234
10	SC10****	2,477,800	372			6,176	30	6,578		6,578
11	Total Interruptible	5,322,200	2,596	-	-	6,193	47	8,836	-	8,836
12	Total	25,200,820	87,675	5,049	886	140,859	2,368	236,836	17,773	254,610

Forecast Revenues -- I/S

* Includes Billed and Unbilled

** Competitive Charges include Billing and Payment Processing Charges and Merchant Function Charges

*** SC 3 is included in SC8 /13

**** SC10 customer is assumed to transfer from full service to transportation only service starting February 1, 2010.

The \$6,176,000 represents gas cost for the months of November 2008 through January 2010 only.

ORANGE AND ROCKLAND UTILITIES, INC.
OTHER OPERATING REVENUES - GAS
FOR THE TWELVE MONTHS ENDED JUNE 30, 2008 &
OCTOBER 31, 2010
(\$'000s)

	TWELVE MONTHS ENDED 6/30/08 PER BOOKS	TWELVE MONTHS ENDED 6/30/08 AS ADJUSTED	NORMALIZING AMOUNT	REF.	AMOUNT	RATE CASE REF.	RATE YEAR AS ADJUSTED	PROPOSED RATE INCREASE	RATE YEAR AS ADJUSTED FOR PROPOSED RATE INCREASE
MISCELLANEOUS SERVICE REVENUES									
Late Payment Charge Revenues	\$ 1,361	\$ 1,361	\$ -	1	(586)		\$ 1,291	\$ 98	\$ 1,389
Billing And Payment Processing (Retail Access)	586	-	(508)	2	-		-	-	-
Rate Relief Phase In: Case 05-G-1494	508	-	(508)		-		-	-	-
POR Discount	417	417	-		(21)		396	-	396
Market Billing Services	189	189	-		-		189	-	189
Gas Service Revenues (reconnects, accommodation)	26	133	-		-		159	-	159
Sale of M&S Stock	16	12	-		-		28	-	28
Bad Check Charges	4	(1)	-		-		3	-	3
Amortization of NYS Tax Rate Change	(39)	39	-		-		-	-	-
Gas Hedging Program - Interest	(27)	27	-		-		-	-	-
Total Other Operating Revenues	3,042	2,157	(885)		(91)		2,066	98	2,164
Non Firm Revenue Imputation									
Power Generation Transportation	1,370	650	(720)		-		650	-	650
MFC / GSC / MGA -- UNBUNDLED REVENUES									
Winter Bundled Sales	443	-	(443)		-		-	-	-
Merchant Function Charge (True-Up)	1	(1)	-		-		-	-	-
Gas R&D Recovery Deferral	(1,009)	-	1,009		-		-	-	-
Gas Peak Shaving	(2)	-	2		-		-	-	-
Total True-Up Revenues	(367)	-	567		-		-	-	-
JOINT USE BENEFITS									
Intercompany Billing	368	351	(17)		-		351	-	351
REVENUE SUBJECT TO REFUND									
2007 Penalties For Customer Service Surveys	(100)	-	100		-		-	-	-
Passback 2006 Penalties For Customer Service Survey	-	-	-		50		50	-	50
Passback 2007 Penalties For Customer Service Survey	-	-	-		33		33	-	33
Passback Gas Performance Incentive 05-G-1494	20	(20)	-		-		-	-	-
Passback SIT Transitional Benefits 05-G-1494	678	(678)	-		-		-	-	-
Passback SIT Benefit Rate Differential	55	(55)	-		-		-	-	-
2007 Penalties For Line Losses	(1,030)	-	1,030		-		-	-	-
Total Revenue Subject To Refund	(377)	-	377		83		83	-	83
TOTAL OTHER OPERATING REVENUES	\$ 3,836	\$ 3,158	\$ (678)		\$ (8)		\$ 3,150	\$ 98	\$ 3,248

Orange and Rockland Utilities, Inc.
Gas Rate Case
Plant Depreciation Expense-Current Rates
July 2008 to October 2009

Exhibits G-4
Schedule 4
Page 1 of 3

	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09
Gas Plant In Service Beginning Balance:																
Unallocated																
Mfg Gas Production Plant	30,586.5	30,583.5	30,580.4	30,577.3	30,574.2	30,571.1	30,568.0	30,564.9	30,561.8	30,558.7	30,555.6	30,552.5	30,549.4	30,546.3	30,543.2	30,540.1
Distribution	366,770.8	367,530.6	371,205.4	374,880.5	378,555.3	381,986.3	385,108.7	388,597.2	392,025.1	395,448.2	398,855.1	402,248.7	405,627.7	408,993.0	412,348.7	415,695.0
Distribution Future	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3
Information System	601.0	601.0	601.0	601.0	601.0	601.0	601.0	601.0	601.0	601.0	601.0	601.0	601.0	601.0	601.0	601.0
Intangible Plant	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2
Office Buildings	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9
Office Furniture	164.0	152.2	150.0	147.8	145.6	143.4	141.2	139.0	136.8	134.6	132.4	130.2	128.0	125.8	123.6	121.4
Automobiles	169.9	169.9	169.9	169.9	169.9	169.9	169.9	169.9	169.9	169.9	169.9	169.9	169.9	169.9	169.9	169.9
Light Trucks	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8
Heavy Trucks	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7
General Equipment	858.6	867.1	885.2	905.3	924.4	943.5	962.6	981.7	1,000.8	1,019.9	1,039.0	1,058.1	1,077.2	1,096.3	1,115.4	1,134.5
Data Handling Equipment	3,977.2	3,968.9	4,043.7	4,118.5	4,193.3	4,268.1	4,342.9	4,417.7	4,492.5	4,567.3	4,642.1	4,716.9	4,791.7	4,866.5	4,941.3	5,016.1
Easements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Trailers	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	411,240.2	412,995.1	415,758.5	420,327.2	424,067.5	427,517.2	431,016.0	434,722.6	438,568.9	442,408.8	446,334.8	450,256.5	454,171.6	458,081.0	461,985.9	465,891.1

Gas Plant Additions:																
Unallocated																
Mfg Gas Production Plant	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Distribution	1,837.6	3,782.2	3,597.6	3,759.1	3,428.4	3,497.8	775.9	915.3	910.5	1,194.3	1,371.1	1,994.4	1,924.7	2,066.2	3,447.5	2,056.7
Distribution Future	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Information System	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Intangible Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Office Buildings	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Office Furniture	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Automobiles	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Light Trucks	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Heavy Trucks	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
General Equipment	8.5	19.1	19.1	19.1	19.1	19.1	35.3	35.3	35.3	35.3	35.3	35.3	35.3	35.3	35.3	35.3
Data Handling Equipment	0.3	89.7	86.7	86.7	86.7	86.5	0	0	0	0	0	0	0	0	0	218.88065
Easements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Trailers	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	1,846.4	3,888.0	3,673.3	3,864.9	3,534.2	3,603.4	811.2	950.6	946.8	1,229.6	1,406.3	2,029.7	1,960.0	2,101.6	3,482.8	2,910.8

Gas Plant Retirements:																
Unallocated																
Mfg Gas Production Plant	3.3	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
Distribution	77.8	87.4	87.4	87.4	87.4	87.4	87.4	87.4	87.4	87.4	87.4	87.4	87.4	87.4	87.4	87.4
Distribution Future	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Information System	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Intangible Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Office Buildings	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Office Furniture	1.8	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Automobiles	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Light Trucks	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Heavy Trucks	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
General Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Data Handling Equipment	8.6	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9
Easements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Trailers	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	91.5	104.6	104.6	104.6	104.6	104.6	104.6	104.6	104.6	104.6	104.6	104.6	104.6	104.6	104.6	104.6

Gas Plant Ending Balance:																
Unallocated																
Mfg Gas Production Plant	30,583.5	30,580.4	30,577.3	30,574.2	30,571.1	30,568.0	30,564.9	30,561.8	30,558.7	30,555.6	30,552.5	30,549.4	30,546.3	30,543.2	30,540.1	30,537.0
Distribution	367,530.6	371,205.4	374,880.5	378,555.3	381,986.3	385,108.7	388,597.2	392,025.1	395,448.2	398,855.1	402,248.7	405,627.7	408,993.0	412,348.7	415,695.0	419,051.2
Distribution Future	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3
Information System	601.0	601.0	601.0	601.0	601.0	601.0	601.0	601.0	601.0	601.0	601.0	601.0	601.0	601.0	601.0	601.0
Intangible Plant	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2
Office Buildings	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9
Office Furniture	162.2	150.0	147.8	145.6	143.4	141.2	139.0	136.8	134.6	132.4	130.2	128.0	125.8	123.6	121.4	119.2
Automobiles	169.9	169.9	169.9	169.9	169.9	169.9	169.9	169.9	169.9	169.9	169.9	169.9	169.9	169.9	169.9	169.9
Light Trucks	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8
Heavy Trucks	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7
General Equipment	867.1	885.2	905.3	924.4	943.5	962.6	981.7	1,000.8	1,019.9	1,039.0	1,058.1	1,077.2	1,096.3	1,115.4	1,134.5	1,153.6
Data Handling Equipment	3,968.9	4,043.7	4,118.5	4,193.3	4,268.1	4,342.9	4,417.7	4,492.5	4,567.3	4,642.1	4,716.9	4,791.7	4,866.5	4,941.3	5,016.1	5,090.9
Easements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Trailers	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	412,995.1	415,758.5	420,327.2	424,067.5	427,517.2	431,016.0	434,722.6	438,568.9	442,408.8	446,334.8	450,256.5	454,171.6	458,081.0	461,985.9	465,891.1	469,796.4

Gas Plant Depreciation Rates:																
Unallocated	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Mfg Gas Production Plant	0.001605	0.001605	0.001605	0.001605	0.001605	0.001605	0.001605	0.001605	0.001605	0.001605	0.001605	0.001605	0.001605	0.001605	0.001605	0.001605
Distribution	0.001988	0.001988	0.001988	0.001988	0.001988	0.001988	0.001988	0.001988	0.001988	0.001988	0.001988	0.001988	0.001988	0.001988	0.001988	0.001988
Distribution Future	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Information System	0.010483	0.010483	0.010483	0.010483	0.010483	0.010483	0.010483	0.010483	0.010483	0.010483	0.010483	0.010483	0.010483	0.010483	0.010483	0.010483
Intangible Plant	0.016588	0.016588	0.016588	0.016588	0.016588	0.016588	0.016588	0.016588	0.016588	0.016588	0.016588	0.016588	0.016588	0.016588	0.016588	0.016588
Office Buildings	0.001713	0.001713	0.001713	0.001713	0.001713	0.001713	0.001713	0.001713	0.001713	0.001713	0.001713	0.001713	0.001713	0.001713	0.001713	0.001713
Office Furniture	0.003285	0.003285	0.003285	0.003285	0.003285	0.003285	0.003285	0.003285	0.003285	0.003285	0.003285	0.003285	0.003285	0.003285	0.003285	0.003285
Automobiles	0.010006	0.010006	0.010006	0.010006	0.010006	0.010006	0.010006	0.010006	0.010006	0.010006	0.010006	0.010006	0.010006	0.010006	0.010006	0.010006
Light Trucks	0.010103	0.010103	0.010103	0.010103	0.010103	0.010103	0.010103	0.010103	0.010103	0.010103	0.010103	0.010103	0.010103	0.010103	0.010103	0.010103
Heavy Trucks	0.007506	0.007506	0.007506	0.007506	0.007506	0.007506	0.007506	0.007506	0.007506	0.007506	0.007506	0.007506	0.007506	0.007506	0.007506	0.007506
General Equipment	0.004728	0.004728	0.004728	0.004728	0.004728	0.004728	0.004728	0.004728	0.004728	0.004728	0.004728	0.004728	0.004728	0.004728	0.004728	0.004728
Data Handling Equipment	0.003754	0.003754	0.003754	0.003754	0.003754	0.003754	0.003754	0.003754	0.003754	0.003754	0.003754	0.003754	0.003754	0.003754	0.003754	0.003754
Essentials	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Trailers	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000

<u>Gas Plant Depreciation Expense Charged to Income Statement @ 100%:</u>															
Unallocated	-45.6	-45.6	-45.6	-45.6	-45.6	-45.6	-45.6	-45.6	-45.6	-45.6	-45.6	-45.6	-45.6	-45.6	-45.6
Mfg Gas Production Plant	-49.1	-49.1	-49.1	-49.1	-49.1	-49.1	-49.1	-49.1	-49.1	-49.1	-49.1	-49.1	-49.1	-49.1	-49.1
Distribution	727.2	730.7	738.0	744.9	752.2	758.5	765.6	767.0	758.6	770.2	772.4	775.0	778.8	782.4	786.4
Distribution Future	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Intangible Plant	88.9	88.9	88.9	88.9	88.9	88.9	88.9	88.9	88.9	88.9	88.9	88.9	88.9	88.9	88.9
Office Buildings	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Office Furniture	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Data Handling Equipment	14.9	14.9	15.2	15.5	15.7	16.0	16.3	16.2	16.2	16.1	16.1	16.0	16.0	15.9	15.9
Excessments	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Trailers	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	835.5	838.9	846.5	853.7	861.3	868.2	875.2	876.5	878.1	876.7	881.6	884.3	888.1	891.7	895.5

Common Plant in Service Beginning Balance:

[illegible][illegible][illegible][illegible][illegible]

Unallocated	-	-	-	-	-	-	-	-	-	-	-	-				
Information System	68.1	67.3	66.8	66.6	66.4	66.2	66.0	67.1	66.5	67.2	66.5	66.4	70.7	70.9	72.8	94.8
Intangible Plant - Amortizations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CIMS	182.2	182.2	182.2	182.2	182.2	182.2	182.2	182.2	182.2	182.2	182.2	182.2	182.2	182.2	182.2	182.2
Retail Access Ph 3 & 4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4
Plant Field Order Route Design	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4
Nucor System	36.0	36.0	36.0	36.0	36.0	36.0	36.0	35.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0
Software Data Pipe	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5
TZVMS	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9
Total Amortizations	258.4	258.4	258.4	258.4	258.4	258.4	258.4	258.4	258.4	258.4	258.0	258.0	258.0	258.0	258.0	258.0
Office Buildings	98.0	97.9	97.9	97.8	97.7	97.7	97.6	97.6	97.5	97.4	97.4	97.8	97.7	98.3	98.3	98.0
Office Furniture	17.6	17.6	17.4	17.3	17.2	17.1	17.0	16.9	16.8	16.7	16.6	16.8	16.5	17.6	17.6	18.7
Automobiles	2.2	2.0	3.2	3.7	4.3	4.9	5.4	5.4	5.4	5.4	5.4	8.1	8.1	8.4	8.4	8.4
Light Trucks	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4
Heavy Trucks	2.3	2.4	4.2	5.9	7.7	9.5	11.3	11.3	11.3	11.3	11.3	12.9	16.8	18.5	18.9	19.8

General Equipment	2.9	2.9	6.3	9.6	13.0	16.4	19.7	19.7	19.8	19.9	20.2	20.9	22.4	22.5	22.7	23.1
Data Handling Equipment	67.0	66.8	66.7	66.5	66.4	66.2	66.1	65.9	65.6	65.5	65.3	65.2	65.0	64.9	64.7	64.7
Easements	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	536.0	535.4	540.2	545.4	550.6	555.8	561.0	561.8	560.9	561.0	564.7	566.3	556.5	559.2	561.9	561.2

Common Plant Depreciation Expense Charged to:

<u>Clearing Accounts:</u>																
Information System	68.1	67.3	66.8	66.6	66.4	66.2	66.0	67.1	66.5	67.2	66.5	66.4	70.7	70.9	72.8	94.8
Automobiles	2.2	2.6	3.2	3.7	4.3	4.9	5.4	5.4	5.4	5.4	8.1	8.1	8.1	8.4	8.4	8.4
Light Trucks	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4
Heavy Trucks	2.3	2.4	4.2	5.9	7.7	9.5	11.3	11.3	11.3	11.3	12.9	16.8	18.5	18.9	19.8	24.1
General Equipment	2.9	2.9	6.3	9.6	13.0	16.4	19.7	19.7	19.8	19.9	20.2	20.9	22.4	22.5	22.7	23.1
Total	94.9	94.6	99.9	105.3	110.8	116.3	121.8	122.9	122.3	123.1	127.1	131.5	139.0	140.1	143.1	169.8

Common Plant Depreciation Expense Allocated:

Unallocated @ 29.25%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<u>Intangible Plant - Amortizations @ 24.02%</u>																
CIMS	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8
Retail Access Ph 3 & 4	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	-	-	-	-	-	-	-
Plant Field Order Route Design	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Nucon System	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6
Software Data Pipe	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
EVMS	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
Total Amortizations	62.1	62.1	62.1	62.1	62.1	62.1	62.1	62.1	62.1	57.2	57.2	57.2	57.2	57.2	57.2	57.2
Office Buildings @ 29.25%	28.7	28.6	28.6	28.6	28.6	28.6	28.6	28.5	28.5	28.5	28.5	28.6	28.6	28.8	28.8	29.2
Office Furniture @ 29.25%	5.1	5.1	5.1	5.1	5.0	5.0	5.0	4.9	4.9	4.9	4.9	4.8	4.8	5.2	5.1	5.5
Data Handling Equipment @ 29.25%	19.5	19.5	19.5	19.5	19.4	19.4	19.3	19.3	19.2	19.2	19.2	19.1	19.1	19.0	19.0	18.9
Easements @ 29.25%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Common Depreciation Allocated	115.49	115.40	115.31	115.23	115.14	115.05	114.96	114.87	114.78	109.79	106.71	106.75	109.66	110.14	110.09	110.80

Total Gas Depreciation On Income Statement	835.5	836.9	846.5	853.7	861.3	868.2	875.2	879.5	878.1	879.7	881.8	884.3	888.1	891.7	896.5	902.2
Total Common Depreciation Alloc On Income	115.5	115.4	115.3	115.2	115.1	115.0	114.9	114.8	114.8	109.8	109.7	109.8	109.7	110.1	110.1	110.8
Total Gas Depreciation On Income Statement	951.0	954.3	961.8	968.9	976.4	983.2	990.2	991.4	992.9	989.5	991.6	994.1	997.7	1,001.8	1,006.6	1,013.0

Exhibits G-4
Schedule 4
Page 2 of 3

	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10
Gas Plant In Service Beginning Balance:												
Unallocated												
Mfg Gas Production Plant	30,537.0	30,533.9	30,530.8	30,527.7	30,524.6	30,521.5	30,518.4	30,515.3	30,512.2	30,509.1	30,506.0	30,502.9
Distribution	401,491.2	412,153.2	414,512.7	415,834.5	417,312.0	418,773.6	420,526.8	422,489.7	425,090.2	427,634.7	430,318.1	433,519.6
Distribution Future	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3
Information System	601.0	601.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0
Intangibles Plant	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2
Office Buildings	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9
Office Furniture	119.2	117.0	114.8	112.6	110.4	108.2	106.0	103.8	101.6	99.4	97.2	95.0
Automobiles	169.9	169.9	169.9	169.9	169.9	169.9	169.9	169.9	169.9	169.9	169.9	169.9
Light Trucks	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8
Heavy Trucks	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7
General Equipment	1,315.6	1,350.9	1,394.4	1,430.3	1,466.2	1,502.1	1,538.0	1,573.9	1,609.8	1,645.7	1,681.6	1,717.5
Data Handling Equipment	4,442.5	4,430.6	4,418.7	4,406.8	4,394.9	4,383.0	4,371.1	4,359.2	4,347.3	4,335.4	4,323.5	4,311.6
Easements												
Trailers												
Total	447,798.4	458,478.4	461,420.3	462,760.8	464,257.0	465,737.3	467,509.2	469,490.8	472,321.1	474,884.3	477,586.4	482,806.6

Unallocated	-	-	-	-	-	-	-	-	-	-	-	-
Mfg Gas Production Plant	0	0	0	0	0	0	0	0	0	0	0	0
Distribution	10749.4	2446.9	1409.2	1564.9	1549	1840.6	2050.3	2637.9	2631.9	2770.8	5288.9	13270.3
Distribution Future	0	0	0	0	0	0	0	0	0	0	0	0
Information System	0	556.0	0	0	0	0	0	0	0	0	0	0
Intangible Plant	-	-	-	-	-	-	-	-	-	-	-	-
Office Buildings	-	-	-	-	-	-	-	-	-	-	-	-
Office Furniture	-	-	-	-	-	-	-	211.1	-	-	-	-
Automobiles	-	-	-	-	-	-	-	-	-	-	-	-
Light Trucks	-	-	-	-	-	-	-	-	-	-	-	-
Heavy Trucks	-	-	-	-	-	-	-	-	-	-	-	-
General Equipment	35.3	43.5	35.9	35.9	35.9	35.9	35.9	35.9	35.9	35.9	35.9	35.9
Data Handling Equipment	0	0	0	0	0	0	0	0	0	0	0	0
Easements	-	-	-	-	-	-	-	-	-	-	-	-
Trailers	-	-	-	-	-	-	-	-	-	-	-	-
Total	10,784.7	3,046.4	1,445.1	1,600.8	1,584.9	1,876.5	2,086.2	2,934.9	2,667.8	2,906.7	5,324.8	13,306.2

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Unallocated												
Mfg Gas Production Plant	30,533.9	30,530.8	30,527.7	30,524.6	30,521.5	30,518.4	30,515.3	30,512.2	30,509.1	30,506.0	30,502.9	30,499.8
Distribution	412,153.2	414,512.7	415,834.5	417,312.0	418,773.6	420,526.8	422,489.7	425,090.2	427,634.7	430,318.1	435,519.6	448,702.6
Distribution Future	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3
Information System	601.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0
Intangible Plant	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2
Office Buildings	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9
Office Furniture	117.0	114.8	112.6	110.4	108.2	106.0	103.8	101.6	99.4	97.2	95.0	92.8
Automobiles	169.9	169.9	169.9	169.9	169.9	169.9	169.9	381.0	381.0	381.0	381.0	381.0
Light Trucks	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8
Heavy Trucks	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7
General Equipment	1,350.9	1,394.4	1,430.3	1,466.2	1,502.1	1,538.0	1,573.9	1,609.8	1,645.7	1,681.6	1,717.5	1,753.4
Data Handling Equipment	4,430.6	4,418.7	4,406.8	4,394.9	4,383.0	4,371.1	4,359.2	4,347.3	4,335.4	4,323.5	4,311.6	4,299.7
Easements	-	-	-	-	-	-	-	-	-	-	-	-
Trailers	-	-	-	-	-	-	-	-	-	-	-	-
Total	458,478.4	461,420.3	462,760.8	464,257.0	465,737.3	467,509.2	469,490.8	472,321.1	474,884.3	477,586.4	482,806.6	496,008.2

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Unallocated																		
Information System	11,487.2	11,813.5	12,117.5	12,027.5	13,188.9	13,175.2	13,218.5	13,497.6	13,790.7	13,744.9	13,905.5	13,972.4						
Intangible Plant	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0
Office Buildings	50,369.9	50,336.6	50,303.2	50,269.8	50,238.4	50,378.4	50,367.5	50,540.0	50,683.3	50,783.3	50,834.2	50,903.7						
Office Furniture	3,736.1	3,717.5	3,699.0	3,680.5	3,662.1	3,643.6	3,625.1	3,606.7	3,644.9	3,826.4	4,084.8	4,046.3						
Automobiles	889.2	889.2	889.2	889.2	889.2	969.6	1,140.4	1,140.4	1,170.7	1,170.7	1,193.8	1,193.8						
Light Trucks	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9						
Heavy Trucks	3,802.8	4,390.2	4,390.2	4,390.2	4,390.2	4,892.7	5,480.7	5,480.7	5,681.7	5,814.7	6,462.6	6,603.9						
General Equipment	5,577.8	5,665.5	5,665.5	5,678.7	5,717.0	5,769.3	5,837.0	6,209.6	6,227.5	6,285.0	6,421.9	6,437.1						
Data Handling Equipment	13,570.4	13,539.4	13,508.4	13,477.4	13,446.4	13,415.4	13,384.4	13,353.4	13,322.4	13,291.4	13,260.4	13,229.4						
Easements	786.0	786.0	786.0	786.0	786.0	786.0	786.0	786.0	786.0	786.0	786.0	786.0						
Total	145,606.2	146,444.7	146,665.8	146,506.1	147,625.0	148,357.0	149,146.4	149,921.3	150,814.1	151,009.4	152,236.1	152,479.4						

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Unallocated	-	-	-	-	-	-	-	-	-	-	-	-	-
Information System	96.3	95.7	98.4	101.0	100.2	109.9	109.8	110.1	112.5	114.9	114.5	115.9	
Intangible Plant - Amortizations	-	-	-	-	-	-	-	-	232.2	232.2	232.2	232.2	
CIMS	182.2	182.2	182.2	182.2	182.2	182.2	182.2	182.2	182.2	182.2	182.2	182.2	
Retail Access Ph 3 & 4	-	-	-	-	-	-	-	-	-	-	-	-	
Plant Field Order Route Design	4.4	4.4	4.4	4.4	4.4	-	-	-	-	-	-	-	
Nucon System	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	
Software Data Pipe	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	
EZVMS	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	
Total Amortizations	238.0	238.0	238.0	238.0	238.0	233.6	233.6	233.6	233.6	233.6	233.6	233.6	
Office Buildings	100.3	101.3	101.2	101.2	101.1	101.0	101.3	101.3	101.6	101.9	102.1	102.2	
Office Furniture	18.6	18.6	18.5	18.4	18.3	18.2	18.1	18.0	17.9	19.1	19.0	20.2	
Automobiles	8.4	8.4	8.4	8.4	8.4	8.4	9.4	10.8	10.8	11.1	11.1	11.3	
Light Trucks	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	
Heavy Trucks	25.0	25.8	29.1	29.1	29.1	29.1	32.4	36.3	36.3	37.7	38.6	42.9	
General Equipment	23.4	23.7	24.1	24.1	24.1	24.3	24.5	24.8	26.4	26.4	26.7	27.3	
Data Handling Equipment	64.6	64.4	64.3	64.2	64.0	63.9	63.7	63.6	63.4	63.3	63.1	63.0	
Easements	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	
Total	594.2	595.4	601.5	603.8	602.8	607.9	612.3	618.1	654.3	659.7	660.5	668.0	

Government's table presentation suggests the following:												
Clearing Accounts:												
Information System	96.3	95.7	98.4	101.0	100.2	109.9	109.8	110.1	112.5	114.9	114.5	115.9
Automobiles	8.4	8.4	8.4	8.4	8.4	8.4	9.4	10.8	10.8	11.1	11.1	11.3
Light Trucks	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4
Heavy Trucks	25.0	25.8	29.1	29.1	29.1	29.1	32.4	36.3	36.3	37.7	38.6	42.9
General Equipment	23.4	23.7	24.1	24.1	24.1	24.3	24.5	24.8	26.4	26.4	26.7	27.3
Total	172.5	173.0	179.5	182.0	181.3	191.1	195.5	201.5	203.4	209.6	210.3	216.7

Unallocated @ 29.25%	-	-	-	-	-	-	-	-	-	-	-	-
Intangible Plant - Amortizations @ 24.02%												
CIMS	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8
Retail Access Ph 3 & 4	-	-	-	-	-	-	-	-	-	-	-	-
Plant Field Order Route Design	1.1	1.1	1.1	1.1	1.1	-	-	-	-	-	-	-
Nucon System	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6
Software Data Pipe	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
EVZMS	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
Total Amortizations	57.2	57.2	57.2	57.2	57.2	56.1	56.1	56.1	56.1	56.1	56.1	56.1
Office Buildings @ 29.25%	29.3	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.7	29.8	29.9	29.9
Office Furniture @ 29.25%	5.5	5.4	5.4	5.4	5.3	5.3	5.3	5.3	5.2	5.6	5.6	5.9
Data Handling Equipment @ 29.25%	18.9	18.9	18.8	18.8	18.7	18.7	18.6	18.6	18.5	18.5	18.5	18.4
Equipment @ 29.25%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Common Depreciation Allocated	110.89	111.10	111.01	110.92	110.83	109.69	109.70	109.62	109.66	110.04	110.03	110.37

Twelve Months Ended October 30, 2010

12.661.5

Exhibits G-4
Schedule 4
Page 3 of 3

	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10
Gas Plant In Service Beginning Balance:												
Unallocated												
Mfg Gas Production Plant	30,537.0	30,533.9	30,530.8	30,527.7	30,524.6	30,521.5	30,518.4	30,515.3	30,512.2	30,509.1	30,506.0	30,502.9
Distribution	401,491.2	412,153.2	414,512.7	415,834.5	417,312.0	418,773.6	420,526.8	422,489.7	425,090.2	427,634.7	430,318.1	435,519.6
Distribution Future	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3
Information System	601.0	601.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0
Intangible Plant	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2
Office Buildings	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9
Office Furniture	119.2	117.0	114.8	112.6	110.4	108.2	106.0	103.8	101.6	99.4	97.2	95.0
Automobiles	169.9	169.9	169.9	169.9	169.9	169.9	169.9	169.9	169.9	169.9	169.9	169.9
Light Trucks	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8
Heavy Trucks	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7
General Equipment	1,315.6	1,350.9	1,394.4	1,430.3	1,466.2	1,502.1	1,538.0	1,573.9	1,609.8	1,645.7	1,681.6	1,717.5
Data Handling Equipment	4,442.5	4,430.6	4,418.7	4,406.8	4,394.9	4,383.0	4,371.1	4,359.2	4,347.3	4,335.4	4,323.5	4,311.6
Easements												
Trailers												
Total	447,798.4	458,478.4	461,420.3	462,760.8	464,257.0	465,737.3	467,509.2	469,490.8	472,321.1	474,884.3	477,586.4	482,806.6
Gas Plant Additions:												
Unallocated												
Mfg Gas Production Plant	0	0	0	0	0	0	0	0	0	0	0	0
Distribution	10749.4	2446.9	1409.2	1564.9	1549	1840.6	2050.3	2687.9	2631.9	2770.8	5288.8	13270.3
Distribution Future	0	0	0	0	0	0	0	0	0	0	0	0
Information System	0	556.0	0	0	0	0	0	0	0	0	0	0
Intangible Plant												
Office Buildings												
Office Furniture												
Automobiles								211.1				
Light Trucks												
Heavy Trucks												
General Equipment	35.3	43.5	35.9	35.9	35.9	35.9	35.9	35.9	35.9	35.9	35.9	35.9
Data Handling Equipment	0	0	0	0	0	0	0	0	0	0	0	0
Easements												
Trailers												
Total	10,784.7	3,046.4	1,445.1	1,600.8	1,584.9	1,876.5	2,086.2	2,934.9	2,667.8	2,806.7	5,324.8	13,306.2
Gas Plant Retirements:												
Unallocated												
Mfg Gas Production Plant	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
Distribution	87.4	87.4	87.4	87.4	87.4	87.4	87.4	87.4	87.4	87.4	87.4	87.4
Distribution Future	0	0	0	0	0	0	0	0	0	0	0	0
Information System	0	0	0	0	0	0	0	0	0	0	0	0
Intangible Plant												
Office Buildings												
Office Furniture	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Automobiles												
Light Trucks												
Heavy Trucks												
General Equipment												
Data Handling Equipment	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9
Easements												
Trailers												
Total	104.6	104.6	104.6	104.6	104.6	104.6	104.6	104.6	104.6	104.6	104.6	104.6
Gas Plant Ending Balance:												
Unallocated												
Mfg Gas Production Plant	30,533.8	30,530.8	30,527.7	30,524.6	30,521.5	30,518.4	30,515.3	30,512.2	30,509.1	30,506.0	30,502.9	30,499.8
Distribution	412,153.2	414,512.7	415,834.5	417,312.0	418,773.6	420,526.8	422,489.7	425,090.2	427,634.7	430,318.1	435,519.6	448,702.6
Distribution Future	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3
Information System	601.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0
Intangible Plant	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2
Office Buildings	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9
Office Furniture	117.0	114.8	112.6	110.4	108.2	106.0	103.8	101.6	99.4	97.2	95.0	92.8
Automobiles	169.9	169.9	169.9	169.9	169.9	169.9	169.9	169.9	169.9	169.9	169.9	169.9
Light Trucks	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8
Heavy Trucks	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7
General Equipment	1,350.9	1,394.4	1,430.3	1,466.2	1,502.1	1,538.0	1,573.9	1,609.8	1,645.7	1,681.6	1,717.5	1,753.4
Data Handling Equipment	4,430.6	4,418.7	4,406.8	4,394.9	4,383.0	4,371.1	4,359.2	4,347.3	4,335.4	4,323.5	4,311.6	4,298.7
Easements												
Trailers												
Total	458,478.4	461,420.3	462,760.8	464,257.0	465,737.3	467,509.2	469,490.8	472,321.1	474,884.3	477,586.4	482,806.6	496,008.2
Gas Plant Depreciation Rates:												
Unallocated	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Mfg Gas Production Plant	0.001755	0.001755	0.001755	0.001755	0.001755	0.001755	0.001755	0.001755	0.001755	0.001755	0.001755	0.001755
Distribution	0.002087	0.002087	0.002087	0.002087	0.002087	0.002087	0.002087	0.002087	0.002087	0.002087	0.002087	0.002087
Distribution Future	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Information System	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333
Intangible Plant	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Office Buildings	0.002000	0.002000	0.002000	0.002000	0.002000	0.002000	0.002000	0.002000	0.002000	0.002000	0.002000	0.002000
Office Furniture	0.004186	0.004186	0.004186	0.004186	0.004186	0.004186	0.004186	0.004186	0.004186	0.004186	0.004186	0.004186
Automobiles	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375
Light Trucks	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375

[illegible]

Common Plant Ending Balance:

Unallocated	-	-	-	-	-	-	-	-	-	-	-	-
Information System	11,487.2	11,813.5	12,117.5	12,027.5	13,188.9	13,175.2	13,218.5	13,497.6	13,790.7	13,744.9	13,905.5	13,972.4
Intangible Plant	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0
Office Buildings	50,369.9	50,336.6	50,303.2	50,269.8	50,236.4	50,203.0	50,169.6	50,136.2	50,102.8	50,069.4	50,036.0	50,002.6
Office Furniture	3,736.1	3,717.5	3,699.0	3,680.5	3,662.1	3,643.6	3,625.1	3,606.7	3,588.2	3,569.7	3,551.2	3,532.7
Automobiles	889.2	889.2	889.2	889.2	889.2	889.2	889.2	889.2	889.2	889.2	889.2	889.2
Light Trucks	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9
Heavy Trucks	3,882.8	4,390.2	4,390.2	4,390.2	4,390.2	4,390.2	4,390.2	4,390.2	4,390.2	4,390.2	4,390.2	4,390.2
General Equipment	5,577.8	5,665.5	5,665.5	5,678.7	5,717.0	5,769.3	5,837.0	5,904.7	5,972.4	6,040.1	6,107.8	6,175.5
Data Handling Equipment	13,570.4	13,539.4	13,508.4	13,477.4	13,446.4	13,415.4	13,384.4	13,353.4	13,322.4	13,291.4	13,260.4	13,229.4
Easements	786.0	786.0	786.0	786.0	786.0	786.0	786.0	786.0	786.0	786.0	786.0	786.0
Total	145,606.2	146,444.7	146,665.8	146,506.1	147,825.0	148,357.0	149,146.4	149,921.3	150,814.1	151,009.4	152,236.1	152,479.4

Common Plant Depreciation Rates:

Unallocated	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Information System	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333
Intangible Plant	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Office Buildings	0.002011	0.002011	0.002011	0.002011	0.002011	0.002011	0.002011	0.002011	0.002011	0.002011	0.002011	0.002011
Office Furniture	0.004966	0.004966	0.004966	0.004966	0.004966	0.004966	0.004966	0.004966	0.004966	0.004966	0.004966	0.004966
Automobiles	0.009493	0.009493	0.009493	0.009493	0.009493	0.009493	0.009493	0.009493	0.009493	0.009493	0.009493	0.009493
Light Trucks	0.009391	0.009391	0.009391	0.009391	0.009391	0.009391	0.009391	0.009391	0.009391	0.009391	0.009391	0.009391
Heavy Trucks	0.006632	0.006632	0.006632	0.006632	0.006632	0.006632	0.006632	0.006632	0.006632	0.006632	0.006632	0.006632
General Equipment	0.004247	0.004247	0.004247	0.004247	0.004247	0.004247	0.004247	0.004247	0.004247	0.004247	0.004247	0.004247
Data Handling Equipment	0.004749	0.004749	0.004749	0.004749	0.004749	0.004749	0.004749	0.004749	0.004749	0.004749	0.004749	0.004749
Easements	0.000127	0.000127	0.000127	0.000127	0.000127	0.000127	0.000127	0.000127	0.000127	0.000127	0.000127	0.000127

Common Plant Depreciation Expense @ 100%:

Unallocated	-	-	-	-	-	-	-	-	-	-	-	-
Information System	96.3	95.7	98.4	101.0	100.2	109.9	109.8	110.1	112.5	114.9	114.5	115.9
Intangible Plant - Amortizations	-	-	-	-	-	-	-	-	-	-	-	-
CIMS	182.2	182.2	182.2	182.2	182.2	182.2	182.2	182.2	182.2	182.2	182.2	182.2
Retail Access Ph 3 & 4	-	-	-	-	-	-	-	-	-	-	-	-
Plant Field Order Route Design	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4
Nucon System	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0
Software Data Pipe	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5
EZVMS	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9
Total Amortizations	238.0	238.0	238.0	238.0	238.0	238.0	238.0	238.0	238.0	238.0	238.0	238.0
Office Buildings	100.3	101.3	101.2	101.2	101.1	101.0	101.3	101.3	101.6	101.9	102.1	102.2
Office Furniture	18.6	18.6	18.5	18.4	18.3	18.2	18.1	18.0	17.9	17.8	17.7	17.6
Automobiles	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Light Trucks	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4
Heavy Trucks	25.0	25.8	29.1	29.1	29.1	29.1	32.4	36.3	37.7	38.6	42.9	42.9
General Equipment	23.4	23.7	24.1	24.1	24.1	24.3	24.5	24.8	26.4	26.4	26.7	27.3
Data Handling Equipment	64.6	64.4	64.3	64.2	64.0	63.9	63.7	63.6	63.4	63.3	63.1	63.0
Easements	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	594.2	595.4	601.5	603.8	602.8	607.9	612.3	618.1	624.3	629.7	635.5	641.3

Common Plant Depreciation Expense Charged to:

Clearing Accounts:												
Information System	96.3	95.7	98.4	101.0	100.2	109.9	109.8	110.1	112.5	114.9	114.5	115.9
Automobiles	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Light Trucks	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4
Heavy Trucks	25.0	25.8	29.1	29.1	29.1	29.1	32.4	36.3	37.7	38.6	42.9	42.9
General Equipment	23.4	23.7	24.1	24.1	24.1	24.3	24.5	24.8	26.4	26.4	26.7	27.3
Total	172.5	173.0	179.5	182.0	181.3	191.1	195.5	201.5	205.4	209.6	210.3	216.7

Common Plant Depreciation Expense Allocated:

Unallocated @ 29.25%	-	-	-	-	-	-	-	-	-	-	-	-
Intangible Plant - Amortizations @ 24.02%	-	-	-	-	-	-	-	-	-	-	-	-
CIMS	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8
Retail Access Ph 3 & 4	-	-	-	-	-	-	-	-	-	-	-	-
Plant Field Order Route Design	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Nucon System	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6
Software Data Pipe	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
EZVMS	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
Total Amortizations	57.2	57.2	57.2	57.2	57.2	57.2	57.2	57.2	57.2	57.2	57.2	57.2
Office Buildings @ 29.25%	29.3	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.7	29.8	29.9	29.9
Office Furniture @ 29.25%	5.5	5.4	5.4	5.4	5.3	5.3	5.3	5.3	5.2	5.2	5.1	5.0
Data Handling Equipment @ 29.25%	18.9	18.9	18.8	18.8	18.7	18.7	18.6	18.6	18.5	18.5	18.5	18.4
Easements @ 29.25%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Common Depreciation Allocated	110.89	111.10	111.01	110.92	110.83	109.69	109.70	109.62	109.66	110.04	110.03	110.37

Total Gas Depreciation On Income Statement	864.3	886.5	891.4	894.1	897.1	900.1	903.7	907.7	913.1	918.3	923.9	934.7
Total Common Depreciation Alloc On Income	110.9	111.1	111.0	110.9	110.8	109.7	109.7	109.6	109.7	110.0	110.0	110.4
Total Gas Depreciation On Income	975.2	997.6	1,002.4	1,005.0	1,007.9	1,009.8	1,013.4	1,017.3	1,022.7	1,028.4	1,033.9	1,045.0

Twelve Months Ended October 30, 2010

12,158.5

ORANGE AND ROCKLAND UTILITIES, INC.
TAXES OTHER THAN INCOME TAXES - GAS
FOR THE TWELVE MONTHS ENDED JUNE 30, 2008 &
OCTOBER 31, 2010
(\$000s)

	TWELVE MONTHS ENDED 6/30/08 PER BOOKS	NORMALIZING		TWELVE MONTHS ENDED 6/30/08 AS ADJUSTED		RATE YEAR AS ADJUSTED	PROPOSED RATE INCREASE	RATE YEAR AS ADJUSTED FOR PROPOSED RATE INCREASE
		REF.	AMOUNT	REF.	AMOUNT			
PROPERTY TAXES:								
STATE, COUNTY & TOWN - PAYMENTS	\$ 2,194		\$ -		\$ 2,194	\$ 2,540		\$ 2,540
- TAX TRUE UP (DEFERRAL)	84	20	(84)		-	-		-
VILLAGE - PAYMENTS	505		-		505	603		603
- TAX TRUE UP (DEFERRAL)	83	21	(83)		-	-		-
SCHOOL - PAYMENTS	5,650		-		5,650	6,793		6,793
- TAX TRUE UP (DEFERRAL)	(83)	22	83		-	-		-
AMORT. OF PROPERTY TAX DEFERRAL (A/C 25437)	-		-		-	(240)		(240)
PROPERTY TAX REFUNDS 05-G-1494 (A/C 254535)	(30)	23	30		-	-		-
PROPERTY TAX REFUNDS (A/C 254368 / 254369)	-		-		-	(24)		(24)
TOTAL PROPERTY TAXES	8,403		(54)		8,349	9,672		9,672
PAYROLL TAXES	1,012	24	(8)		1,004	1,121		1,121
REVENUE TAXES	2,375		-		2,375	2,433	183	2,616
OTHER TAXES:								
FRANCHISE TAX	43		-		43	45		45
ALL OTHER TAXES	22		-		22	23		23
OTHER TAXES	65		-		65	68		68
TOTAL TAXES OTHER THAN INCOME TAX	11,855		(62)		11,793	13,294	183	13,477
TOTAL TAXES OTHER EXCLUDING REVENUE TAXES	9,480		(62)		9,418	10,861	-	10,861

ORANGE AND ROCKLAND UTILITIES, INC.
STATE INCOME TAX - GAS
FOR THE TWELVE MONTHS ENDED JUNE 30, 2008 &
OCTOBER 31, 2010
(\$000s)

	TWELVE MONTHS ENDED 6/30/08 PER BOOKS	NORMALIZING ADJUSTMENTS (Schedule 7)	TWELVE MONTHS ENDED 6/30/05 AS ADJUSTED	RATE CASE ADJUSTMENTS (Schedule 7)	RATE YEAR AS ADJUSTED	PROPOSED RATE INCREASE	RATE YEAR AS ADJUSTED FOR PROPOSED RATE INCREASE
OPERATING INCOME BEFORE TAX	\$ 22,501	\$ 2,315	\$ 24,817	\$ (8,889)	\$ 15,927	\$ 17,604	\$ 33,531
SECTION I - PERMANENT DIFFERENCES							
ADD ADDITIONAL TAXABLE INCOME AND UNALLOWABLE DEDUCTIONS:							
BUSINESS MEAL EXPENSE	15	(15)	-	-	-	-	-
UNALLOWABLE COMPENSATION	62	(62)	-	-	-	-	-
TOTAL FLOW THRU ADDITIONS	77	(77)	-	-	-	-	-
DEDUCT NONTAXABLE INCOME AND ADDITIONAL ALLOWABLE DEDUCTIONS:							
INTEREST EXPENSE	10,913	(533)	10,380	80	10,460	-	10,460
MEDICARE REIMBURSEMENT	1,278	(543)	735	-	735	-	735
TOTAL FLOW THRU DEDUCTIONS	12,191	(1,076)	11,115	80	11,195	-	11,195
PRETAX INCOME	10,387	3,314	13,702	(8,969)	4,732	17,604	22,336
SECTION II - NORMALIZED ITEMS							
ADD ADDITIONAL TAXABLE INCOME AND UNALLOWABLE DEDUCTIONS:							
BOOK DEPRECIATION - EXPENSE	9,401	-	9,401	1,249	10,650	-	10,650
- CHARGED TO CLEARING	947	-	947	1,137	2,084	-	2,084
AMORTIZATION - COMPUTER SOFTWARE	1,506	-	1,506	(827)	679	-	679
VEHICLE LEASE EXPENSE OVER TAX DEPRECIATION	180	-	180	(169)	11	-	11
CAPITALIZED INTEREST	358	(358)	-	-	-	-	-
GENERAL LIABILITY INSURANCE	21	(21)	-	-	-	-	-
WORKMEN'S COMPENSATION	48	(48)	-	-	-	-	-
EXCESS OF BOOK RESERVE OVER UB WRITEOFFS	323	(323)	-	-	-	-	-
INCREASE IN DEFERRED FUEL COST	10,928	-	10,928	(5,167)	5,761	-	5,761
AMORTIZATION OF RATE CASE COST	17	-	17	1	18	-	18
AMORTIZATION OF BOND REDEMPTION COSTS	83	-	83	-	83	-	83
AMORTIZATION OF RECOVERED MTA TAX	26	(26)	-	-	-	-	-
MEDICARE REIMBURSEMENT	524	-	524	(947)	(423)	-	(423)
POST EMPLOYMENT BENEFITS EXPENSE	3,819	-	3,819	(499)	3,320	-	3,320
DEFERRED STATE INCOME TAX NON DEDUCTIBLE	131	(131)	-	-	-	-	-
CONTRIBUTIONS IN AID OF CONSTRUCTION	306	-	306	379	685	-	685
ENVIRONMENTAL RESERVE	21	-	21	-	21	-	21
REVENUE SUBJECT TO REFUND	538	(538)	-	-	-	-	-
UNALLOWABLE BOOK PENSION EXPENSE	11,181	-	11,181	(3,515)	7,666	-	7,666
LOW INCOME/ CUSTOMER OUTREACH	824	(624)	-	-	-	-	-
GAS STRANDED COSTS SURCHARGE RECOVERIES	915	(915)	-	-	-	-	-
PROPERTY TAX REFUND - NET 461H	154	(154)	-	-	-	-	-
TOTAL NORMALIZED ADDITIONS	42,051	(3,138)	38,913	(8,358)	30,555	-	30,555
DEDUCT NONTAXABLE INCOME AND ADDITIONAL ALLOWABLE DEDUCTIONS:							
NYS TAX DEPRECIATION - EXISTING BOOK RATES	15,285	-	15,285	5,865	21,130	-	21,130
SECTION 263A DEDUCTION (CAPITALIZED OVERHEAD)	5,970	-	5,970	102	6,072	-	6,072
COST OF REMOVAL	1,082	-	1,082	(397)	685	-	685
TAX OVER BOOK - BH LEASE	13	(13)	-	-	-	-	-
LIEN DATE PROPERTY TAX DEDUCTION	274	-	274	(176)	98	-	98
AFUDC	296	(296)	-	-	-	-	-
LOSS ON DISPOSITION OF PROPERTY	174	-	174	(1)	173	-	173
PENSION FUNDING	10,060	-	10,060	(1,712)	8,348	-	8,348
SUPPLEMENTAL PENSION	148	-	148	377	525	-	525
OPEB FUNDING	2,779	-	2,779	(103)	2,676	-	2,676
AMORTIZATION OF CONSERVATION COSTS	68	-	68	-	68	-	68
LTIP AND STOCK OPTIONS	23	(23)	-	-	-	-	-
RESERVE FOR MEDICAL INSURANCE	93	(93)	-	-	-	-	-
INTEREST - ALGONQUIN CAPACITY PAYMENT	8	(8)	-	-	-	-	-
MERCHANT FUNCTION CHARGE	1	(1)	-	-	-	-	-
PHASE IN OF RATE RELIEF 05-G-1494	679	(679)	-	-	-	-	-
MTA TAX DEFERRED	58	(58)	-	-	-	-	-
GAS IN STORAGE CARRYING CHARGE	746	-	746	(176)	570	-	570
ENVIRONMENTAL COST - QER EXPEND. SECT. 198	991	-	991	-	991	-	991
TOTAL	38,728	(1,171)	37,557	3,779	41,336	-	41,336
TAXABLE INCOME OR (LOSS)	13,710	1,347	15,058	(21,106)	(6,049)	17,604	11,555
SUMMARY OF STATE INCOME TAXES							
CURRENT STATE INCOME TAXES @ 7.1%	973	96	1,069	(1,499)	(429)	1,250	820
DEFERRED STATE INCOME TAXES @ 7.1%	(236)	140	(96)	862	765	-	765
TOTAL CURRENT PERIOD SIT	737	236	973	(637)	336	1,250	1,585
MTA TAX @ 1.53%	210	(210)	-	-	-	-	-
DEFERRED STATE MTA TAXES @ 1.53%	(51)	51	-	-	-	-	-
PRIOR PERIOD OVER / UNDER ACCRUAL	(15)	15	-	-	-	-	-
NYS INCOME TAX	\$ 881	\$ 92	\$ 973	\$ (637)	\$ 336	\$ 1,250	\$ 1,585
(Incr.) / Decr. to Rate Base - Change in Deferred SIT	\$ (236)	\$ 140	\$ (96)	\$ 862	\$ 765	\$ -	\$ 765
- FIT on SIT	83	(49)	34	(302)	(268)	-	(268)
Net Rate Base (Increase) / Decrease	\$ (153)	\$ 91	\$ (62)	\$ 560	\$ 497	\$ -	\$ 497

ORANGE AND ROCKLAND UTILITIES, INC.
FEDERAL INCOME TAX - GAS
FOR THE TWELVE MONTHS ENDED JUNE 30, 2007 &
OCTOBER 31, 2010
(\$000s)

	TWELVE MONTHS ENDED 6/30/05 PER BOOKS	NORMALIZING ADJUSTMENTS (Schedule 7)	TWELVE MONTHS ENDED 6/30/05 AS ADJUSTED	RATE CASE ADJUSTMENTS (Schedule 7)	RATE YEAR AS ADJUSTED	PROPOSED RATE INCREASE	RATE YEAR AS ADJUSTED FOR PROPOSED RATE INCREASE
OPERATING INCOME BEFORE TAX	\$ 22,501	\$ 2,315	\$ 24,817	\$ (8,889)	\$ 15,927	\$ 17,604	\$ 33,531
NYS INCOME TAX	881	92	973	(637)	336	1,250	1,585
BOOK INCOME BEFORE FIT	21,620	2,223	23,844	(8,252)	15,591	16,354	31,946
SECTION I - FLOW THRU ITEMS							
ADD ADDITIONAL TAXABLE INCOME AND							
UNALLOWABLE DEDUCTIONS:							
BOOK DEPRECIATION - EXPENSE	9,401	-	9,401	1,249	10,650	-	10,650
- CHARGED TO CLEARING	947	-	947	1,137	2,084	-	2,084
CAPITALIZED INTEREST	358	(358)	-	-	-	-	-
EXCESS OF BOOK RESERVE OVER UB WRITEOFFS	323	(323)	-	-	-	-	-
GENERAL LIABILITY INSURANCE	21	(21)	-	-	-	-	-
WORKMEN'S COMPENSATION	48	(48)	-	-	-	-	-
BUSINESS MEAL EXPENSE	15	(15)	-	-	-	-	-
UNALLOWABLE COMPENSATION	62	(62)	-	-	-	-	-
TOTAL FLOW THRU ADDITIONS	11,175	(827)	10,348	2,386	12,734	-	12,734
DEDUCT NONTAXABLE INCOME AND ADDITIONAL							
ALLOWABLE DEDUCTIONS:							
INTEREST EXPENSE	10,913	(533)	10,380	80	10,460	-	10,460
STATUTORY DEPRECIATION - CURRENT BOOK RATE	9,136	-	9,136	2,350	11,486	-	11,486
- PROPOSED BOOK RATE	-	-	-	(335)	(335)	-	(335)
COST OF REMOVAL	1,082	-	1,082	(397)	685	-	685
MEDICARE REIMBURSEMENT	1,278	(543)	735	-	735	-	735
LIEN DATE PROPERTY TAX DEDUCTION	274	-	274	(176)	98	-	98
AFUDC	296	(296)	-	-	-	-	-
LOSS ON DISPOSITION OF PROPERTY	174	-	174	(1)	173	-	173
TOTAL FLOW THRU DEDUCTIONS	23,153	(1,372)	21,781	1,521	23,302	-	23,302
PRETAX INCOME	9,642	2,768	12,411	(7,387)	5,023	16,354	21,378
SECTION II - NORMALIZED ITEMS							
ADD ADDITIONAL TAXABLE INCOME AND							
UNALLOWABLE DEDUCTIONS:							
AMORTIZATION - COMPUTER SOFTWARE	1,506	-	1,506	(827)	679	-	679
VEHICLE LEASE EXPENSE OVER TAX DEPRECIATION	180	-	180	(169)	11	-	11
INCREASE IN DEFERRED FUEL COST	10,928	-	10,928	(5,167)	5,761	-	5,761
AMORTIZATION OF RATE CASE COST	17	-	17	1	18	-	18
AMORTIZATION OF BOND REDEMPTION COSTS	83	-	83	-	83	-	83
AMORTIZATION OF RECOVERED MTA TAX	26	(26)	-	-	-	-	-
MEDICARE REIMBURSEMENT	524	-	524	(947)	(423)	-	(423)
POST EMPLOYMENT BENEFITS EXPENSE	3,819	-	3,819	(499)	3,320	-	3,320
DEFERRED STATE INCOME TAX NON DEDUCTIBLE	131	(227)	(96)	862	766	-	766
CONTRIBUTIONS IN AID OF CONSTRUCTION	306	-	306	379	685	-	685
ENVIRONMENTAL RESERVE	21	-	21	-	21	-	21
REVENUE SUBJECT TO REFUND	538	(538)	-	-	-	-	-
UNALLOWABLE BOOK PENSION EXPENSE	11,181	-	11,181	(3,515)	7,666	-	7,666
LOW INCOME/ CUSTOMER OUTREACH	624	(624)	-	-	-	-	-
GAS STRANDED COSTS SURCHARGE RECOVERIES	915	(915)	-	-	-	-	-
PROPERTY TAX REFUND - NET 461H	154	(154)	-	-	-	-	-
TOTAL NORMALIZED ADDITIONS	30,953	(2,484)	28,469	(9,882)	18,587	-	18,587
DEDUCT NONTAXABLE INCOME AND ADDITIONAL							
ALLOWABLE DEDUCTIONS:							
TAX DEPRECIATION (NORM) - ADR/ACRS/MACRS	6,129	-	6,129	2,805	8,934	-	8,934
- PROPOSED BOOK RATE	-	-	-	335	335	-	335
SECTION 263A DEDUCTION (CAPITALIZED OVERHEAD)	5,970	-	5,970	102	6,072	-	6,072
TAX OVER BOOK - BH LEASE	13	(13)	-	-	-	-	-
PENSION FUNDING	10,060	-	10,060	(1,712)	8,348	-	8,348
SUPPLEMENTAL PENSION	148	-	148	377	525	-	525
OPEB FUNDING	2,779	-	2,779	(103)	2,676	-	2,676
AMORTIZATION OF CONSERVATION COSTS	68	-	68	-	68	-	68
LTIIP AND STOCK OPTIONS	23	(23)	-	-	-	-	-
RESERVE FOR MEDICAL INSURANCE	93	(93)	-	-	-	-	-
INTEREST - ALGONQUIN CAPACITY PAYMENT	8	(8)	-	-	-	-	-
MERCHANT FUNCTION CHARGE	1	(1)	-	-	-	-	-
PHASE IN OF RATE RELIEF 05-G-1494	679	(679)	-	-	-	-	-
MTA TAX DEFERRED	58	(58)	-	-	-	-	-
GAS IN STORAGE CARRYING CHARGE	746	-	746	(176)	570	-	570
ENVIRONMENTAL COST - QER EXPEND. SECT. 198	991	-	991	-	991	-	991
TOTAL	27,766	(875)	26,891	1,628	28,519	-	28,519
TAXABLE INCOME OR (LOSS)	12,829	1,159	13,989	(18,897)	(4,909)	16,354	11,446
SUMMARY OF FEDERAL INCOME TAXES							
CURRENT FEDERAL INCOME TAXES	4,490	406	4,896	(6,814)	(1,718)	5,724	4,006
DEFERRED FEDERAL INCOME TAXES	(1,115)	563	(552)	4,028	3,476	-	3,476
AMORTIZATION OF DEFERRED FIT - 263A	(419)	-	(419)	69	(350)	-	(350)
TOTAL CURRENT PERIOD FIT	2,956	969	3,925	(2,517)	1,408	5,724	7,132
PRIOR YEARS (OVER)/UNDER ACCRUAL	(179)	179	-	-	-	-	-
FEDERAL INCOME TAX EXPENSE	2,777	1,148	3,925	(2,517)	1,408	5,724	7,132
(Incr.) / Decr. to Rate Base - Change in Def. FIT - Depr.	\$ 4,239	\$ (5)	\$ 4,235	\$ 1,135	\$ 5,369	\$ -	\$ 5,369
Decrease - Amortization of Deferred FIT - Depr	(590)	-	(590)	349	(242)	-	(242)
Net Rate Base (Increase) / Decrease	\$ 3,649	\$ (5)	\$ 3,645	\$ 1,484	\$ 5,127	\$ -	\$ 5,127

EXHIBIT G-4
SCHEDULE 8

Interest Expense - Calculated From Rate Base
Twelve Months Ending 6/30/08 & 10/31/2010
Thousands of Dollars

	<u>June 30, 2008</u>	<u>October 31, 2010</u>
Average Earnings Base	\$259,709	\$261,760
(+) Interest Bearing CWIP (Test Year Average)	5,687	5,687
(-) Dividends Declared - Gas Portion	<u>0</u>	<u>0</u>
Total	265,396	267,447
Interest Cost Factor (LTD + STD + Customer Deposits)	<u>3.91%</u>	<u>3.91%</u>
Allowable Interest Expense Calculated From Rate Base	<u>\$10,380</u>	<u>\$10,460</u>

Orange and Rockland Utilities, Inc.
Gas Operations
Summary of Normalization Adjustments
For the Twelve Months Ended June 30, 2008
(\$000's)

Exhibit G-4
Schedule 9
Page 1 of 1

	<u>Amount</u>
<u>Operating Revenues:</u>	
(1) To eliminate billing and payment processing (Retail Access) included in firm revenues	(586)
(2) To eliminate the phased-in rate increase pursuant to gas case 05-G-1494	(509)
(3) To correct test year gas service revenues (reconnects, accommodation)	133
(4) To reflect a three-year average of sales of M&S	12
(5) To reflect a 3 year average of bad check charges	(1)
(6) To eliminate amortization of NYS tax rate change	39
(7) To eliminate gas hedging program - Interest	27
(8) To normalize purchased gas expense associated with power generation passback	(720)
(9) To eliminate winter bundled sales	(443)
(10) To normalize merchant function charge (true-up)	(1)
(11) To eliminate gas R&D recovery deferral	1,009
(12) To eliminate gas peak shaving	2
(13) To eliminate an out of period adjustment in the historic year	(17)
(14) To normalize 2007 penalties for customer service surveys	100
(15) To eliminate expiring passback gas performance incentive 05-G-1494	(20)
(16) To eliminate expiring SIT passback revenues	(678)
(17) To eliminate expiring SIT passback benefit rate differential	(55)
(18) To eliminate expiring 2007 penalties for line losses	1,030
	<u>(678)</u>
<u>Operating Expenses:</u>	
(19) To adjust other non-fuel O&M	<u>(2,931)</u>
<u>Taxes Other Than Income Taxes</u>	
(20) To eliminate current true ups of state, county and town taxes	(84)
(21) To eliminate current true ups of village taxes	(83)
(22) To eliminate current true ups of school taxes	83
(23) To eliminate expiring amortization	30
(24) To eliminate expiring amortization of payroll tax	(8) <u>(62)</u>
<u>State Income Tax:</u>	
(25) To reduce the provision for State Income Taxes related to tax adjustments normalized for rate purposes (i.e., interest synchronization)	96
(26) To eliminate deferred taxes associated with book / tax timing differences normalized for rate purposes	140
(27) To eliminate the MTA Tax	(210)
(28) To eliminate the deferred MTA Tax	51
(29) To reflect prior period over/under accrual	15 <u>92</u>
<u>Federal Income Tax:</u>	
(30) To reduce the provision for Federal Income Taxes related to tax adjustments normalized for rate purposes (i.e., interest synchronization)	406
(31) To eliminate deferred taxes associated with book / tax timing differences normalized for rate purposes	563
(32) To eliminate non-recurring prior period adjustments	179 <u>1,148</u>
<u>Gas Rate Base:</u>	
(33) To adjust Gas Rate Base (See Exhibit G-2, Summary)	<u>19,615</u>

ORANGE AND ROCKLAND UTILITIES, INC.
Gas Operations
Fund Requirements and Sources
For the Twelve Months Ended October 31, 2010
(\$000's)

	<u>ORU</u> <u>Consolidated</u>	<u>ORU Gas</u> <u>Allocated</u>
<u>Sources of Funds:</u>		
Internal		
Change in Retained Earnings	\$ 22,546	\$ 5,286
Book Depreciation	43,406	10,650
Deferred Fuel	6,163	5,761
Amortizations (Net of Deferrals)	13,831	3,585
Deferred Income Taxes - Federal & State	11,664	3,891
Allowance for Funds Used During Construction	(2,919)	(296)
All Other	(28,355)	(9,474)
Total Internal Sources of Funds	<u>66,335</u>	<u>19,402</u>
External		
Long Term Debt	135,000	39,488
Common Stock	10,000	2,925
Short Term Debt	-	-
Total External Sources of Funds	<u>145,000</u>	<u>42,413</u>
Total Sources	<u>\$ 211,335</u>	<u>\$ 61,815</u>
<u>Application of Funds:</u>		
Construction Expenditures (Net of AFUDC)	\$ 159,433	\$ 46,634
Bond Maturities	55,000	16,088
Short Term Debt	(3,098)	(906)
Total Application of Funds	<u>\$ 211,335</u>	<u>\$ 61,815</u>

ORANGE AND ROCKLAND UTILITIES, INC.

INDEX OF SCHEDULES

Gas Operating Expenses

<u>SCHEDULE</u>	<u>TITLE OF SCHEDULE</u>	<u>WITNESS</u>
Summary	Summary of Gas Operating Expenses	Various
1	Purchased Gas Costs	P. Olmsted
2	Direct Labor	Accounting Panel
3	Shared Services	"
4	Employee & Other Insurance Costs	"
5	Regulatory Costs and Amortizations	Accounting Panel / J. Quin
6	Pensions and OPEBs	Accounting Panel
7	Uncollectible Costs	"
8	MGP Sites & Environmental Costs	"
9	Gas Department	R. Diloreto / D. Kennedy
10	Regulatory Commission Expenses	Accounting Panel
11	Other O&M Costs	"

ORANGE AND ROCKLAND UTILITIES, INC.
Gas Operating Expenses
Functional Distribution
(\$000s)

EXHIBIT G-5
SUMMARY
PAGE 1 of 3

TWELVE MONTHS ENDED

Account Group	Per Books 6/30/08	Normalizing Adjustments	Program Changes	Labor Escalation	General Escalation	Other Escalation	Rate Year 10/31/10
Production & Purchases							
Operation	157,662	(1,510)	(11,130)	28	13	0	145,063
Maintenance	128	0	2	3	1	0	133
Joint Expense	0	0	0	0	0	0	0
Total	157,790	(1,510)	(11,128)	31	13	0	145,196
Transmission							
Operation	0	0	0	0	0	0	0
Maintenance	0	0	0	0	0	0	0
Joint Expense	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0
Distribution							
Operation	11,244	7	1,255	586	182	0	13,274
Maintenance	6,728	0	288	366	89	0	7,471
Joint Expense	0	0	0	0	0	0	0
Total	17,972	7	1,543	952	271	0	20,745
Customer Accounts	6,212	(26)	79	229	92	0	6,586
Customer Service	1,992	(166)	108	54	37	0	2,025
Sales Promotion	0	9	0	0	0	0	9
Administrative & General							
Operation	25,628	(1,245)	273	408	214	694	25,972
Maintenance	115	0	1	2	5	0	123
Joint Expense	0	0	0	0	0	0	0
Total	25,743	(1,245)	274	410	219	694	26,094
Total Gas Operating Expenses	209,709	(2,931)	(9,124)	1,676	632	694	200,655

ORANGE AND ROCKLAND UTILITIES, INC.
Functional Distribution
(\$000s)

EXHIBIT G-5
SUMMARY
PAGE 2 of 3

TWELVE MONTHS ENDED							
	Per Books 6/30/08	Normalizing Adjustments	Program Changes	Labor Escalation	General Escalation	Other Escalation	Rate Year 10/31/10
<u>Operating Expenses</u>							
Sch. 1 - Purchased Gas Costs	157,155	(1,503)	(11,332)	0	8	0	144,328
Sch. 2 - Direct Labor (Excl. Shared Services)	20,326	(163)	892	1,463	0	0	22,518
Sch. 3 - Shared Services	3,842	0	0	138	0	143	4,123
Sch. 4 - Employee Insurance / Welfare Costs	3,912	(364)	(146)	19	18	550	3,989
Sch. 5 - Regulatory Costs and Amortizations	1,099	(156)	25	0	12	0	979
Sch. 6- Pensions and OPEBS	11,970	(999)	82	57	0	0	11,111
Sch. 7 - Uncollectible Accounts	1,271	(26)	(60)	0	0	0	1,185
Sch. 8 - MGP Sites and West Nyack Environmental Costs	1,558	0	154	0	91	0	1,803
Sch. 9 - Retail Access	254	0	1,196	0	50	0	1,500
Sch. 10 - Regulatory Commission Expenses	639	0	65	0	37	0	741
Sch. 11 - Other O&M Costs							
Advertising	3	138	0	0	7	0	148
Building Services	575	0	0	0	30	0	605
Information Technology Solutions	851	0	0	0	44	0	895
Legal & Other Professional Services	314	0	0	0	16	0	330
Rents	36	0	0	0	2	0	38
Telecommunications	283	0	0	0	15	0	297
Transportation	1,445	0	0	0	75	0	1,520
Materials and Supplies	465	0	0	0	24	0	489
Corporate Fiscal	193	142	0	0	17	0	352
Other O&M	3,518	0	0	0	183	0	3,701
Total Other O&M	7,682	280	0	0	415	0	8,377
Total Operating Expenses	209,709	(2,931)	(9,124)	1,676	632	694	200,655

ORANGE AND ROCKLAND UTILITIES, INC.
Gas Operating Expenses
Normalization Adjustments
(\$000s)

EXHIBIT G-5
SUMMARY
PAGE 3 of 3

Schedule 1 - Purchased Gas Costs	
To eliminate gas line loss incentive	\$ (1,030)
To eliminate incentive related to interruptibles	247
To defer purchased gas expense associated with power generation passback	(729)
	<u>(1,503)</u>
Schedule 2 - Direct Labor (Excl. Shared Services)	<u>(163)</u>
Schedule 4 - Employee and Other Insurance Costs	22
To eliminate restricted stock	8
To annualize property insurance premiums paid during the Test Year	(41)
To reflect a three-year average of self-insured General Liability claim payments	(353)
To reflect a three-year average of self-insured Workmen's Compensation claim payments	<u>(364)</u>
Schedule 5 - Regulatory Costs and Amortizations	10
To eliminate expiring amortization of Research and Development (188102)	68
To eliminate expiring amortization of Prior Conservation Fund (254403)	(200)
To eliminate current level of spending in Outreach & Education	(34)
To eliminate expiring amortization of Low Income Programs - Prior Period	<u>(156)</u>
Schedule 6- Pensions and OPEBS	(205)
To correct amortization of pensions	(300)
To reflect amortization of Pension Interest	(494)
To correct amortization of Medicare Part D	<u>(999)</u>
Schedule 7 - Uncollectible Accounts	(17)
To reflect Customer Accounts Receivable write-offs	(17)
To reflect Sundry Accounts Receivable write-offs	<u>(17)</u>
Schedule 11 - Other O&M Costs	138
To reflect a three-year average of Advertising expenses	142
To reflect a three-year average of Corporate Fiscal expenses	<u>280</u>

ORANGE AND ROCKLAND UTILITIES, INC.
Gas Operating Expenses
Purchased Gas Costs
(000s)

Exhibit G-5
Schedule 1
Page 1 of 2

TWELVE MONTHS ENDED

Account Group	Per Books 6/30/08	Normalizing Adjustments	Program Changes	Labor Escalation	General Escalation	Other Escalation	Rate Year 10/31/10
Production & Purchases							
Operation	157,077	(1,503)	(11,332)	0	8	0	144,250
Maintenance	78	0	0	0	0	0	78
Joint Expense	0	0	0	0	0	0	0
Total	<u>157,155</u>	<u>(1,503)</u>	<u>(11,332)</u>	<u>0</u>	<u>8</u>	<u>0</u>	<u>144,328</u>
Transmission							
Operation	0			0	0	0	0
Maintenance	0			0	0	0	0
Joint Expense	0			0	0	0	0
Total	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>
Distribution							
Operation	0			0	0	0	0
Maintenance	0			0	0	0	0
Joint Expense	0			0	0	0	0
Total	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>
Customer Accounts	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>
Customer Service	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>
Sales Promotion	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>
Administrative & General							
Operation	0			0	0	0	0
Maintenance	0			0	0	0	0
Joint Expense	0			0	0	0	0
Total	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>
Total Gas Operating Expenses	<u>157,155</u>	<u>(1,503)</u>	<u>(11,332)</u>	<u>0</u>	<u>8</u>	<u>0</u>	<u>144,328</u>

ORANGE AND ROCKLAND UTILITIES, INC.
Gas Operating Expenses
Purchased Gas Costs
(\$000s)

EXHIBIT G-5
SCHEDULE 1
PAGE 2 of 2

TWELVE MONTHS ENDED							
ITEM	Per Books 6/30/08	Normalizing Adjustments	Program Changes	Labor Escalation	General Escalation	Other Escalation	Rate Year 10/31/10
Purchased Gas Costs	146,010	0	(7,607)	0	0	0	138,403
Gas Line Loss Incentive	1,030	(1,030)	0	0	0	0	0
Interruptible Benefits Retained	(247)	247	0	0	0	0	0
Deferred Purchased Gas Expense	10,206	(720)	(3,725)	0	0	0	5,761
Other Gas Supply Costs	156	0	0	0	8	0	164
	<u>157,155</u>	<u>(1,503)</u>	<u>(11,332)</u>	<u>0</u>	<u>8</u>	<u>0</u>	<u>144,328</u>

ORANGE AND ROCKLAND UTILITIES, INC.
Gas Operating Expenses
Direct Labor
(\$000s)

EXHIBIT G-5
SCHEDULE 2
PAGE 1 of 2

TWELVE MONTHS ENDED

Account Group	Per Books 6/30/08	Normalizing Adjustments	Program Changes	Labor Escalation	General Escalation	Other Escalation	Rate Year 10/31/10
Production & Purchases							
Operation	384	0	17	28	0	0	429
Maintenance	39	0	2	3	0	0	44
Joint Expense	0	0	0	0	0	0	0
Total	423	0	19	31	0	0	473
Transmission							
Operation	0	0	0	0	0	0	0
Maintenance	0	0	0	0	0	0	0
Joint Expense	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0
Distribution							
Operation	8,161	0	359	586	0	0	9,106
Maintenance	5,093	0	223	366	0	0	5,682
Joint Expense	0	0	0	0	0	0	0
Total	13,253	0	582	952	0	0	14,787
Customer Accounts	3,175	0	139	229	0	0	3,543
Customer Service	750	0	33	54	0	0	837
Sales Promotion	0	0	0	0	0	0	0
Administrative & General							
Operation	2,703	(163)	118	195	0	0	2,853
Maintenance	21	0	1	2	0	0	24
Joint Expense	0	0	0	0	0	0	0
Total	2,725	(163)	119	197	0	0	2,878
Total Gas Operating Expenses	20,326	(163)	892	1,463	0	0	22,518

ORANGE AND ROCKLAND UTILITIES, INC.
Gas Operating Expenses
Direct Labor
(\$000s)

EXHIBIT G-5
SCHEDULE 2
PAGE 2 of 2

TWELVE MONTHS ENDED

ITEM	Per Books 6/30/08	Normalizing Adjustments	Program Changes	Labor Escalation	General Escalation	Other Escalation	Rate Year 10/31/10
<u>Total Corporate</u>							
Weekly (Incl. P/T & Temps.)	59,630	0	732	3,905	0	0	64,267
Monthly	44,609	(732)	953	3,537	0	0	48,367
 Total	<u>104,239</u>	<u>(732)</u>	<u>1,685</u>	<u>7,442</u>	<u>0</u>	<u>0</u>	<u>112,634</u>
 <u>Distribution</u>							
Electric Expense	42,606	(395)	80	3,121	0	0	45,412
Gas Expense	20,326	(163)	891	1,464	0	0	22,518
Construction	15,515	0	672	1,046	0	0	17,233
Subsidiary Companies	14,181	(174)	42	1,035	0	0	15,084
All Other	11,611	0	0	776	0	0	12,387
 Total	<u>104,239</u>	<u>(732)</u>	<u>1,685</u>	<u>7,442</u>	<u>0</u>	<u>0</u>	<u>112,634</u>

ORANGE AND ROCKLAND UTILITIES, INC.
Gas Operating Expenses
Shared Services
(\$000s)

EXHIBIT G-5
SCHEDULE 3
PAGE 1 of 2

TWELVE MONTHS ENDED

Account Group	Per Books 6/30/08	Normalizing Adjustments	Program Changes	Labor Escalation	General Escalation	Other Escalation	Rate Year 10/31/10
Production & Purchases							
Operation	0			0	0	0	0
Maintenance	0			0	0	0	0
Joint Expense	0			0	0	0	0
Total	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>
Transmission							
Operation	0			0	0	0	0
Maintenance	0			0	0	0	0
Joint Expense	0			0	0	0	0
Total	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>
Distribution							
Operation	0			0	0	0	0
Maintenance	0			0	0	0	0
Joint Expense	0			0	0	0	0
Total	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>
Customer Accounts	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>
Customer Service	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>
Sales Promotion	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>
Administrative & General							
Operation	3,842	0	0	138	0	143	4,123
Maintenance	0			0	0	0	0
Joint Expense	0			0	0	0	0
Total	<u>3,842</u>	<u>0</u>	<u>0</u>	<u>138</u>	<u>0</u>	<u>143</u>	<u>4,123</u>
Total Gas Operating Expenses	<u>3,842</u>	<u>0</u>	<u>0</u>	<u>138</u>	<u>0</u>	<u>143</u>	<u>4,123</u>

ORANGE AND ROCKLAND UTILITIES, INC.
Gas Operating Expenses
Shared Services
(\$000s)

EXHIBIT G-5
SCHEDULE 3
PAGE 2 of 2

TWELVE MONTHS ENDED

ITEM	Per Books 6/30/08	Normalizing Adjustments	Program Changes	Labor Escalation	General Escalation	Other Escalation	Rate Year 10/31/10
<u>Total Corporate</u>							
Allocated:							
Labor	8,403	0	0	600	0	0	9,003
Fringes	3,345	0	0	0	0	626	3,971
Expenses	5,006	0	0	0	265	0	5,271
Direct Expense	0	0	0	0	0	0	0
Total	<u>16,754</u>	<u>0</u>	<u>0</u>	<u>600</u>	<u>265</u>	<u>626</u>	<u>18,245</u>
<u>O&R Gas</u>							
Allocated:							
Labor	1,927	0	0	138	0	0	2,065
Expense	767	0	0	0	0	143	910
Fringes	1,148	0	0	0	0	0	1,148
Direct Expense	0	0	0	0	0	0	0
0							
Total	<u>3,842</u>	<u>0</u>	<u>0</u>	<u>138</u>	<u>0</u>	<u>143</u>	<u>4,123</u>

ORANGE AND ROCKLAND UTILITIES, INC.
Gas Operating Expenses
Employee & Other Insurance Costs
(\$000s)

EXHIBIT G-5
SCHEDULE 4
PAGE 1 of 2

TWELVE MONTHS ENDED

Account Group	Per Books 6/30/08	Normalizing Adjustments	Program Changes	Labor Escalation	General Escalation	Other Escalation	Rate Year 10/31/10
Production & Purchases							
Operation	0			0	0	0	0
Maintenance	0			0	0	0	0
Joint Expense	0			0	0	0	0
Total	0	0	0	0	0	0	0
Transmission							
Operation	0			0	0	0	0
Maintenance	0			0	0	0	0
Joint Expense	0			0	0	0	0
Total	0	0	0	0	0	0	0
Distribution							
Operation	0			0	0	0	0
Maintenance	0			0	0	0	0
Joint Expense	0			0	0	0	0
Total	0	0	0	0	0	0	0
Customer Accounts	0	0	0	0	0	0	0
Customer Service	0	0	0	0	0	0	0
Sales Promotion	0	0	0	0	0	0	0
Administrative & General							
Operation	3,912	(364)	(146)	19	18	550	3,989
Maintenance	0			0	0	0	0
Joint Expense	0			0	0	0	0
Total	3,912	(364)	(146)	19	18	550	3,989
Total Gas Operating Expenses	3,912	(364)	(146)	19	18	550	3,989

ORANGE AND ROCKLAND UTILITIES, INC.
Gas Operating Expenses
Employee & Other Insurance Costs
(\$000s)

EXHIBIT G-5
SCHEDULE 4
PAGE 2 of 2

TWELVE MONTHS ENDED							
<u>O&R Gas Expense</u>	<u>Per Books 6/30/08</u>	<u>Normalizing Adjustments</u>	<u>Program Changes</u>	<u>Labor Escalation</u>	<u>General Escalation</u>	<u>Other Escalation</u>	<u>Rate Year 10/31/10</u>
Health and Life Insurance Costs	4,557	0	0	0	0	852	5,409
Capitalized/Recovered/Contribution	(1,614)	0	0	0	0	(302)	(1,916)
1% Productivity (Health Ins./Pensions)	0	0	(146)	0	0	0	(146)
Training, HR Admin., Safety Shoes	226	0	0	0	12	0	238
Restricted Stock	(22)	22	0	0	0	0	0
Property Insurance	111	8	0	0	6	0	125
General Liability							
Claims	74	(41)	0	2	0	0	35
Ins. Premiums	64	0	0	5	0	0	69
Workmen's Compensation							
Claims	685	(500)	0	13	0	0	198
Ins. Premiums	45	0	0	3	0	0	48
Capital	(214)	147	0	(5)	0	0	(72)
Total	<u>3,912</u>	<u>(364)</u>	<u>(146)</u>	<u>19</u>	<u>18</u>	<u>550</u>	<u>3,989</u>

ORANGE AND ROCKLAND UTILITIES, INC.
Gas Operating Expenses
Regulatory Costs and Amortizations
(000s)

EXHIBIT G-5
SCHEDULE 5
PAGE 1 of 2

TWELVE MONTHS ENDED

Account Group	Per Books 6/30/08	Normalizing Adjustments	Program Changes	Labor Escalation	General Escalation	Other Escalation	Rate Year 10/31/10
Production & Purchases							
Operation	150	0	150	0	0	0	300
Maintenance	0			0	0	0	0
Joint Expense	0			0	0	0	0
Total	<u>150</u>	<u>0</u>	<u>150</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>300</u>
Transmission							
Operation	0			0	0	0	0
Maintenance	0			0	0	0	0
Joint Expense	0			0	0	0	0
Total	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>
Distribution							
Operation	0	0	0	0	0	0	0
Maintenance	0			0	0	0	0
Joint Expense	0			0	0	0	0
Total	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>
Customer Accounts	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>
Customer Service	<u>741</u>	<u>(166)</u>	<u>(125)</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>450</u>
Sales Promotion	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>
Administrative & General							
Operation	208	10	0	0	12	0	229
Maintenance	0			0	0	0	0
Joint Expense	0			0	0	0	0
Total	<u>208</u>	<u>10</u>	<u>0</u>	<u>0</u>	<u>12</u>	<u>0</u>	<u>229</u>
Total Gas Operating Expenses	<u>1,099</u>	<u>(156)</u>	<u>25</u>	<u>0</u>	<u>12</u>	<u>0</u>	<u>979</u>

ORANGE AND ROCKLAND UTILITIES, INC.
Gas Operating Expenses
Regulatory Costs and Amortizations
(\$000s)

EXHIBIT G-5
SCHEDULE 5
PAGE 2 of 2

TWELVE MONTHS ENDED								
<u>O&R Gas Expense</u>	<u>Account</u>	<u>Per Books 6/30/08</u>	<u>Normalizing Adjustments</u>	<u>Program Changes</u>	<u>Labor Escalation</u>	<u>General Escalation</u>	<u>Other Escalation</u>	<u>Rate Year 10/31/10</u>
Research and Development (188102)	930000	208	10	0	0	12	0	229
Amortization of Prior Conservation Fund (254435)	910500	(68)	68	0	0	0	0	0
Amortization of Gas Mains	887000 / 892000	150	0	150	0	0	0	300
Vectorization (182452)	880000	0	0	0	0	0	0	0
Outreach & Education – Current	254440	300	(200)	0	0	0	0	100
Outreach & Education – Passback funds not used	254440	0	0	(150)	0	0	0	(150)
Low Income Programs - Current	254435	475	0	25	0	0	0	500
Low Income Programs - Prior Period	254435	34	(34)	0	0	0	0	0
Total		<u>1,099</u>	<u>(156)</u>	<u>25</u>	<u>0</u>	<u>12</u>	<u>0</u>	<u>979</u>

ORANGE AND ROCKLAND UTILITIES, INC.
Gas Operating Expenses
Pension and OPEBS
(\$000s)

EXHIBIT G-5
SCHEDULE 6
PAGE 1 of 2

TWELVE MONTHS ENDED

Account Group	Per Books 6/30/08	Normalizing Adjustments	Program Changes	Labor Escalation	General Escalation	Other Escalation	Rate Year 10/31/10
Production & Purchases							
Operation	0			0	0	0	0
Maintenance	0			0	0	0	0
Joint Expense	0			0	0	0	0
Total	0	0	0	0	0	0	0
Transmission							
Operation	0			0	0	0	0
Maintenance	0			0	0	0	0
Joint Expense	0			0	0	0	0
Total	0	0	0	0	0	0	0
Distribution							
Operation	0			0	0	0	0
Maintenance	0			0	0	0	0
Joint Expense	0			0	0	0	0
Total	0	0	0	0	0	0	0
Customer Accounts	0	0	0	0	0	0	0
Customer Service	0	0	0	0	0	0	0
Sales Promotion	0	0	0	0	0	0	0
Administrative & General							
Operation	11,970	(999)	82	57	0	0	11,111
Maintenance	0			0	0	0	0
Joint Expense	0			0	0	0	0
Total	11,970	(999)	82	57	0	0	11,111
Total Gas Operating Expenses	11,970	(999)	82	57	0	0	11,111

ORANGE AND ROCKLAND UTILITIES, INC.
Gas Operating Expenses
Pension and OPEBS
(000s)

EXHIBIT G-5
SCHEDULE 6
PAGE 2 of 2

TWELVE MONTHS ENDED

ITEM	Per Books 6/30/08	Normalizing Adjustments	Program Changes	Labor Escalation	General Escalation	Other Escalation	Rate Year 10/31/10
Pension Costs -- Qualified Plan	5,317	0	533	0	0	0	5,850
-- Non-Qualified Plan	733	0	(1)	0	0	0	732
Rate Case Accounting - Pensions	1,970	(205)	(531)	0	0	0	1,234
Amortization of Pension Interest	0	(300)	150	0	0	0	(150)
401K Contributions	490	0	0	57	0	0	547
Total Pension Costs	8,510	(505)	151	57	0	0	8,214
OPEB Costs	2,101	0	266	0	0	0	2,367
Rate Case Accounting - OPEBs	827	0	126	0	0	0	953
Medicare Part D (Deferral / Amort.)	532	(494)	(461)	0	0	0	(423)
Total Post Employment Benefits Other Than Pension	3,460	(494)	(69)	0	0	0	2,897
Total	11,970	(999)	82	57	0	0	11,111

ORANGE AND ROCKLAND UTILITIES, INC.
Gas Operating Expenses
Uncollectible Costs
(\$000s)

EXHIBIT G-5
SCHEDULE 7
PAGE 1 of 2

TWELVE MONTHS ENDED

Account Group	Per Books 6/30/08	Normalizing Adjustments	Program Changes	Labor Escalation	General Escalation	Other Escalation	Rate Year 10/31/10
Production & Purchases							
Operation	0			0	0	0	0
Maintenance	0			0	0	0	0
Joint Expense	0			0	0	0	0
Total	0	0	0	0	0	0	0
Transmission							
Operation	0			0	0	0	0
Maintenance	0			0	0	0	0
Joint Expense	0			0	0	0	0
Total	0	0	0	0	0	0	0
Distribution							
Operation	0			0	0	0	0
Maintenance	0			0	0	0	0
Joint Expense	0			0	0	0	0
Total	0	0	0	0	0	0	0
Customer Accounts	1,271	(26)	(60)	0	0	0	1,185
Customer Service	0	0	0	0	0	0	0
Sales Promotion	0	0	0	0	0	0	0
Administrative & General							
Operation	0			0	0	0	0
Maintenance	0			0	0	0	0
Joint Expense	0			0	0	0	0
Total	0	0	0	0	0	0	0
Total Gas Operating Expenses	1,271	(26)	(60)	0	0	0	1,185

ORANGE AND ROCKLAND UTILITIES, INC.
Gas Operating Expenses
Uncollectible Costs
(\$000s)

EXHIBIT G-5
SCHEDULE 7
PAGE 2 of 2

TWELVE MONTHS ENDED

	Per Books 6/30/08	Normalizing Adjustments	Program Changes	Rate Year As Adjusted	Labor Escalation	General Escalation	Other Escalation	Rate Year 10/31/10
Customer Uncollectibles	1,192	(9)	(60)	1,113	0	0	0	1,113
Sundry Uncollectibles	89	(17)	0	72	0	0	0	72
Uncollectible Account Expense	<u>1,271</u>	<u>(26)</u>	<u>(60)</u>	<u>1,185</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>1,185</u>
Net Uncollectible Write-Offs) (12 Months Ending October	\$ 3,226							
Billed Sales to Customers (E&G)	\$ 684,047							
Percent	0.47%							

ORANGE AND ROCKLAND UTILITIES, INC.
Gas Operating Expenses
MGP Sites & Environmental Costs
(\$000s)

EXHIBIT G-5
SCHEDULE 8
PAGE 1 of 2

TWELVE MONTHS ENDED

Account Group	Per Books 6/30/08	Normalizing Adjustments	Program Changes	Labor Escalation	General Escalation	Other Escalation	Rate Year 10/31/10
Production & Purchases							
Operation	0			0	0	0	0
Maintenance	0			0	0	0	0
Joint Expense	0			0	0	0	0
Total	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>
Transmission							
Operation	0			0	0	0	0
Maintenance	0			0	0	0	0
Joint Expense	0			0	0	0	0
Total	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>
Distribution							
Operation	0		0	0	0	0	0
Maintenance	0			0	0	0	0
Joint Expense	0			0	0	0	0
Total	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>
Customer Accounts	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>
Customer Service	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>
Sales Promotion	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>
Administrative & General							
Operation	1,558	0	154	0	91	0	1,803
Maintenance	0			0	0	0	0
Joint Expense	0			0	0	0	0
Total	<u>1,558</u>	<u>0</u>	<u>154</u>	<u>0</u>	<u>91</u>	<u>0</u>	<u>1,803</u>
Total Gas Operating Expenses	<u>1,558</u>	<u>0</u>	<u>154</u>	<u>0</u>	<u>91</u>	<u>0</u>	<u>1,803</u>

ORANGE AND ROCKLAND UTILITIES, INC.
Gas Operating Expenses
MGP Sites & Environmental Costs
(\$000s)

EXHIBIT G-5
SCHEDULE 8
PAGE 2 of 2

TWELVE MONTHS ENDED

ITEM	Per Books 6/30/08	Normalizing Adjustments	Program Changes	Labor Escalation	General Escalation	Other Escalation	Rate Year 10/31/10
Amortization of Site Investigation and Remediation Costs							
MGP Sites	1,558	0	154	0	91	0	1,803
Total	<u>1,558</u>	<u>0</u>	<u>154</u>	<u>0</u>	<u>91</u>	<u>0</u>	<u>1,803</u>

ORANGE AND ROCKLAND UTILITIES, INC.
Gas Operating Expenses
Gas Department Programs
(\$000s)

EXHIBIT G-5
SCHEDULE 9
PAGE 1 of 2

TWELVE MONTHS ENDED

Account Group	Per Books 6/30/08	Normalizing Adjustments	Program Changes	Labor Escalation	General Escalation	Other Escalation	Rate Year 10/31/10
Production & Purchases							
Operation	15	0	35	0	3	0	53
Maintenance	0	0	0	0	0	0	0
Joint Expense	0	0	0	0	0	0	0
Total	15	0	35	0	3	0	53
Transmission							
Operation	0	0	0	0	0	0	0
Maintenance	0	0	0	0	0	0	0
Joint Expense	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0
Distribution							
Operation	239	0	896	0	34	0	1,169
Maintenance	0	0	65	0	3	0	68
Joint Expense	0	0	0	0	0	0	0
Total	239	0	961	0	37	0	1,237
Customer Accounts	0	0	0	0	0	0	0
Customer Service	0	0	200	0	11	0	211
Sales Promotion	0	0	0	0	0	0	0
Administrative & General							
Operation	0	0	0	0	0	0	0
Maintenance	0	0	0	0	0	0	0
Joint Expense	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0
Total Gas Operating Expenses	254	0	1,196	0	50	0	1,500

ORANGE AND ROCKLAND UTILITIES, INC.
Gas Operating Expenses
Gas Department Programs
(\$000s)

EXHIBIT G-5
SCHEDULE 9
PAGE 2 of 2

TWELVE MONTHS ENDED

ITEM	Per Books 6/30/08	Normalizing Adjustments	Program Changes	Labor Escalation	General Escalation	Other Escalation	Rate Year 10/31/10
Thruway Bridge Crossing Maintenance	0	0	210	0	11	0	221
System Contingencies	0	0	500	0	0	0	500
Locating Expense	239	0	111	0	19	0	369
Distribution Integrity Mgmt Plan	0	0	65	0	3	0	68
Odorizer	15	0	35	0	3	0	53
Gas Rebate Program	0	0	200	0	11	0	211
Additional Vehicle Expense (5 Trucks)	0	0	75	0	4	0	79
Total	<u>254</u>	<u>0</u>	<u>1,196</u>	<u>0</u>	<u>50</u>	<u>0</u>	<u>1,500</u>

ORANGE AND ROCKLAND UTILITIES, INC.
Gas Operating Expenses
Regulatory Commission Expense
(\$000s)

EXHIBIT G-5
SCHEDULE 10
PAGE 1 of 2

TWELVE MONTHS ENDED

Account Group	Per Books 6/30/08	Normalizing Adjustments	Program Changes	Labor Escalation	General Escalation	Other Escalation	Rate Year 10/31/10
Production & Purchases							
Operation	0			0	0	0	0
Maintenance	0			0	0	0	0
Joint Expense	0			0	0	0	0
Total	0	0	0	0	0	0	0
Transmission							
Operation	0			0	0	0	0
Maintenance	0			0	0	0	0
Joint Expense	0			0	0	0	0
Total	0	0	0	0	0	0	0
Distribution							
Operation	0			0	0	0	0
Maintenance	0			0	0	0	0
Joint Expense	0			0	0	0	0
Total	0	0	0	0	0	0	0
Customer Accounts	0	0	0	0	0	0	0
Customer Service	0	0	0	0	0	0	0
Sales Promotion	0	0	0	0	0	0	0
Administrative & General							
Operation	639	0	65	0	37	0	741
Maintenance	0	0	0	0	0	0	0
Joint Expense	0	0	0	0	0	0	0
Total	639	0	65	0	37	0	741
Total Gas Operating Expense	639	0	65	0	37	0	741

ORANGE AND ROCKLAND UTILITIES, INC.
Gas Operating Expenses
Regulatory Commission Expense
(\$000s)

TWELVE MONTHS ENDED

<u>O&R Gas Expense</u>	<u>Per Books 6/30/08</u>	<u>Normalizing Adjustments</u>	<u>Program Changes</u>	<u>Labor Escalation</u>	<u>General Escalation</u>	<u>Other Escalation</u>	<u>Rate Year 10/31/10</u>
NYSPC Assessment	622	0	65	0	36	0	723
Amortization of Rate Case Costs	17	0	0	0	1	0	18
Total	<u>639</u>	<u>0</u>	<u>65</u>	<u>0</u>	<u>37</u>	<u>0</u>	<u>741</u>

ORANGE AND ROCKLAND UTILITIES, INC.
Gas Operating Expenses
Other O&M Costs
(\$000s)

EXHIBIT G-5
SCHEDULE 11
PAGE 1 of 2

TWELVE MONTHS ENDED							
Account Group	Per Books 6/30/08	Normalizing Adjustments	Program Changes	Labor Escalation	General Escalation	Other Escalation	Rate Year 10/31/10
Production & Purchases							
Operation	37	(7)	0	0	2	0	31
Maintenance	11	0	0	0	1	0	11
Joint Expense	0	0	0	0	0	0	0
Total	47	(7)	0	0	2	0	42
Transmission							
Operation	0	0	0	0	0	0	0
Maintenance	0	0	0	0	0	0	0
Joint Expense	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0
Distribution							
Operation	2,844	7	0	0	148	0	3,000
Maintenance	1,635	0	0	0	85	0	1,720
Joint Expense	0	0	0	0	0	0	0
Total	4,479	7	0	0	234	0	4,720
Customer Accounts	1,766	0	0	0	92	0	1,858
Customer Service	501	0	0	0	26	0	527
Sales Promotion	0	9	0	0	0	0	9
Administrative & General							
Operation	796	271	0	0	56	0	1,123
Maintenance	93	0	0	0	5	0	98
Joint Expense	0	0	0	0	0	0	0
Total	890	271	0	0	61	0	1,222
Total Gas Operating Expenses	7,683	280	0	0	415	0	8,378

ORANGE AND ROCKLAND UTILITIES, INC.
Gas Operating Expenses
Other O&M Costs
(\$000s)

EXHIBIT G-5
SCHEDULE 11
PAGE 2 of 2

TWELVE MONTHS ENDED							
ITEM	Per Books 6/30/08	Normalizing Adjustments	Program Changes	Labor Escalation	General Escalation	Other Escalation	Rate Year 10/31/10
<u>O&R Gas Expense</u>							
Advertising	* 3	138	0	0	7	0	148
Building Services	* 575	0	0	0	30	0	605
Information Technology Solutions	* 851	0	0	0	44	0	895
Legal & Other Professional Services	* 314	0	0	0	16	0	330
Rents	* 36	0	0	0	2	0	38
Telecommunications	* 283	0	0	0	15	0	297
Transportation	* 1,445	0	0	0	75	0	1,520
Materials and Supplies	* 465	0	0	0	24	0	489
Corporate Fiscal	* 193	142	0	0	17	0	352
	<u>4,165</u>	<u>280</u>	<u>0</u>	<u>0</u>	<u>232</u>	<u>0</u>	<u>4,676</u>
Other Expense - Gas Only	* <u>3,519</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>183</u>	<u>0</u>	<u>3,702</u>
	<u>7,683</u>	<u>280</u>	<u>0</u>	<u>0</u>	<u>415</u>	<u>0</u>	<u>8,378</u>

* Elements Subject to Inflation
General Escalation Factor

ORANGE AND ROCKLAND UTILITIES, INC.

INDEX OF SCHEDULES

Forecasted Construction Expenditures /
Plant Additions for the Twelve Months Ended
October 31, 2010, 2011 and 2012

<u>SCHEDULE</u>	<u>TITLE OF SCHEDULE</u>	<u>WITNESS</u>
1	Forecasted Gas Construction Expenditures November 1, 2009 through October 31, 2012	R. Diloreto
2	Forecasted Gas Plant Additions November 1, 2009 through October 31, 2012	R. Diloreto
3	Forecasted Common Construction Expenditures November 1, 2009 through October 31, 2012	Accounting Panel
4	Forecasted Common Plant Additions November 1, 2009 through October 31, 2012	Accounting Panel

Orange and Rockland Utilities, Inc.
Forecasted Gas Construction Expenditures
November 2009 thru October 2012

<u>Budget Number</u>	<u>Project Description</u>	<u>In Service Date</u>	<u>12 Months Ended 10/31/2010</u>	<u>12 Months Ended 10/31/2011</u>	<u>12 Months Ended 10/31/2012</u>
<u>Gas Plant</u>					
G173EG	Gas Expansion - Middletown to Bloomingburg	Various	\$ 1,459.0	\$ 1,750.5	\$ 1,750.5
	All Other Gas Blankets	Various	27,313.2	29,455.6	31,694.7
G177EL	Rt 17A to Maple St - Village of Florida	Nov-09	705.4	-	-
G440EX	Rt 94 Chester-Washingtonville 12" Redund	Nov-09	518.4	-	-
G436EB	Redundancy Craigvl Rd to Rt 94 Chester 2	Sep-10	2,242.5	-	-
G134EX	Middletown Dist Redund Genung-Golf Links	Oct-10	1,516.2	-	-
G429EC	Rate Case Redundancy-Lower Rd & Reg Sta	Oct-10	2,224.7	-	-
G146EX	Relocate Chester Regulator Station	Oct-10	433.7	-	-
G138EX	Upgrade Denton Hill Regulator Station	Oct-10	487.9	-	-
G150EX	Upgrade Hoover Lane Regulator Station	Oct-10	329.6	-	-
G441EX	Westtown/Warwick Loop - Rt 6 Downgrade	Oct-10	246.5	-	-
G169EB	2010 Distribution Reinforcement	Nov-10	567.7	81.1	-
G121EX	Upgrade Middletown Plant Yrd Reg Station	Nov-10	266.4	15.8	-
G442EX	Bowline Metering	Dec-10	195.0	92.3	-
G636EF	Gas Inspection Mgmt System Ph 6	Dec-10	403.0	80.6	-
G636EG	Gas Inspection Mgmt System Ph 7	Dec-11	-	406.0	81.2
G636EH	Gas Inspection Mgmt System Ph 8	Dec-13	-	-	403.0
G431ED	Gas Mobile Dispatching System Ph 6	Dec-10	606.0	121.2	-
G431EE	Gas Mobile Dispatching System Ph 7	Dec-11	-	609.0	121.8
G431EF	Gas Mobile Dispatching System Ph 8	Dec-12	-	-	607.0
G147EX	Samsondale District Regulator Station	Dec-10	276.7	166.8	-
G132EX	Middletown Reg Station/PP Tie 6000' 12"	Aug-11	-	1,157.7	-
G136EX	New Middletown Transmission & Reg St Ph1	Oct-11	-	3,864.6	-
G131EX	Hillburn to Sloatsburg Redundancy	Nov-11	-	1,254.0	209.0
G118EX	Upgrade Cedar Flats Rd Regulator Station	Nov-11	-	339.3	51.4
G443EX	Upgrade Eckerson Lane Regulator Station	Nov-11	-	339.6	51.2
G179KG	Gas Load Research	Dec-11	110.6	80.6	11.8
G108EX	Suffern Gate Station Heater	Dec-11	-	167.8	45.0
G143EX	Upgrade Stony Point Flow Controls	Dec-11	-	164.5	61.7
G157EX	Riverside Ave Tilcon to Cul-de-sac	Jul-12	-	-	541.6
G158EX	Rt 9W Rt 304 to Riverside Ave Cul-de-sac	Jul-12	-	-	446.9
G135EX	New City - Congers Rd Causeway	Aug-12	-	-	864.8
G136EA	New Middletown Transmission & Reg St Ph2	Oct-12	-	-	3,313.2
G140EX	Upgrade West Main St Reg Station	Oct-12	-	-	538.4
All Other Projects			428.3	391.5	483.4
Total Gas Distribution			\$ 40,330.8	\$ 40,538.5	\$ 41,276.6

Orange and Rockland Utilities, Inc.
Forecasted Gas Construction Additions
November 2009 thru October 2012

<u>Budget Number</u>	<u>Project Description</u>	<u>In Service Date</u>	<u>12 Months Ended 10/31/2010</u>	<u>12 Months Ended 10/31/2011</u>	<u>12 Months Ended 10/31/2012</u>
<u>Gas Plant</u>					
G173EG	Gas Expansion - Middletown to Bloomingburg	Various	\$ 1,459.0	\$ 1,750.5	\$ 1,750.5
	All Other Gas Blankets	Various	25,897.6	28,096.9	30,403.0
G177EL	Rt 17A to Maple St - Village of Florida	Nov-09	5,016.2	-	-
G440EX	Rt 94 Chester-Washingtonville 12" Redund	Nov-09	3,686.4	-	-
G636EE	Gas Inspection Mgmt System Ph 5	Dec-09	201.0	-	-
G636EF	Gas Inspection Mgmt System Ph 6	Dec-10	-	496.9	-
G636EG	Gas Inspection Mgmt System Ph 7	Dec-11	-	-	500.6
G431EC	Gas Mobile Dispatching System Ph 5	Dec-09	355.1	-	-
G431ED	Gas Mobile Dispatching System Ph 6	Dec-10	-	747.1	-
G431EE	Gas Mobile Dispatching System Ph 7	Dec-11	-	-	750.8
G436EB	Redundancy Craigvl Rd to Rt 94 Chester 2	Sep-10	2,267.9	-	-
G134EX	Middletown Dist Redund Genung-Golf Links	Oct-10	1,536.8	-	-
G429EC	Rate Case Reinforcement-Lower Rd & Reg Sta	Oct-10	6,616.3	-	-
G146EX	Relocate Chester Regulator Station	Oct-10	935.9	-	-
G138EX	Upgrade Denton Hill Regulator Station	Oct-10	492.7	-	-
G150EX	Upgrade Hoover Lane Regulator Station	Oct-10	332.7	-	-
G441EX	Westtown/Warwick Loop - Rt 6 Downgrade	Oct-10	247.1	-	-
G169EB	2010 Distribution Reinforcement	Nov-10	-	660.6	-
G443EX	Upgrade Eckerson Lane Regulator Station	Nov-10	-	-	396.6
G121EX	Upgrade Middletown Plant Yrd Reg Station	Nov-10	-	285.5	-
G442EX	Bowline Metering	Dec-10	-	290.7	-
G147EX	Samsondale District Regulator Station	Dec-10	-	449.0	-
G132EX	Middletown Reg Station/PP Tie 6000' 12"	Aug-11	-	1,165.5	-
G135EX	New City - Congers Rd Causeway	Sep-11	-	-	868.7
G136EX	New Middletown Transmission & Reg St Ph1	Oct-11	-	3,917.1	-
G131EX	Hillburn to Sloatsburg Redundancy	Nov-11	-	-	1,486.2
G118EX	Upgrade Cedar Flats Rd Regulator Station	Nov-11	-	-	397.4
G108EX	Suffern Gate Station Heater	Dec-11	-	-	216.1
G143EX	Upgrade Stony Point Flow Controls	Dec-11	-	-	229.3
G140EX	Upgrade West Main St Reg Station	Dec-11	-	-	544.3
G157EX	Riverside Ave Tilcon to Cul-de-sac	Jul-12	-	-	544.0
G158EX	Rt 9W Rt 304 to Riverside Ave Cul-de-sac	Jul-12	-	-	448.9
G136EA	New Middletown Transmission & Reg St Ph2	Oct-12	-	-	3,358.2
All Other Projects			309.9	367.5	319.5
Total Gas Distribution			<u>\$ 49,354.5</u>	<u>\$ 38,227.4</u>	<u>\$ 42,214.2</u>

Orange and Rockland Utilities, Inc.
Forecasted Common Construction Expenditures
November 2009 thru October 2012

<u>Budget Number</u>	<u>Project Description</u>	<u>In Service Date</u>	<u>12 Months Ended 10/31/2010</u>	<u>12 Months Ended 10/31/2011</u>	<u>12 Months Ended 10/31/2012</u>
<u>Common Plant</u>					
	Common Plant Blankets		6,410.6	5,927.6	5,640.4
P500NX	SVOC HVAC Automated Remote Control	Nov-09	154.0	-	-
P502NX	Middletown Upper Roof	Nov-09	154.0	-	-
P213MF	Mainframe Upgrade Printer Upgrade 2010	Jul-10	333.8	-	-
P231NX	Middletown Employee Lot Paving	Jul-10	174.3	-	-
P300MX	ECC/DCC Turret System Replacement	Oct-10	214.8	-	-
P324WX	FORD Wireless Phase II	Oct-10	1,061.4	-	-
P164MM	Radio System Upgrade Part 1	Dec-10	226.4	50.3	-
P281NX	BG Truck Shed Sprinkler System	Sep-11	-	216.0	-
P283NX	SVDC Generator	Nov-11	-	179.9	195.4
P164MN	Radio System Upgrade Part 2	Dec-11	-	503.8	25.8
P251MX	Telephone System Replacement	Dec-11	90.4	201.6	-
P283NA	West Nyack and Middletown Generators	Dec-11	-	1,028.4	259.6
P307WX	Process Management Software (CALM)	Dec-11	193.6	49.8	-
P213MA	Mainframe Upgrade 2010	Mar-12	552.0	-	604.7
P213MC	Mainframe Upgrade DASD Storage 2010	Mar-12	183.4	-	190.4
P293NX	HVAC Units #5, #7, #10	May-12	-	-	154.1
P279NX	BG Stores Yard and Employee Lot Paving	Aug-12	-	-	154.1
P292NX	SV Garage Area & Lot C Paving	Aug-12	-	-	267.2
P313VX	Financial General Ledger / Supply Chain	Aug-12	3,031.0	1,680.4	721.9
P291NA	Middletown Paving - Stores Yard	Sep-12	-	-	200.4
P164MP	Radio System Upgrade Part 3	Dec-12	-	-	448.5
P325WX	Itron P4 Handheld Replacement	After 2013	-	-	1,049.3
All Other (Projects < \$150.0K)			1,027.3	598.6	120.8
			<u>\$ 13,807.0</u>	<u>\$ 10,436.4</u>	<u>\$ 10,032.6</u>

Orange and Rockland Utilities, Inc.
Forecasted Common Construction Additions
November 2009 thru October 2012

<u>Budget Number</u>	<u>Project Description</u>	<u>In Service Date</u>	<u>12 Months Ended 10/31/2010</u>	<u>12 Months Ended 10/31/2011</u>	<u>12 Months Ended 10/31/2012</u>
<u>Common Plant</u>					
	Common Plant Blankets		8,255.2	6,076.0	7,871.4
P502NX	Middletown Upper Roof	Nov-09	206.0	-	-
P500NX	SVOC HVAC Automated Remote Control	Nov-09	309.4	-	-
P307WX	Process Management Software (CALM)	Dec-09	-	-	1,278.5
P312KX	Power Plant - Budget Development System	Mar-10	206.2	-	-
P294NX	Telecommunications HVAC Units	Apr-10	157.1	-	-
P231NX	Middletown Employee Lot Paving	Jul-10	174.7	-	-
P300MX	ECC/DCC Turret System Replacement	Oct-10	218.2	-	-
P302MX	Replacement of Obsolete Technologies	Dec-10	90.4	115.7	110.8
P281NX	BG Truck Shed Sprinkler System	Sep-11	-	216.5	-
P283NX	SVDC Generator	Nov-11	-	-	378.6
P290NT	Modular Furniture Replacement Bkt - NY	Dec-11	513.6	515.4	-
P283NA	West Nyack and Middletown Generators	Dec-11	-	-	1,303.0
P293NX	HVAC Units #5, #7, #10	May-12	-	-	154.4
P279NX	BG Stores Yard and Employee Lot Paving	Jul-12	-	-	154.4
P292NX	SV Garage Area & Lot C Paving	Aug-12	-	-	267.8
P313VX	Financial General Ledger / Supply Chain	Aug-12	-	-	8,022.1
P291NA	Middletown Paving - Stores Yard	Sep-12	-	-	200.9
All Other (Projects < \$150.0K)			989.8	576.7	97.9
			<u>\$ 11,120.5</u>	<u>\$ 7,500.2</u>	<u>\$ 19,839.9</u>

ORANGE AND ROCKLAND UTILITIES, INC.

INDEX OF SCHEDULES

Multi-Year Forecast-GAS

<u>SCHEDULE</u>	<u>TITLE OF SCHEDULE</u>	<u>WITNESS</u>
1	Gas Income Statement	Accounting Panel
2	Capital Structure and Returns	"
3	Sales Delivery and Net Revenue Margins	"
4	Other Operating Revenues	"
5	O&M Expenses	"
6	Depreciation Calculation - Gas	"
7	Taxes Other than Income Taxes - Gas	"
8	State Income Tax Expense -Gas	"
9	Federal Income Tax Expense - Gas	"
10	Rate Base	"
11	Interest Synchronization	"

ORANGE AND ROCKLAND UTILITIES, INC.
MULTI-YEAR RATE PLAN
(\$ in millions)

	Exhibit G-4 Schedule	Rate Year Ending October 31,		
		2007	2008	2009
Base Rate Increase - RY1	Sch 3	\$ 17.8		
Less: Non-Firm Revenue Imputation		(1.1)		
: RY3 Revenue Surcharge		(4.5)		
Customer Bill Impact		<u>12.2</u>		
Operating Revenues				
Sales Revenue (Net of Fuel & Governmental Surcharges)	Sch3	\$ 0.2	\$ 1.4	
Subtotal (1)		<u>0.2</u>	<u>1.4</u>	
Operating Expenses				
Operation & Maintenance Expense (excl. fuel)				
- Labor & General Escalations	Sch 5	1.4	1.0	
- Gas Operation -- Programs	Sch 5	0.7	-	
- Pension and OPEBs	Sch 5	(1.1)	(0.6)	
- Environmental	Sch 5	0.6	0.4	
Depreciation & Amortization	Sch 6	1.0	0.7	
Property and Other Taxes	Sch 7	0.6	0.6	
Return on Rate Base	Sch 9	3.3	2.6	
Income Tax Expense (Flow Thru Items)	Sch 8	0.6	0.6	
Subtotal (2)		<u>7.1</u>	<u>5.3</u>	
Increase in Net Operating Expenses (2) - (1)		<u>6.9</u>	<u>3.9</u>	
Continue Existing Annual True Up Mechanisms For				
Property Tax Expense		-	-	-
Pensions / OPEBs (Policy Statement)		-	-	-
Environmental Remediation (MGP)		-	-	-
Research & Development Costs (1978 Technical Release)		-	-	-
Low Income Program		-	-	-
New True Ups For				
Hyper Inflation		-	-	-
Interest Rates / Pollution Control Bonds		-	-	-
Net Rate Change		<u>\$ 12.2</u>	<u>\$ 6.9</u>	<u>\$ 3.9</u>
Percent Increase Over Base Year		<u>2.8%</u>	<u>1.6%</u>	<u>0.9%</u>

Orange & Rockland Utilities, Inc.
Gas Department
Operating Income, Rate Base & Rate of Return
(\$000's)

TWELVE MONTHS ENDING OCTOBER 31, 2011

	2010			Rate Year	Proposed	Rate Year
	Exhibit G-4 and G-5	Sched.	Adjustments	As Adjusted	Rate Change	As Adjusted For Proposed Rate Increase
Operating Revenues						
Sales & Deliveries to Public	\$254,609	[3]	(\$3,461)	\$251,148	\$6,922	\$258,070
Sales For Resale	2,048	[3]	135	2,183	-	2,183
Other Operating Revenues	3,248	[4]	(20)	3,228	38	3,266
Total Operating Revenues	259,906		(3,346)	256,559	6,960	263,519
OPERATING EXPENSES						
Purchased Power Costs	138,567	[5]	839	139,406	-	139,406
Deferred Purchased Power	5,761	[5]	(4,434)	1,327	-	1,327
Other Operations & Maintenance	56,411	[5]	1,624	58,035	33	58,068
Total Operation & Maintenance Expenses	200,739		(1,971)	198,768	33	198,801
Depreciation - Existing rates	11,153	[6]	982	12,135	-	12,135
- Proposed rates	(503)	[6]	49	(454)	-	(454)
Amortization of Ltd Term Plant	1,508	[6]	-	1,508	-	1,508
Taxes Other Than Income Taxes	13,477	[7]	584	14,061	71	14,132
Total Operating Revenue Deductions	226,374		(356)	226,018	104	226,122
Operating Income Before Income Taxes	33,532		(2,990)	30,541	6,856	37,397
Income Taxes						
New York State Income Taxes	1,586	[8]	(323)	1,263	487	1,750
Federal Income Tax	4,006	[9]	(13,073)	(9,067)	2,230	(6,837)
Deferred Federal Income Taxes	3,126	[9]	11,637	14,763	-	14,763
Total Income Taxes	8,718		(13,396)	6,959	2,717	9,676
Operating Income After Income Taxes	\$24,814		\$10,406	\$23,582	\$4,139	\$27,721
Rate Base	273,943		24,382	298,326		298,326
EB-Cap Adjustment to Rate Base	(12,183)		-	(12,183)		(12,183)
Total Rate Base	\$261,760	[10]	\$24,382	\$286,143		\$286,143
Overall Rate of Return	9.48%			8.24%		9.69%
Return on Equity	11.60%					11.60%

TWELVE MONTHS ENDING JUNE 30, 2012

	Adjusted	Sched.	Adjustments	#VALUE!	Changes	Adjusted
Operating Revenues						
Sales Revenues	\$258,070	[3]	\$6,591	\$264,661	\$3,853	\$268,514
Sales For Resale	2,183	[3]	167	2,350	-	2,350
Other Operating Revenues	3,266	[4]	11	3,277	21	3,298
Total Operating Revenues	263,519		6,769	270,288	3,874	274,162
Operating Revenue Deductions						
Purchased Power Costs	139,406		5,675	145,081	-	145,081
Deferred Purchased Power	1,327		(433)	894	-	894
Other Operations & Maintenance (excl. Pensions)	58,068	[5]	814	58,882	18	58,900
Pension / OPEBs	198,801	[5]	6,056	204,857	18	204,875
Depreciation - Existing rates	12,135	[6]	724	12,859	-	12,859
- Proposed rates	(454)		-	(454)	-	(454)
Amortization of Ltd Term Plant	1,508		-	1,508	-	1,508
Taxes Other Than Income Taxes	14,132	[7]	626	14,758	39	14,797
Total Operating Revenue Deductions	226,122		7,406	233,528	57	233,585
Operating Income Before Income Taxes	37,397		(637)	36,760	3,817	40,577
Income Taxes						
New York State Income Taxes	1,750	[8]	(121)	1,629	271	1,900
Federal Income Tax	(6,837)		4,297	(2,541)	1,241	(1,300)
Deferred Federal Income Taxes	14,763	[9]	(4,653)	10,110	-	10,110
Total Income Taxes	9,676		(477)	9,198	1,512	10,710
Operating Income After Income Taxes	\$27,721		(\$160)	\$27,562	\$2,305	\$29,867
Rate Base	298,326		19,626	317,952		317,952
EB-Cap Adjustment to Rate Base	(12,183)		-	(12,183)		(12,183)
Total Rate Base	\$286,143	[10]	\$19,626	\$305,769		\$305,769
Overall Rate of Return	9.69%			9.01%		9.77%
Return on Equity	11.60%					11.60%

Orange & Rockland Utilities, Inc.
Gas Rate Case
(000's)

Levelized Rate Increase

Other Customer Provided Capital Rate = 5.5%

Rate Increase	Twelve Months Ending			Cumulative Total
	October 31, 2010	October 31, 2010	October 31, 2010	
R.Y. - 1	\$17,773	\$17,773	\$17,773	\$53,319
R.Y. - 2		6,922	6,922	13,844
R.Y. - 3			3,853	3,853
Total	<u>\$ 17,773</u>	<u>\$ 24,695</u>	<u>\$ 28,548</u>	<u>\$ 71,016</u>
Annual rate increase w/o interest				
R.Y. - 1	\$ 11,836	\$ 11,836	\$ 11,836	\$ 35,508
R.Y. - 2		11,836	11,836	23,672
R.Y. - 3			11,836	11,836
Total	<u>\$ 11,836</u>	<u>\$ 23,672</u>	<u>\$ 35,508</u>	<u>\$ 71,016</u>
Interest	<u>\$ 99</u>	<u>\$ 214</u>	<u>\$ 116</u>	<u>\$ 429</u>
Annual rate increase w/ interest				
R.Y. - 1	\$ 11,907	\$ 11,907	\$ 11,907	\$ 35,722
R.Y. - 2		11,907	11,907	23,815
R.Y. - 3			11,907	11,907
Total	<u>\$ 11,907</u>	<u>\$ 23,815</u>	<u>\$ 35,722</u>	<u>\$ 71,445</u>

Orange & Rockland Utilities, Inc.
Gas Department
Revenue Calculation
(\$000's)

	Twelve Months Ended October 31,	
	2011	2012
Rate Base (Exhibit G-6, Schedule 10)	\$286,143	\$305,769
Rate of Return (Exhibit-7, Schedule 1)	9.69%	9.77%
Required Return	27,723	29,867
Income Available (Exhibit G-6, Schedule 1)	23,582	27,562
Deficiency	4,140	2,305
Retention Factor	59.8%	59.8%
Additional Revenue Requirement	\$6,922	\$3,853

	<u>Proof</u>		
Revenues	100.00%	\$6,922	\$3,853
Less: Revenue Taxes	1.02%	71	39
Late Payment Charges	-0.55%	(38)	(21)
Uncollectibles	0.47%	33	18
	99.06%	6,857	3,817
New York State Income Tax @ 7.1%	7.03%	487	271
Federal Income Tax @ 35%	32.21%	2,230	1,241
Retention Factor	59.82%	\$4,140	\$2,305

ORANGE AND ROCKLAND UTILITIES, INC.
CONSOLIDATED CAPITAL STRUCTURE

TWELVE MONTHS ENDED OCTOBER 31, 2010

	(\$000's) Amount	Calculated %	Adjusted %	COST RATE	WEIGHTED COST
LONG-TERM DEBT	\$ 532,544,622	48.38%	50.61%	7.62%	3.86%
CUSTOMER DEPOSITS	14,586,000	1.33%	1.39%	3.92%	0.05%
COMMON EQUITY	553,564,200	50.29%	48.00%	11.60%	5.57%
TOTAL CAPITALIZATION	<u>\$ 1,100,694,822</u>	<u>100.00%</u>	<u>100.00%</u>		<u>9.48%</u>

TWELVE MONTHS ENDED OCTOBER 31, 2011

	(\$000's) Amount	Calculated %	Adjusted %	COST RATE	WEIGHTED COST
LONG-TERM DEBT	\$ 607,616,500	49.23%	50.78%	8.02%	4.07%
CUSTOMER DEPOSITS	14,586,000	1.18%	1.22%	3.92%	0.05%
COMMON EQUITY	612,133,200	49.59%	48.00%	11.60%	5.57%
TOTAL CAPITALIZATION	<u>\$ 1,234,335,700</u>	<u>100.00%</u>	<u>100.00%</u>		<u>9.69%</u>

TWELVE MONTHS ENDED OCTOBER 31, 2012

	(\$000's) Amount	Calculated %	Adjusted %	COST RATE	WEIGHTED COST
LONG-TERM DEBT	\$ 650,170,218	47.42%	50.86%	8.17%	4.16%
CUSTOMER DEPOSITS	14,586,000	1.06%	1.14%	3.92%	0.04%
COMMON EQUITY	706,475,200	51.52%	48.00%	11.60%	5.57%
TOTAL CAPITALIZATION	<u>\$ 1,371,231,418</u>	<u>100.00%</u>	<u>100.00%</u>		<u>9.77%</u>

ORANGE AND ROCKLAND UTILITIES, INC.
SALES, DELIVERIES AND NET REVENUE MARGINS
FOR THE TWELVE MONTHS ENDING OCTOBER 31, 2010, 2011 & 2012
(\$000s)

	2,010	2,011	2,012
<u>Firm Revenues</u>			
Delivery Revenues	\$ 85,079	\$ 85,369	\$ 86,731
- Non Competitive	4,806	4,804	4,856
- Competitive	243	243	246
Gas Supply Charge	135,552	137,989	143,035
Revenue Taxes	2,321	2,374	2,493
Total	228,001	230,779	237,361
<u>Interruptible Revenues</u>			
SC 5	7	7	7
SC 8/13	2,217	2,217	2,225
SC 10	372	372	373
Gas Supply Charge	6,193	-	-
Revenue Taxes	46	46	46
Total	8,835	2,596	2,605
<u>Rate Relief</u>			
RY 1 Rate Relief (excl. rev. taxes)	17,590	17,590	17,590
RY 1 Revenue Taxes	183	183	183
RY 2 Rate Relief (excl. rev. taxes)	-	-	6,851
RY 2 Revenue Taxes	-	-	71
Total	17,773	17,773	24,695
<u>Sales For Resale</u>			
Pike Capacity Charges	163	163	163
Gas Supply Costs	1,885	2,020	2,187
	2,048	2,183	2,350
Total Delivery Revenues	256,657	253,331	267,011
<u>Purchased Gas Costs</u>			
Purchased Gas	138,403	139,239	144,910
Deferred Gas Cost	5,761	1,327	894
Total	144,164	140,566	145,804
Total Gas Cost Recoveries			
Firm	135,552	137,989	143,035
Interruptible	6,193	-	-
Sales For Resale	1,885	2,020	2,187
Company Use	534	557	582
	144,164	140,566	145,804
Less: Purchased Gas Costs	(144,164)	(140,566)	(145,804)
Variation	-	-	-
<u>Tax Recovery Revenue</u>			
Firm	2,321	2,374	2,493
Interruptible	46	46	46
Total	2,367	2,420	2,539
Revenues	238,884	235,558	242,316
Purchased Gas Costs	(144,164)	(140,566)	(145,804)
Revenue Taxes	(2,367)	(2,420)	(2,539)
	92,353	92,572	93,973
<u>Sales and Deliveries To Public</u>			
Firm Volumes	19,878,620	19,869,920	20,086,020
Interruptible	5,322,200	5,322,200	5,340,500
Total	25,200,820	25,192,120	25,426,520

ORANGE & ROCKLAND UTILITIES, INC.
ELECTRIC OPERATION AND MAINTENANCE EXPENSES (excl. Purchased Gas Costs)
FOR THE YEARS ENDING OCTOBER 31, 2011 AND OCTOBER 31, 2012
(\$000s)

LINE NO.		12 Months			Escalation for 12 Months			12 Months			Escalation for 12 Months			12 Months	
		Ending June 30, 2010	Payroll Escal. @ 5.9%	Subject to Inflation @ 2.1%	Ending June 30, 2011	Rate Year 2 Adjustments	Ending June 30, 2011	Payroll Escal. @ 4.1%	Subject to Inflation @ 2.1%	Ending June 30, 2012	Ending June 30, 2012	Ending June 30, 2012	Ending June 30, 2012	Ending June 30, 2012	Ending June 30, 2012
1	Purchased Gas Costs	138,403	N	N	-	836	139,239	N	N	5,671	144,910				
2	Other Gas Supply Costs	164	N	Y	3	-	167	N	Y	4	171				
3	Deferred Purchased Gas	5,761	N	N	-	(4,434)	1,327	N	N	(433)	894				
		<u>144,328</u>			<u>3</u>	<u>(3,598)</u>	<u>140,733</u>			<u>5,242</u>	<u>145,975</u>				
4	Direct Labor (Excl. Shared Services)	22,518	Y	N	1,332	(225)	23,625	Y	N	723	24,347				
5	Shared Services	4,123	N	Y	87	-	4,210	N	Y	88	4,299				
6	Employee and Welfare Costs	3,989	N	Y	84	(135)	4,073	N	Y	(82)	3,992				
7	Regulatory Costs and Amortizations:	979	N	Y	21	-	1,000	N	Y	21	1,021				
8	Pensions and OPEBS	11,111	N	N	-	(1,109)	10,002	N	N	(604)	9,398				
9	Uncollectible Accounts	1,269	N	n	-	(16)	1,253	N	n	-	1,253				
10	MGP Sites and West Nyack Environmental Costs	1,803	N	N	-	634	2,437	N	N	390	2,827				
11	Gas Operation Programs	1,500	N	Y	32	725	2,257	N	Y	82	2,339				
12	Regulatory Commission Expenses	741	N	Y	16	-	757	N	Y	16	773				
	<u>Other O&M Costs</u>														
13	Advertising	148	N	Y	3	-	152	N	Y	3	155				
14	Building Services	605	N	Y	13	-	618	N	Y	13	631				
15	Information Technology Services	895	N	Y	19	-	914	N	Y	19	933				
16	Legal & other professional services	330	N	Y	7	-	337	N	Y	7	344				
17	Rents	38	N	Y	1	-	39	N	Y	1	40				
18	Telecommunications	297	N	Y	6	-	303	N	Y	6	310				
19	Transportation	1,520	N	Y	33	-	1,553	N	Y	33	1,585				
20	Materials and Supplies	489	N	Y	10	-	499	N	Y	10	510				
21	Corporate Fiscal	352	N	Y	7	-	359	N	Y	8	367				
22	Other O&M	3,704	N	Y	78	-	3,782	N	Y	79	3,862				
23	Total Other O&M expenses	<u>8,378</u>			<u>178</u>	<u>-</u>	<u>8,556</u>			<u>180</u>	<u>8,736</u>				
	Total O&M Expenses (excl. purchased gas costs)	<u>\$ 56,411</u>			<u>\$ 1,750</u>	<u>\$ (126)</u>	<u>\$ 58,170</u>			<u>\$ 814</u>	<u>\$ 58,985</u>				

ORANGE & ROCKLAND UTILITIES, INC.
GAS PENSION / OPEBs EXPENSE
FOR THE YEARS ENDING OCTOBER 31, 2011 AND OCTOBER 31, 2012
(\$000s)

Gas Expense	12 Months Ending June 30, 2010	Program Changes	12 Months Ending June 30, 2011
FAS 87 Pension Costs - Qualified Plan	\$ 8,141	\$ (1,654)	\$ 6,488
Capitalized / Recovered Costs	(2,291)	465	(1,826)
Subtotal	5,850	(1,188)	4,662
Amort. Of Deferred Pension Costs	1,084	-	1,084
Net Qualified Pension Costs	6,935	(1,188)	5,746
Supplemental Pension Expense	555	(19)	536
TOLI Expenses	177	(6)	171
401K Contributions	547	32	580
Total Pension Expense	8,214	(1,181)	7,033
FAS 106 OPEB Costs	4,372	134	4,506
Pay-As-You-Go	(674)	(21)	(695)
Capitalized / Recovered Costs	(1,332)	(41)	(1,372)
Subtotal	2,366	72	2,439
Amort. Of Transitional Obligation	953	-	953
Amort. Of Deferred OPEB Costs	-	-	-
Net Qualified Pension Costs	3,320	72	3,392
Medicare Part D Tax Benefit - Deferral	-	-	-
- Amortization	(423)	-	(423)
Total OPEB Expense	2,897	72	2,969
Total	11,110	(1,109)	10,002

Gas Expense	12 Months Ending June 30, 2011	Program Changes	12 Months Ending June 30, 2012
FAS 87 Pension Costs - Qualified Plan	6,488	(823)	5,665
Capitalized / Recovered Costs	(1,826)	232	(1,594)
Subtotal	4,662	(591)	4,071
Amort. Of Deferred Pension Costs (5 Yrs)	1,084	-	1,084
Net Qualified Pension Costs	5,746	(591)	5,155
Supplemental Pension Expense	536	(9)	527
TOLI Expenses	171	(3)	168
401K Contributions	580	26	606
Total Pension Expense	7,033	(577)	6,456
FAS 106 OPEB Costs	4,506	(50)	4,456
Pay-As-You-Go	(695)	8	(687)
Capitalized / Recovered Costs	(1,372)	15	(1,357)
Subtotal	2,439	(27)	2,412
OPEB Deferral	-	-	-
Amort. Of Transitional Obligation	953	-	953
Amort. Of Deferred OPEB Costs (5 Yrs)	-	-	-
Net Qualified Pension Costs	3,392	(27)	3,365
Medicare Part D Tax Benefit - Deferral	-	-	-
- Amortization	(423)	-	(423)
Total OPEB Expense	2,969	(27)	2,942
Total	10,002	(604)	9,398

ORANGE & ROCKLAND UTILITIES, INC.
MGP SITES & OTHER ENVIRONMENTAL COSTS (\$,000s)
FOR THE YEARS ENDING OCTOBER 31, 2011 AND OCTOBER 31, 2012

LINE NO.		12 Months Ending October 31, 2010	Subject to Inflation @ 2.1%	Escalation for 12 Months Ending October 30, 2011	Rate Year 2 Adjustments	12 Months Ending October 31, 2011	Subject to Inflation @ 2.10%	Escalation for 12 Months Ending October 31, 2012	12 Months Ending October 31, 2012
1	MGP Sites - Recovery of Deferrals	\$ 1,803	N	-	-	1,803	N	-	1,803
2	Amort MGP RY2 Spending	-	N	-	634	634	N	-	634
3	Amort MGP RY3 Spending	-	N	-	-	-	N	390	390
	Total Environmental Expenses	<u>\$ 1,803</u>		<u>\$ -</u>	<u>\$ 634</u>	<u>\$ 2,437</u>		<u>\$ 390</u>	<u>\$ 2,827</u>

ORANGE & ROCKLAND UTILITIES, INC.
GAS OPERATING PROGRAMS
FOR THE YEARS ENDING OCTOBER 31, 2011 AND OCTOBER 31, 2012

LINE NO.	12 Months Ending October 31, 2010	Subject to Inflation @ 2.12%	Escalation for 12 Months Ending October 30, 2011	Rate Year 2 Adjustments	12 Months Ending October 31, 2011	Subject to Inflation @ 2.10%	Escalation for 12 Months Ending October 31, 2012	12 Months Ending October 31, 2012
1 Thruway Bridge Crossing	\$ 221	Y	5	155	381	Y	8	389
2 Metering Study	-	N	-	50	50	N	35	85
3 System Contingencies	500	Y	11	-	511	Y	11	521
4 Locating Expense	369	Y	8	260	637	Y	13	650
5 Distribution Integrity Mgmt Plan	68	Y	1	47	116	Y	2	119
6 Odorize	53	Y	1	42	96	Y	2	98
7 Gas Rebate Program	211	Y	4	170	385	Y	8	394
8 Additional Vehicle Expense (5 Trucks)	79	Y	2	0	81	Y	2	82
Total Gas Operating Expenses	\$ 1,500		\$ 32	\$ 725	\$ 2,257		\$ 82	\$ 2,339

Orange and Rockland Utilities, Inc.
Gas Rate Case
Plant Depreciation Expense - Proposed Rates
November 2009 to October 2010

Exhibits G-7
Schedule 6
Page 1 of 3

	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10
Gas Plant In Service Beginning Balance:												
Unallocated	-	-	-	-	-	-	-	-	-	-	-	-
Mfg Gas Production Plant	30,537.0	30,533.9	30,530.8	30,527.7	30,524.6	30,521.5	30,518.4	30,515.3	30,512.2	30,509.1	30,506.0	30,502.9
Distribution	401,491.2	412,153.2	414,512.7	415,834.5	417,312.0	418,773.6	420,526.8	422,489.7	425,090.2	427,634.7	430,318.1	435,519.6
Distribution Future	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3
Information System	601.0	601.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0
Intangible Plant	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2
Office Buildings	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9
Office Furniture	119.2	117.0	114.8	112.6	110.4	108.2	106.0	103.8	101.6	99.4	97.2	95.0
Automobiles	169.9	169.9	169.9	169.9	169.9	169.9	169.9	169.9	381.0	381.0	381.0	381.0
Light Trucks	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8
Heavy Trucks	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7
General Equipment	1,315.6	1,350.9	1,394.4	1,430.3	1,466.2	1,502.1	1,538.0	1,573.9	1,609.8	1,645.7	1,681.6	1,717.5
Data Handling Equipment	4,442.5	4,430.6	4,418.7	4,406.8	4,394.9	4,383.0	4,371.1	4,359.2	4,347.3	4,335.4	4,323.5	4,311.6
Easements	-	-	-	-	-	-	-	-	-	-	-	-
Trailers	-	-	-	-	-	-	-	-	-	-	-	-
Total	447,798.4	458,478.4	461,420.3	462,760.8	464,257.0	465,737.3	467,509.2	469,490.8	472,321.1	474,884.3	477,586.4	482,806.6

Gas Plant Additions:

Unallocated	-	-	-	-	-	-	-	-	-	-	-	-
Mfg Gas Production Plant	0	0	0	0	0	0	0	0	0	0	0	0
Distribution	10749.4	2446.9	1409.2	1584.9	1549	1840.6	2050.3	2887.9	2631.9	2770.8	5288.9	13270.3
Distribution Future	0	0	0	0	0	0	0	0	0	0	0	0
Information System	0	556.0	0	0	0	0	0	0	0	0	0	0
Intangible Plant	-	-	-	-	-	-	-	-	-	-	-	-
Office Buildings	-	-	-	-	-	-	-	-	-	-	-	-
Office Furniture	-	-	-	-	-	-	-	-	-	-	-	-
Automobiles	-	-	-	-	-	-	-	211.1	-	-	-	-
Light Trucks	-	-	-	-	-	-	-	-	-	-	-	-
Heavy Trucks	-	-	-	-	-	-	-	-	-	-	-	-
General Equipment	35.3	43.5	35.9	35.9	35.9	35.9	35.9	35.9	35.9	35.9	35.9	35.9
Data Handling Equipment	0	0	0	0	0	0	0	0	0	0	0	0
Easements	-	-	-	-	-	-	-	-	-	-	-	-
Trailers	-	-	-	-	-	-	-	-	-	-	-	-
Total	10,784.7	3,046.4	1,445.1	1,600.8	1,584.9	1,876.5	2,086.2	2,934.9	2,667.8	2,806.7	5,324.8	13,308.2

Gas Plant Retirements:

Unallocated	-	-	-	-	-	-	-	-	-	-	-	-
Mfg Gas Production Plant	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
Distribution	87.4	87.4	87.4	87.4	87.4	87.4	87.4	87.4	87.4	87.4	87.4	87.4
Distribution Future	0	0	0	0	0	0	0	0	0	0	0	0
Information System	0	0	0	0	0	0	0	0	0	0	0	0
Intangible Plant	-	-	-	-	-	-	-	-	-	-	-	-
Office Buildings	-	-	-	-	-	-	-	-	-	-	-	-
Office Furniture	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Automobiles	-	-	-	-	-	-	-	-	-	-	-	-
Light Trucks	-	-	-	-	-	-	-	-	-	-	-	-
Heavy Trucks	-	-	-	-	-	-	-	-	-	-	-	-
General Equipment	-	-	-	-	-	-	-	-	-	-	-	-
Data Handling Equipment	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9
Easements	-	-	-	-	-	-	-	-	-	-	-	-
Trailers	-	-	-	-	-	-	-	-	-	-	-	-
Total	104.6	104.6	104.6	104.6	104.6	104.6	104.6	104.6	104.6	104.6	104.6	104.6

Gas Plant Ending Balance:

Unallocated	-	-	-	-	-	-	-	-	-	-	-	-
Mfg Gas Production Plant	30,533.9	30,530.8	30,527.7	30,524.6	30,521.5	30,518.4	30,515.3	30,512.2	30,509.1	30,506.0	30,502.9	30,499.8
Distribution	412,153.2	414,512.7	415,834.5	417,312.0	418,773.6	420,526.8	422,489.7	425,090.2	427,634.7	430,318.1	435,519.6	448,702.6
Distribution Future	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3
Information System	601.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0
Intangible Plant	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2
Office Buildings	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9
Office Furniture	117.0	114.8	112.6	110.4	108.2	106.0	103.8	101.6	99.4	97.2	95.0	92.8
Automobiles	169.9	169.9	169.9	169.9	169.9	169.9	169.9	381.0	381.0	381.0	381.0	381.0
Light Trucks	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8
Heavy Trucks	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7	2,171.7
General Equipment	1,350.9	1,394.4	1,430.3	1,466.2	1,502.1	1,538.0	1,573.9	1,609.8	1,645.7	1,681.6	1,717.5	1,753.4
Data Handling Equipment	4,430.6	4,418.7	4,406.8	4,394.9	4,383.0	4,371.1	4,359.2	4,347.3	4,335.4	4,323.5	4,311.6	4,299.7
Easements	-	-	-	-	-	-	-	-	-	-	-	-
Trailers	-	-	-	-	-	-	-	-	-	-	-	-
Total	458,478.4	461,420.3	462,760.8	464,257.0	465,737.3	467,509.2	469,490.8	472,321.1	474,884.3	477,586.4	482,806.6	486,008.2

Gas Plant Depreciation Rates:

Unallocated	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Mfg Gas Production Plant	0.001755	0.001755	0.001755	0.001755	0.001755	0.001755	0.001755	0.001755	0.001755	0.001755	0.001755	0.001755
Distribution	0.002087	0.002087	0.002087	0.002087	0.002087	0.002087	0.002087	0.002087	0.002087	0.002087	0.002087	0.002087
Distribution Future	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Information System	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333
Intangible Plant	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Office Buildings	0.002000	0.002000	0.002000	0.002000	0.002000	0.002000	0.002000	0.002000	0.002000	0.002000	0.002000	0.002000
Office Furniture	0.004186	0.004186	0.004186	0.004186	0.004186	0.004186	0.004186	0.004186	0.004186	0.004186	0.004186	0.004186
Automobiles	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375
Light Trucks	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375
Heavy Trucks	0.006800	0.006800	0.006800	0.006800	0.006800	0.006800	0.006800	0.006800	0.006800	0.006800	0.006800	0.006800
General Equipment	0.004146	0.004146	0.004146	0.004146	0.004146	0.004146	0.004146	0.004146	0.004146	0.004146	0.004146	0.004146
Data Handling Equipment	0.003898	0.003898	0.003898	0.003898	0.003898	0.003898	0.003898	0.003898	0.003898	0.003898	0.003898	0.003898
Easements	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Trailers	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000

Gas Plant Depreciation Expense @ 100%:

Unallocated	(45.6)	(45.6)	(45.6)	(45.6)	(45.6)	(45.6)	(45.6)	(45.6)	(45.6)	(45.6)	(45.6)	(45.6)
Mfg Gas Production Plant	53.6	53.6	53.6	53.6	53.6	53.6	53.6	53.6	53.5	53.5	53.5	53.5
Distribution	837.9	860.2	865.1	867.8	870.9	874.0	877.6	881.7	887.2	892.5	898.1	908.9
Distribution Future	-	-	-	-	-	-	-	-	-	-	-	-
Information System	5.0	5.0	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6
Intangible Plant	-	-	-	-	-	-	-	-	-	-	-	-
Office Buildings	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Office Furniture	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.4	0.4
Automobiles	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	3.6	3.6	3.6	3.6
Light Trucks	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Heavy Trucks	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3
General Equipment	5.5	5.6	5.8	5.9	6.1	6.2	6.4	6.5	6.7	6.8	7.0	7.1
Data Handling Equipment	17.3	17.3	17.2	17.2	17.1	17.1	17.0	17.0	16.9	16.9	16.9	16.8
Easements	-	-	-	-	-	-	-	-	-	-	-	-
Trailers	-	-	-	-	-	-	-	-	-	-	-	-
Total	900.9	923.2	932.9	935.8	938.9	942.1	945.8	950.0	957.5	962.9	968.6	979.5

Gas Plant Depreciation Expense Charged to Clearing Accounts @ 100%:

Information System	5.0	5.0	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6
Automobiles	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	3.6	3.6	3.6	3.6
Light Trucks	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Heavy Trucks	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3
General Equipment	5.5	5.6	5.8	5.9	6.1	6.2	6.4	6.5	6.7	6.8	7.0	7.1
Total	36.6	36.7	41.6	41.7	41.9	42.0	42.2	42.3	44.4	44.6	44.7	44.9

Gas Plant Depreciation Expense Charged to Income Statement @ 100%:

Unallocated	-45.6	-45.6	-45.6	-45.6	-45.6	-45.6	-45.6	-45.6	-45.6	-45.6	-45.6	-45.6
Mfg Gas Production Plant	53.6	53.6	53.6	53.6	53.6	53.6	53.6	53.6	53.5	53.5	53.5	53.5
Distribution	837.9	860.2	865.1	867.8	870.9	874.0	877.6	881.7	887.2	892.5	898.1	908.9
Distribution Future	-	-	-	-	-	-	-	-	-	-	-	-
Information System	-	-	-	-	-	-	-	-	-	-	-	-
Intangible Plant	-	-	-	-	-	-	-	-	-	-	-	-
Office Buildings	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Office Furniture	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.4	0.4
Data Handling Equipment	17.3	17.3	17.2	17.2	17.1	17.1	17.0	17.0	16.9	16.9	16.9	16.8
Easements	-	-	-	-	-	-	-	-	-	-	-	-
Trailers	-	-	-	-	-	-	-	-	-	-	-	-
Total	864.3	886.5	891.4	894.1	897.1	900.1	903.7	907.7	913.1	918.3	923.9	934.7

Common Plant @ 100%

Common Plant In Service Beginning Balance:

Unallocated	11,553.9	11,487.2	11,813.5	12,117.5	12,027.5	13,188.9	13,175.2	13,218.5	13,497.6	13,790.7	13,744.9	13,905.5
Information System	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0
Intangible Plant	49,885.8	50,369.9	50,336.6	50,303.2	50,269.8	50,238.4	50,378.4	50,367.5	50,540.0	50,683.3	50,783.3	50,834.2
Office Buildings	3,754.8	3,736.1	3,717.5	3,699.0	3,680.5	3,662.1	3,643.8	3,625.1	3,606.7	3,584.9	3,562.4	3,540.8
Office Furniture	889.2	889.2	889.2	889.2	889.2	889.2	889.2	889.2	1,140.4	1,170.7	1,193.8	1,193.8
Automobiles	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9
Light Trucks	3,769.0	3,882.8	4,390.2	4,390.2	4,390.2	4,390.2	4,892.7	5,480.7	5,881.7	5,814.7	5,814.7	6,462.6
Heavy Trucks	5,509.1	5,577.8	5,665.5	5,665.5	5,678.7	5,717.0	5,769.3	5,837.0	6,209.6	6,227.5	6,285.0	6,437.1
General Equipment	13,601.4	13,570.4	13,539.4	13,508.4	13,477.4	13,446.4	13,415.4	13,384.4	13,353.4	13,322.4	13,291.4	13,260.4
Data Handling Equipment	786.0	786.0	786.0	786.0	786.0	786.0	786.0	786.0	786.0	786.0	786.0	786.0
Easements	-	-	-	-	-	-	-	-	-	-	-	-
Trailers	-	-	-	-	-	-	-	-	-	-	-	-
Total	145,056.1	145,606.2	146,444.7	146,665.8	146,506.1	147,625.0	148,357.0	149,145.4	149,921.3	150,814.1	151,009.4	152,236.1

Common Plant Additions:

Unallocated	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Information System	119.8	512.8	490.5	96.5	1,347.9	172.8	229.8	465.6	479.6	140.7	347.1	253.3
Intangible Plant	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Office Buildings	553.4	36.0	35.9	35.9	37.9	209.3	58.4	241.8	212.6	169.4	120.2	138.7
Office Furniture	2.8	2.7	2.8	2.8	2.9	2.8	2.8	2.9	259.8	2.8	259.7	2.8
Automobiles	0.0	0.0	0.0	0.0	0.0	100.4	150.8	0.0	30.3	0.0	23.1	0.0
Light Trucks	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heavy Trucks	113.8	507.4	0.0	0.0	0.0	502.5	588.0	0.0	201.0	133.0	647.9	141.3
General Equipment	68.7	87.7	0.0	13.2	38.3	52.3	67.7	372.6	17.9	57.5	139.9	15.2
Data Handling Equipment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Easements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Trailers	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	858.3	1,146.6	529.2	148.4	1,427.0	1,040.1	1,097.5	1,082.9	1,201.0	503.4	1,534.9	551.3

Common Plant Retirements:

Unallocated	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Information System	186.5	186.5	186.5	186.5	186.5	186.5	186.5	186.5	186.5	186.5	186.5	186.5
Intangible Plant	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Office Buildings	69.3	69.3	69.3	69.3	69.3	69.3	69.3	69.3	69.3	69.3	69.3	69.3
Office Furniture	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3
Automobiles	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Light Trucks	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heavy Trucks	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
General Equipment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Data Handling Equipment	31.0	31.0	31.0	31.0	31.0	31.0	31.0	31.0	31.0	31.0	31.0	31.0
Easements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Trailers	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	308.1	308.1	308.1	308.1	308.1	308.1	308.1	308.1	308.1	308.1	308.1	308.1

Common Plant Ending Balance:

Unallocated	-	-	-	-	-	-	-	-	-	-	-	-
Information System	11,487.2	11,813.5	12,117.5	12,027.5	13,188.9	13,175.2	13,218.5	13,497.6	13,790.7	13,744.9	13,905.5	13,972.4
Intangible Plant	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0
Office Buildings	50,369.9	50,336.6	50,303.2	50,269.8	50,238.4	50,378.4	50,367.5	50,540.0	50,683.3	50,783.3	50,834.2	50,903.7
Office Furniture	3,736.1	3,717.5	3,699.0	3,680.5	3,662.1	3,643.8	3,625.1	3,606.7	3,584.9	3,562.4	3,540.8	3,519.3
Automobiles	889.2	889.2	889.2	889.2	889.2	889.2	889.2	1,140.4	1,170.7	1,193.8	1,193.8	1,193.8
Light Trucks	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9
Heavy Trucks	3,882.8	4,390.2	4,390.2	4,390.2	4,390.2	4,892.7	5,480.7	5,881.7	5,814.7	5,814.7	6,462.6	6,603.9
General Equipment	5,577.8	5,665.5	5,665.5	5,678.7	5,717.0	5,769.3	5,837.0	6,209.6	6,227.5	6,285.0	6,421.9	6,437.1
Data Handling Equipment	13,570.4	13,539.4	13,508.4	13,477.4	13,446.4	13,415.4	13,384.4	13,353.4	13,322.4	13,291.4	13,260.4	13,229.4
Easements	786.0	786.0	786.0	786.0	786.0	786.0	786.0	786.0	786.0	786.0	786.0	786.0
Trailers	-	-	-	-	-	-	-	-	-	-	-	-
Total	145,606.2	146,444.7	146,665.8	146,506.1	147,625.0	148,357.0	149,145.4	149,921.3	150,814.1	151,009.4	152,236.1	152,479.4

Common Plant Depreciation Rates:

Unallocated	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Information System	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333
Intangible Plant	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Office Buildings	0.002011	0.002011	0.002011	0.002011	0.002011	0.002011	0.002011	0.002011	0.002011	0.002011	0.002011	0.002011
Office Furniture	0.004966	0.004966	0.004966	0.004966	0.004966	0.004966	0.004966	0.004966	0.004966	0.004966	0.004966	0.004966
Automobiles	0.009493	0.009493	0.009493	0.009493	0.009493	0.009493	0.009493	0.009493	0.009493	0.009493	0.009493	0.009493
Light Trucks	0.009391	0.009391	0.009391	0.009391	0.009391	0.009391	0.009391	0.009391	0.009391	0.009391	0.009391	0.009391
Heavy Trucks	0.006632	0.006632	0.006632	0.006632	0.006632	0.006632	0.006632	0.006632	0.006632	0.006632	0.006632	0.006632
General Equipment	0.004247	0.004247	0.004247	0.004247	0.004247	0.004247	0.004247	0.004247	0.004247	0.004247	0.004247	0.004247
Data Handling Equipment	0.004749	0.004749	0.004749	0.004749	0.004749	0.004749	0.004749	0.004749	0.004749	0.004749	0.004749	0.004749
Easements	0.000127	0.000127	0.000127	0.000127	0.000127	0.000127	0.000127	0.000127	0.000127	0.000127	0.000127	0.000127

Common Plant Depreciation Expense @ 100%:

Unallocated	-	-	-	-	-	-	-	-	-	-	-	-
Information System	96.3	95.7	98.4	101.0	100.2	109.9	109.8	110.1	112.5	114.9	114.5	115.9
Intangible Plant - Amortizations	-	-	-	-	-	-	-	-	232.2	232.2	232.2	232.2
CIMS	182.2	182.2	182.2	182.2	182.2	182.2	182.2	182.2	182.2	182.2	182.2	182.2
Retail Access Ph 3 & 4	-	-	-	-	-	-	-	-	-	-	-	-
Plant Field Order Route Design	4.4	4.4	4.4	4.4	4.4	-	-	-	-	-	-	-
Nucon System	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0
Software Data Pipe	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5
EZVMS	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9
Total Amortizations	238.0	238.0	238.0	238.0	238.0	233.6	233.6	233.6	233.6	233.6	233.6	233.6
Office Buildings	100.3	101.3	101.2	101.2	101.1	101.0	101.3	101.3	101.6	101.9	102.1	102.2
Office Furniture	18.6	18.6	18.5	18.4	18.3	18.2	18.1	18.0	17.9	19.1	19.0	20.2
Automobiles	8.4	8.4	8.4	8.4	8.4	8.4	9.4	10.8	10.8	11.1	11.1	11.3
Light Trucks	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4
Heavy Trucks	25.0	25.8	29.1	29.1	29.1	29.1	32.4	36.3	36.3	37.7	38.6	42.9
General Equipment	23.4	23.7	24.1	24.1	24.1	24.3	24.5	24.8	26.4	26.4	26.7	27.3
Data Handling Equipment	64.6	64.4	64.3	64.2	64.0	63.9	63.7	63.6	63.4	63.3	63.1	63.0
Easements	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	594.2	596.4	601.5	603.8	602.8	607.9	612.3	616.1	654.3	659.7	660.5	668.0

Common Plant Depreciation Expense Charged to:

Clearing Accounts:												
Information System	96.3	95.7	98.4	101.0	100.2	109.9	109.8	110.1	112.5	114.9	114.5	115.9
Automobiles	8.4	8.4	8.4	8.4	8.4	8.4	9.4	10.8	10.8	11.1	11.1	11.3
Light Trucks	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4
Heavy Trucks	25.0	25.8	29.1	29.1	29.1	29.1	32.4	36.3	36.3	37.7	38.6	42.9
General Equipment	23.4	23.7	24.1	24.1	24.1	24.3	24.5	24.8	26.4	26.4	26.7	27.3
Total	172.5	173.0	179.5	182.0	181.3	191.1	195.5	201.5	205.4	209.6	210.3	216.7

Common Plant Depreciation Expense Allocated:

Unallocated @ 29.25%	-	-	-	-	-	-	-	-	-	-	-	-
Intangible Plant - Amortizations @ 24.02%	-	-	-	-	-	-	-	-	-	-	-	-
CIMS	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8
Retail Access Ph 3 & 4	-	-	-	-	-	-	-	-	-	-	-	-
Plant Field Order Route Design	1.1	1.1	1.1	1.1	1.1	-	-	-	-	-	-	-
Nucon System	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.8
Software Data Pipe	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
EZVMS	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
Total Amortizations	57.2	57.2	57.2	57.2	57.2	56.1	56.1	56.1	56.1	56.1	56.1	56.1
Office Buildings @ 29.25%	29.3	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.7	29.8	29.9	29.9
Office Furniture @ 29.25%	5.5	5.4	5.4	5.4	5.3	5.3	5.3	5.3	5.2	5.6	5.6	5.9
Data Handling Equipment @ 29.25%	18.9	18.9	18.8	18.8	18.7	18.7	18.6	18.6	18.5	18.5	18.5	18.4
Easements @ 29.25%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Common Depreciation Allocated	110.89	111.10	111.01	110.92	110.83	109.69	109.70	109.62	109.65	110.04	110.03	110.37

Total Gas Depreciation On Income Statement	864.3	886.5	891.4	894.1	897.1	900.1	903.7	907.7	913.1	918.3	923.9	934.7
Total Common Depreciation Alloc On Income	110.9	111.1	111.0	110.9	110.8	109.7	109.7	109.6	109.7	110.0	110.0	110.4
Total Gas Depreciation On Income Statement	975.2	997.6	1,002.4	1,005.0	1,007.9	1,009.8	1,013.4	1,017.3	1,022.7	1,028.4	1,033.9	1,045.0

Twelve Months Ended October 30, 2010

12,158.5

Orange and Rockland Utilities, Inc.
Gas Rate Case
Plant Depreciation Expense - Proposed Rates
November 2010 to October 2011

Exhibits G-7
Schedule 6
Page 2 of 3

	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11
Gas Plant In Service Beginning Balance:												
Unallocated	-	-	-	-	-	-	-	-	-	-	-	-
Mfg Gas Production Plant	30,499.8	30,496.7	30,493.6	30,490.5	30,487.4	30,484.3	30,481.2	30,478.1	30,475.0	30,471.9	30,468.8	30,465.7
Distribution	448,702.6	452,280.3	456,039.5	457,488.5	459,075.5	460,645.0	462,511.1	464,574.8	467,312.6	470,013.3	474,010.6	476,771.9
Distribution Future	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3
Information System	1,157.0	1,157.0	2,401.1	2,401.1	2,401.1	2,401.1	2,401.1	2,401.1	2,401.1	2,401.1	2,401.1	2,401.1
Intangible Plant	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2
Office Buildings	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9
Office Furniture	92.8	90.6	88.4	86.2	84.0	81.8	79.6	77.4	75.2	73.0	70.8	68.6
Automobiles	381.0	381.0	381.0	381.0	381.0	381.0	381.0	381.0	381.0	381.0	381.0	381.0
Light Trucks	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8
Heavy Trucks	2,171.7	2,171.7	2,471.1	2,471.1	2,471.1	2,471.1	2,471.1	2,471.1	2,471.1	2,471.1	2,471.1	2,471.1
General Equipment	1,753.4	1,789.3	1,901.5	1,950.0	1,988.5	2,047.0	2,095.5	2,144.0	2,183.0	2,219.7	2,256.4	2,293.1
Data Handling Equipment	4,299.7	4,287.8	4,275.9	4,272.3	4,268.6	4,264.9	4,261.2	4,257.5	4,253.8	4,250.5	4,247.1	4,243.4
Easements	-	-	-	-	-	-	-	-	-	-	-	-
Trailers	-	-	-	-	-	-	-	-	-	-	-	-
Total	496,008.2	499,604.7	505,002.2	506,490.8	508,117.3	509,726.3	511,631.9	513,735.1	516,503.0	519,241.7	523,277.1	526,086.7

Gas Plant Additions:

Unallocated	-	-	-	-	-	-	-	-	-	-	-	-
Mfg Gas Production Plant	0	0	0	0	0	0	0	0	0	0	0	0
Distribution	3865.1	3846.5	1536.4	1674.4	1656.9	1853.5	2151.1	2825.2	2788.1	4084.7	2848.7	7157.4
Distribution Future	0	0	0	0	0	0	0	0	0	0	0	0
Information System	0	1244.0	0	0	0	0	0	0	0	0	0	0
Intangible Plant	-	-	-	-	-	-	-	-	-	-	-	-
Office Buildings	-	-	-	-	-	-	-	-	-	-	-	-
Office Furniture	-	-	-	-	-	-	-	-	-	-	-	-
Automobiles	-	-	-	-	-	-	-	-	-	-	-	-
Light Trucks	-	-	-	-	-	-	-	-	-	-	-	-
Heavy Trucks	-	299.4	-	-	-	-	-	-	-	-	-	-
General Equipment	35.9	112.2	48.5	48.5	48.5	48.5	48.5	39	36.7	36.7	36.7	36.7
Data Handling Equipment	0	0	8.2	8.2	8.2	8.2	8.2	8.2	18.5	18.5	28.9	28.9
Easements	-	-	-	-	-	-	-	-	-	-	-	-
Trailers	-	-	-	-	-	-	-	-	-	-	-	-
Total	3,701.0	5,502.2	1,593.1	1,731.1	1,713.6	2,010.2	2,207.8	2,872.4	2,843.3	4,140.0	2,914.3	7,223.0

Gas Plant Retirements:

Unallocated	-	-	-	-	-	-	-	-	-	-	-	-
Mfg Gas Production Plant	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
Distribution	87.4	87.4	87.4	87.4	87.4	87.4	87.4	87.4	87.4	87.4	87.4	87.4
Distribution Future	0	0	0	0	0	0	0	0	0	0	0	0
Information System	0	0	0	0	0	0	0	0	0	0	0	0
Intangible Plant	-	-	-	-	-	-	-	-	-	-	-	-
Office Buildings	-	-	-	-	-	-	-	-	-	-	-	-
Office Furniture	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Automobiles	-	-	-	-	-	-	-	-	-	-	-	-
Light Trucks	-	-	-	-	-	-	-	-	-	-	-	-
Heavy Trucks	-	-	-	-	-	-	-	-	-	-	-	-
General Equipment	-	-	-	-	-	-	-	-	-	-	-	-
Data Handling Equipment	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9
Easements	-	-	-	-	-	-	-	-	-	-	-	-
Trailers	-	-	-	-	-	-	-	-	-	-	-	-
Total	104.8	104.6	104.6	104.6	104.6	104.6	104.6	104.6	104.6	104.6	104.6	104.8

Gas Plant Ending Balance:

Unallocated	-	-	-	-	-	-	-	-	-	-	-	-
Mfg Gas Production Plant	30,496.7	30,493.6	30,490.5	30,487.4	30,484.3	30,481.2	30,478.1	30,475.0	30,471.9	30,468.8	30,465.7	30,462.6
Distribution	452,280.3	456,039.5	457,488.5	459,075.5	460,645.0	462,511.1	464,574.8	467,312.6	470,013.3	474,010.6	476,771.9	483,841.9
Distribution Future	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3
Information System	1,157.0	2,401.1	2,401.1	2,401.1	2,401.1	2,401.1	2,401.1	2,401.1	2,401.1	2,401.1	2,401.1	2,401.1
Intangible Plant	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2
Office Buildings	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9
Office Furniture	90.6	88.4	86.2	84.0	81.8	79.6	77.4	75.2	73.0	70.8	68.6	66.4
Automobiles	381.0	381.0	381.0	381.0	381.0	381.0	381.0	381.0	381.0	381.0	381.0	381.0
Light Trucks	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8
Heavy Trucks	2,171.7	2,471.1	2,471.1	2,471.1	2,471.1	2,471.1	2,471.1	2,471.1	2,471.1	2,471.1	2,471.1	2,471.1
General Equipment	1,789.3	1,901.5	1,950.0	1,988.5	2,047.0	2,095.5	2,144.0	2,183.0	2,219.7	2,256.4	2,293.1	2,329.8
Data Handling Equipment	4,287.8	4,275.9	4,272.3	4,268.6	4,264.9	4,261.2	4,257.5	4,253.8	4,250.5	4,247.1	4,243.4	4,301.1
Easements	-	-	-	-	-	-	-	-	-	-	-	-
Trailers	-	-	-	-	-	-	-	-	-	-	-	-
Total	499,604.7	505,002.2	506,490.8	508,117.3	509,726.3	511,631.9	513,735.1	516,503.0	519,241.7	523,277.1	526,086.7	533,205.1

Gas Plant Depreciation Rates:

Unallocated	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Mfg Gas Production Plant	0.001755	0.001755	0.001755	0.001755	0.001755	0.001755	0.001755	0.001755	0.001755	0.001755	0.001755	0.001755
Distribution	0.002087	0.002087	0.002087	0.002087	0.002087	0.002087	0.002087	0.002087	0.002087	0.002087	0.002087	0.002087
Distribution Future	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Information System	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333
Intangible Plant	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Office Buildings	0.002000	0.002000	0.002000	0.002000	0.002000	0.002000	0.002000	0.002000	0.002000	0.002000	0.002000	0.002000
Office Furniture	0.004186	0.004186	0.004186	0.004186	0.004186	0.004186	0.004186	0.004186	0.004186	0.004186	0.004186	0.004186
Automobiles	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375
Light Trucks	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375
Heavy Trucks	0.006600	0.006600	0.006600	0.006600	0.006600	0.006600	0.006600	0.006600	0.006600	0.006600	0.006600	0.006600
General Equipment	0.004146	0.004146	0.004146	0.004146	0.004146	0.004146	0.004146	0.004146	0.004146	0.004146	0.004146	0.004146
Data Handling Equipment	0.003898	0.003898	0.003898	0.003898	0.003898	0.003898	0.003898	0.003898	0.003898	0.003898	0.003898	0.003898
Easements	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Trailers	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000

Gas Plant Depreciation Expense @ 100%:

Unallocated	(45.6)	(45.6)	(45.6)	(45.6)	(45.6)	(45.6)	(45.6)	(45.6)	(45.6)	(45.6)	(45.6)	(45.6)
Mfg Gas Production Plant	53.5	53.5	53.5	53.5	53.5	53.5	53.5	53.5	53.5	53.5	53.5	53.5
Distribution	936.4	943.9	951.8	954.8	958.1	961.4	965.3	969.6	975.3	980.9	989.3	995.0
Distribution Future	-	-	-	-	-	-	-	-	-	-	-	-
Information System	9.6	9.6	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Intangible Plant	-	-	-	-	-	-	-	-	-	-	-	-
Office Buildings	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Office Furniture	0.4	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Automobiles	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Light Trucks	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Heavy Trucks	14.3	14.3	16.3	16.3	16.3	16.3	16.3	16.3	16.3	16.3	16.3	16.3
General Equipment	7.3	7.4	7.9	8.1	8.3	8.5	8.7	8.9	9.1	9.2	9.4	9.5
Data Handling Equipment	16.8	16.7	16.7	16.7	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.7
Easements	-	-	-	-	-	-	-	-	-	-	-	-
Trailers	-	-	-	-	-	-	-	-	-	-	-	-
Total	1,007.1	1,014.7	1,035.3	1,038.5	1,042.0	1,045.4	1,049.5	1,053.9	1,059.8	1,065.6	1,074.1	1,080.1

Gas Plant Depreciation Expense Charged to Clearing Accounts @ 100%:

Information System	9.6	9.6	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Automobiles	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Light Trucks	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Heavy Trucks	14.3	14.3	16.3	16.3	16.3	16.3	16.3	16.3	16.3	16.3	16.3	16.3
General Equipment	7.3	7.4	7.9	8.1	8.3	8.5	8.7	8.9	9.1	9.2	9.4	9.5
Total	45.0	45.2	58.0	58.2	58.4	58.6	58.8	59.0	59.1	59.3	59.5	59.6

Gas Plant Depreciation Expense Charged to Income Statement @ 100%:

Unallocated	-45.6	-45.6	-45.6	-45.6	-45.6	-45.6	-45.6	-45.6	-45.6	-45.6	-45.6	-45.6
Mfg Gas Production Plant	53.5	53.5	53.5	53.5	53.5	53.5	53.5	53.5	53.5	53.5	53.5	53.5
Distribution	936.4	943.9	951.8	954.8	958.1	961.4	965.3	969.6	975.3	980.9	989.3	995.0
Distribution Future	-	-	-	-	-	-	-	-	-	-	-	-
Intangible Plant	-	-	-	-	-	-	-	-	-	-	-	-
Office Buildings	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Office Furniture	0.4	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Data Handling Equipment	16.8	16.7	16.7	16.7	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.7
Easements	-	-	-	-	-	-	-	-	-	-	-	-
Trailers	-	-	-	-	-	-	-	-	-	-	-	-
Total	962.1	969.5	977.3	980.3	983.6	986.8	990.7	995.0	1,000.6	1,006.3	1,014.6	1,020.5

Common Plant @ 100%

Common Plant In Service Beginning Balance:

Unallocated	-	-	-	-	-	-	-	-	-	-	-	-
Information System	13,972.4	13,916.8	13,923.2	13,857.6	13,742.7	13,746.5	13,802.1	13,661.0	13,710.0	13,835.9	13,826.0	14,001.5
Intangible Plant	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0
Office Buildings	50,903.7	50,872.3	50,838.9	50,805.5	50,772.1	50,740.7	50,720.1	50,688.7	50,732.6	50,768.3	50,747.7	50,932.8
Office Furniture	4,046.3	4,027.8	4,009.4	3,991.1	3,972.8	3,954.5	3,936.2	3,917.9	3,899.6	4,139.0	4,120.7	4,360.1
Automobiles	1,193.8	1,193.8	1,193.8	1,193.8	1,193.8	1,193.8	1,244.2	1,344.9	1,344.9	1,395.3	1,395.3	1,445.7
Light Trucks	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9
Heavy Trucks	6,603.9	6,603.9	7,133.4	7,133.4	7,133.4	7,133.4	7,637.5	8,141.6	8,141.6	8,318.0	8,519.8	9,023.9
General Equipment	6,437.1	6,495.8	6,592.7	6,592.7	6,599.9	6,599.9	6,660.3	6,733.0	7,106.7	7,106.7	7,182.2	7,293.5
Data Handling Equipment	13,229.4	13,198.4	13,167.4	13,136.4	13,105.4	13,074.4	13,043.4	13,012.4	12,981.4	12,950.4	12,919.4	12,888.4
Easements	786.0	786.0	786.0	786.0	786.0	786.0	786.0	786.0	786.0	786.0	786.0	786.0
Total	152,479.4	152,401.6	152,951.6	152,803.3	152,612.9	152,574.3	153,136.6	153,592.3	154,009.7	154,674.7	154,803.9	156,036.7

Common Plant Additions:

Unallocated	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Information System	130.9	192.9	120.9	71.6	190.3	242.1	45.4	235.5	312.4	176.6	362.0	40.5
Intangible Plant	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Office Buildings	37.9	35.9	35.9	35.9	37.9	48.7	37.9	113.3	105.0	48.7	254.4	190.5
Office Furniture	2.8	2.9	3.0	3.0	3.0	3.0	3.0	280.7	3.0	260.7	3.0	3.0
Automobiles	0.0	0.0	0.0	0.0	0.0	50.4	100.7	0.0	50.4	0.0	50.4	0.0
Light Trucks	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heavy Trucks	0.0	529.5	0.0	0.0	0.0	504.1	504.1	0.0	176.4	201.8	504.1	201.8
General Equipment	6,495.8	96.9	0.0	7.2	38.3	22.1	72.7	373.7	68.3	7.2	111.3	116.0
Data Handling Equipment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Easements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	230.3	858.1	159.8	117.7	269.5	870.4	763.8	725.5	973.1	437.3	1,542.9	551.8

Common Plant Retirements:

Unallocated	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Information System	186.5	186.5	186.5	186.5	186.5	186.5	186.5	186.5	186.5	186.5	186.5	186.5
Intangible Plant	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Office Buildings	69.3	69.3	69.3	69.3	69.3	69.3	69.3	69.3	69.3	69.3	69.3	69.3
Office Furniture	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3
Automobiles	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Light Trucks	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heavy Trucks	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
General Equipment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Data Handling Equipment	31.0	31.0	31.0	31.0	31.0	31.0	31.0	31.0	31.0	31.0	31.0	31.0
Easements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	308.1	308.1	308.1	308.1	308.1	308.1	308.1	308.1	308.1	308.1	308.1	308.1

Common Plant Ending Balance:

Unallocated	-	-	-	-	-	-	-	-	-	-	-	-
Information System	13,916.8	13,923.2	13,857.6	13,742.7	13,746.5	13,802.1	13,661.0	13,710.0	13,835.9	13,826.0	14,001.5	13,855.5
Intangible Plant	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0
Office Buildings	50,872.3	50,838.9	50,805.5	50,772.1	50,740.7	50,720.1	50,688.7	50,732.6	50,768.3	50,747.7	50,932.8	51,054.0
Office Furniture	4,027.8	4,009.4	3,991.1	3,972.8	3,954.5	3,936.2	3,917.9	3,899.6	4,139.0	4,120.7	4,360.1	4,341.8
Automobiles	1,193.8	1,193.8	1,193.8	1,193.8	1,193.8	1,244.2	1,344.9	1,344.9	1,395.3	1,395.3	1,445.7	1,445.7
Light Trucks	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9
Heavy Trucks	6,603.9	7,133.4	7,133.4	7,133.4	7,133.4	7,637.5	8,141.6	8,141.6	8,318.0	8,519.8	9,023.9	9,225.7
General Equipment	6,495.8	6,592.7	6,592.7	6,599.9	6,638.2	6,660.3	6,733.0	7,106.7	7,106.7	7,182.2	7,293.5	7,409.5
Data Handling Equipment	13,198.4	13,167.4	13,136.4	13,105.4	13,074.4	13,043.4	13,012.4	12,981.4	12,950.4	12,919.4	12,888.4	12,857.4
Easements	786.0	786.0	786.0	786.0	786.0	786.0	786.0	786.0	786.0	786.0	786.0	786.0
Total	152,401.6	152,951.6	152,803.3	152,612.9	152,574.3	153,136.6	153,592.3	154,009.7	154,674.7	154,803.9	156,036.7	156,282.4

Common Plant Depreciation Rates:

Unallocated	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Information System	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333
Intangible Plant	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Office Buildings	0.002011	0.002011	0.002011	0.002011	0.002011	0.002011	0.002011	0.002011	0.002011	0.002011	0.002011	0.002011
Office Furniture	0.004966	0.004966	0.004966	0.004966	0.004966	0.004966	0.004966	0.004966	0.004966	0.004966	0.004966	0.004966
Automobiles	0.009493	0.009493	0.009493	0.009493	0.009493	0.009493	0.009493	0.009493	0.009493	0.009493	0.009493	0.009493
Light Trucks	0.009391	0.009391	0.009391	0.009391	0.009391	0.009391	0.009391	0.009391	0.009391	0.009391	0.009391	0.009391
Heavy Trucks	0.006632	0.006632	0.006632	0.006632	0.006632	0.006632	0.006632	0.006632	0.006632	0.006632	0.006632	0.006632
General Equipment	0.004247	0.004247	0.004247	0.004247	0.004247	0.004247	0.004247	0.004247	0.004247	0.004247	0.004247	0.004247
Data Handling Equipment	0.004749	0.004749	0.004749	0.004749	0.004749	0.004749	0.004749	0.004749	0.004749	0.004749	0.004749	0.004749
Easements	0.000127	0.000127	0.000127	0.000127	0.000127	0.000127	0.000127	0.000127	0.000127	0.000127	0.000127	0.000127

Common Plant Depreciation Expense @ 100%:

Unallocated	-	-	-	-	-	-	-	-	-	-	-	-
Information System	116.4	116.0	116.0	115.5	114.5	114.5	115.0	113.8	114.2	115.3	115.2	116.7
Intangible Plant - Amortizations	232.2	232.2	232.2	232.2	232.2	232.2	232.2	232.2	232.2	232.2	232.2	232.2
CIMS	182.2	182.2	182.2	182.2	182.2	182.2	182.2	182.2	182.2	182.2	182.2	182.2
Retail Access Ph 3 & 4	-	-	-	-	-	-	-	-	-	-	-	-
Plant Field Order Route Design	-	-	-	-	-	-	-	-	-	-	-	-
Nucon System	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0
Software Data Pipe	6.5	-	-	-	-	-	-	-	-	-	-	-
EZVMS	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9
Total Amortizations	233.6	227.1	227.1	227.1	227.1	227.1	227.1	227.1	227.1	227.1	227.1	227.1
Office Buildings	102.4	102.3	102.2	102.2	102.1	102.0	102.0	101.9	102.0	102.1	102.1	102.4
Office Furniture	20.1	20.0	19.9	19.8	19.7	19.6	19.5	19.5	19.4	20.6	20.5	21.7
Automobiles	11.3	11.3	11.3	11.3	11.3	11.3	11.8	12.8	12.8	13.2	13.2	13.7
Light Trucks	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4
Heavy Trucks	43.8	43.8	47.3	47.3	47.3	47.3	50.7	54.0	54.0	55.2	56.5	59.8
General Equipment	27.3	27.6	28.0	28.0	28.0	28.2	28.3	28.6	30.2	30.5	30.5	31.0
Data Handling Equipment	62.8	62.7	62.5	62.4	62.2	62.1	61.9	61.8	61.6	61.5	61.4	61.2
Easements	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	869.5	862.5	866.1	865.3	864.1	864.0	868.1	871.2	873.0	877.1	878.1	885.3

Common Plant Depreciation Expense Charged to:

Clearing Accounts:												
Information System	116.4	116.0	116.0	115.5	114.5	114.5	115.0	113.8	114.2	115.3	115.2	116.7
Automobiles	11.3	11.3	11.3	11.3	11.3	11.3	11.8	12.8	12.8	13.2	13.2	13.7
Light Trucks	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4
Heavy Trucks	43.8	43.8	47.3	47.3	47.3	47.3	50.7	54.0	54.0	55.2	56.5	59.8
General Equipment	27.3	27.6	28.0	28.0	28.0	28.2	28.3	28.6	30.2	30.5	30.5	31.0
Total	218.3	218.1	222.1	221.5	220.6	220.8	225.2	228.6	230.6	233.6	234.9	240.6

Common Plant Depreciation Expense Allocated:

Unallocated @ 29.25%	-	-	-	-	-	-	-	-	-	-	-	-
Intangible Plant - Amortizations @ 24.02%												
CIMS	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8
Retail Access Ph 3 & 4	-	-	-	-	-	-	-	-	-	-	-	-
Plant Field Order Route Design	-	-	-	-	-	-	-	-	-	-	-	-
Nucon System	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6
Software Data Pipe	1.6	-	-	-	-	-	-	-	-	-	-	-
EZVMS	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
Total Amortizations	56.1	54.5	54.5	54.5	54.5	54.5	54.5	54.5	54.5	54.5	54.5	54.5
Office Buildings @ 29.25%	29.9	29.9	29.9	29.9	29.9	29.8	29.8	29.8	29.8	29.9	29.9	30.0
Office Furniture @ 29.25%	5.9	5.9	5.8	5.8	5.8	5.7	5.7	5.7	5.7	6.0	6.0	6.3
Data Handling Equipment @ 29.25%	18.4	18.3	18.3	18.2	18.2	18.2	18.1	18.1	18.0	18.0	17.9	17.9
Easements @ 29.25%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Common Depreciation Allocated	110.34	108.89	108.60	108.51	108.42	108.33	108.25	108.16	108.12	108.44	108.36	108.77

Total Gas Depreciation On Income Statement	962.1	969.5	977.3	980.3	983.6	986.8	990.7	995.0	1,000.6	1,006.3	1,014.6	1,020.5
Total Common Depreciation Alloc On Incom	110.3	108.7	108.6	108.5	108.4	108.3	108.2	108.1	108.1	108.4	108.4	108.8
Total Gas Depreciation On Income Statement	1,072.4	1,078.2	1,085.9	1,088.8	1,092.0	1,095.1	1,098.9	1,103.1	1,108.8	1,114.7	1,123.0	1,129.2

Twelve Months Ended October 30, 2011

13,190.2

	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12
Gas Plant In Service Beginning Balance:												
Unallocated	-	-	-	-	-	-	-	-	-	-	-	-
Mfg Gas Production Plant	30,462.6	30,459.5	30,456.4	30,453.3	30,450.2	30,447.1	30,444.0	30,440.9	30,437.8	30,434.7	30,431.6	30,428.5
Distribution	483,841.9	483,901.4	482,706.1	494,316.3	496,065.4	497,795.2	499,824.2	502,066.5	504,984.8	508,857.5	512,774.3	515,742.1
Distribution Future	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3
Information System	2,401.1	2,401.1	3,652.5	3,652.5	3,652.5	3,652.5	3,652.5	3,652.5	3,652.5	3,652.5	3,652.5	3,652.5
Intangible Plant	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2
Office Buildings	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9
Office Furniture	68.4	64.2	62.0	59.8	57.6	55.4	53.2	51.0	48.8	46.6	44.4	42.2
Automobiles	381.0	381.0	381.0	381.0	381.0	381.0	381.0	381.0	381.0	381.0	381.0	381.0
Light Trucks	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8
Heavy Trucks	2,471.1	2,471.1	2,721.0	2,721.0	2,721.0	2,721.0	2,721.0	2,721.0	2,721.0	2,721.0	2,721.0	2,721.0
General Equipment	2,329.8	2,366.5	2,481.0	2,518.4	2,555.8	2,593.2	2,630.6	2,668.0	2,705.4	2,742.8	2,780.2	2,817.6
Data Handling Equipment	4,301.1	4,328.3	4,331.0	4,327.3	4,323.8	4,319.9	4,316.3	4,312.6	4,308.9	4,315.5	4,322.2	4,339.1
Easements	-	-	-	-	-	-	-	-	-	-	-	-
Trailers	-	-	-	-	-	-	-	-	-	-	-	-
Total	533,205.1	538,323.3	543,741.2	545,379.8	547,157.3	548,915.5	550,972.9	553,243.7	556,190.4	560,101.8	564,057.3	567,074.2

Gas Plant Additions:

Unallocated	-	-	-	-	-	-	-	-	-	-	-	-
Mfg Gas Production Plant	0	0	0	0	0	0	0	0	0	0	0	0
Distribution	5146.9	3892.1	1697.6	1836.5	1817.2	2116.4	2329.7	3005.7	3960.1	4004.2	3055.2	7337.9
Distribution Future	0	0	0	0	0	0	0	0	0	0	0	0
Information System	0	1251.4	0	0	0	0	0	0	0	0	0	0
Intangible Plant	-	-	-	-	-	-	-	-	-	-	-	-
Office Buildings	-	-	-	-	-	-	-	-	-	-	-	-
Office Furniture	-	-	-	-	-	-	-	-	-	-	-	-
Automobiles	-	-	-	-	-	-	-	-	-	-	-	-
Light Trucks	-	-	-	-	-	-	-	-	-	-	-	-
Heavy Trucks	-	249.9	-	-	-	-	-	-	-	-	-	-
General Equipment	36.7	114.5	37.4	37.4	37.4	37.4	37.4	37.4	37.4	37.4	37.4	37.4
Data Handling Equipment	39.2	14.5	8.2	8.2	8.2	8.2	8.2	8.2	16.5	18.5	28.9	28.9
Easements	-	-	-	-	-	-	-	-	-	-	-	-
Trailers	-	-	-	-	-	-	-	-	-	-	-	-
Total	5,222.8	5,522.5	1,743.2	1,882.1	1,862.8	2,162.0	2,375.3	3,051.3	4,016.0	4,060.1	3,121.4	7,404.2

Gas Plant Retirements:

Unallocated	-	-	-	-	-	-	-	-	-	-	-	-
Mfg Gas Production Plant	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
Distribution	87.4	87.4	87.4	87.4	87.4	87.4	87.4	87.4	87.4	87.4	87.4	87.4
Distribution Future	0	0	0	0	0	0	0	0	0	0	0	0
Information System	0	0	0	0	0	0	0	0	0	0	0	0
Intangible Plant	-	-	-	-	-	-	-	-	-	-	-	-
Office Buildings	-	-	-	-	-	-	-	-	-	-	-	-
Office Furniture	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Automobiles	-	-	-	-	-	-	-	-	-	-	-	-
Light Trucks	-	-	-	-	-	-	-	-	-	-	-	-
Heavy Trucks	-	-	-	-	-	-	-	-	-	-	-	-
General Equipment	-	-	-	-	-	-	-	-	-	-	-	-
Data Handling Equipment	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9
Easements	-	-	-	-	-	-	-	-	-	-	-	-
Trailers	-	-	-	-	-	-	-	-	-	-	-	-
Total	104.6	104.6	104.6	104.6	104.6	104.6	104.6	104.6	104.6	104.6	104.6	104.6

Gas Plant Ending Balance:

Unallocated	-	-	-	-	-	-	-	-	-	-	-	-
Mfg Gas Production Plant	30,459.5	30,456.4	30,453.3	30,450.2	30,447.1	30,444.0	30,440.9	30,437.8	30,434.7	30,431.6	30,428.5	30,425.4
Distribution	488,901.4	492,706.1	494,316.3	496,065.4	497,795.2	499,824.2	502,066.5	504,984.8	508,857.5	512,774.3	515,742.1	522,992.6
Distribution Future	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3	210.3
Information System	2,401.1	3,652.5	3,652.5	3,652.5	3,652.5	3,652.5	3,652.5	3,652.5	3,652.5	3,652.5	3,652.5	3,652.5
Intangible Plant	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2	5,359.2
Office Buildings	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9	291.9
Office Furniture	64.2	62.0	59.8	57.6	55.4	53.2	51.0	48.8	46.6	44.4	42.2	40.0
Automobiles	381.0	381.0	381.0	381.0	381.0	381.0	381.0	381.0	381.0	381.0	381.0	381.0
Light Trucks	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8	1,088.8
Heavy Trucks	2,471.1	2,721.0	2,721.0	2,721.0	2,721.0	2,721.0	2,721.0	2,721.0	2,721.0	2,721.0	2,721.0	2,721.0
General Equipment	2,366.5	2,481.0	2,518.4	2,555.8	2,593.2	2,630.6	2,668.0	2,705.4	2,742.8	2,780.2	2,817.6	2,855.0
Data Handling Equipment	4,328.3	4,331.0	4,327.3	4,323.8	4,319.9	4,316.3	4,312.6	4,308.9	4,315.5	4,322.2	4,339.1	4,356.1
Easements	-	-	-	-	-	-	-	-	-	-	-	-
Trailers	-	-	-	-	-	-	-	-	-	-	-	-
Total	538,323.3	543,741.2	545,379.8	547,157.3	548,915.5	550,972.9	553,243.7	556,190.4	560,101.8	564,057.3	567,074.2	574,373.8

Gas Plant Depreciation Rates:

Unallocated	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Mfg Gas Production Plant	0.001755	0.001755	0.001755	0.001755	0.001755	0.001755	0.001755	0.001755	0.001755	0.001755	0.001755	0.001755
Distribution	0.002087	0.002087	0.002087	0.002087	0.002087	0.002087	0.002087	0.002087	0.002087	0.002087	0.002087	0.002087
Distribution Future	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Information System	0.000333	0.000333	0.000333	0.000333	0.000333	0.000333	0.000333	0.000333	0.000333	0.000333	0.000333	0.000333
Intangible Plant	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Office Buildings	0.002000	0.002000	0.002000	0.002000	0.002000	0.002000	0.002000	0.002000	0.002000	0.002000	0.002000	0.002000
Office Furniture	0.004186	0.004186	0.004186	0.004186	0.004186	0.004186	0.004186	0.004186	0.004186	0.004186	0.004186	0.004186
Automobiles	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375
Light Trucks	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375	0.009375
Heavy Trucks	0.006600	0.006600	0.006600	0.006600	0.006600	0.006600	0.006600	0.006600	0.006600	0.006600	0.006600	0.006600
General Equipment	0.004146	0.004146	0.004146	0.004146	0.004146	0.004146	0.004146	0.004146	0.004146	0.004146	0.004146	0.004146
Data Handling Equipment	0.003898	0.003898	0.003898	0.003898	0.003898	0.003898	0.003898	0.003898	0.003898	0.003898	0.003898	0.003898
Easements	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Trailers	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000

Gas Plant Depreciation Expense @ 100%:

Unallocated	(45.6)	(45.6)	(45.6)	(45.6)	(45.6)	(45.6)	(45.6)	(45.6)	(45.6)	(45.6)	(45.6)	(45.6)
Mfg Gas Production Plant	53.5	53.5	53.5	53.4	53.4	53.4	53.4	53.4	53.4	53.4	53.4	53.4
Distribution	1,009.8	1,020.3	1,028.3	1,031.6	1,035.3	1,038.9	1,043.1	1,047.8	1,053.9	1,062.0	1,070.2	1,076.4
Distribution Future	-	-	-	-	-	-	-	-	-	-	-	-
Information System	20.0	20.0	30.4	30.4	30.4	30.4	30.4	30.4	30.4	30.4	30.4	30.4
Intangible Plant	-	-	-	-	-	-	-	-	-	-	-	-
Office Buildings	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Office Furniture	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Automobiles	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Light Trucks	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Heavy Trucks	16.3	16.3	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0
General Equipment	9.7	9.8	10.3	10.4	10.6	10.8	10.9	11.1	11.2	11.4	11.5	11.7
Data Handling Equipment	16.8	16.9	16.9	16.9	16.9	16.8	16.8	16.8	16.8	16.8	16.8	16.9
Easements	-	-	-	-	-	-	-	-	-	-	-	-
Trailers	-	-	-	-	-	-	-	-	-	-	-	-
Total	1,095.0	1,105.8	1,126.3	1,129.8	1,133.6	1,137.3	1,141.7	1,146.5	1,152.7	1,160.9	1,169.3	1,175.7

Gas Plant Depreciation Expense Charged to Clearing Accounts @ 100%:

Information System	20.0	20.0	30.4	30.4	30.4	30.4	30.4	30.4	30.4	30.4	30.4	30.4
Automobiles	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Light Trucks	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Heavy Trucks	16.3	16.3	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0
General Equipment	9.7	9.8	10.3	10.4	10.6	10.8	10.9	11.1	11.2	11.4	11.5	11.7
Total	59.8	59.9	72.5	72.6	72.8	72.9	73.1	73.2	73.4	73.5	73.7	73.9

Gas Plant Depreciation Expense Charged to Income Statement @ 100%:

Unallocated	-45.6	-45.6	-45.6	-45.6	-45.6	-45.6	-45.6	-45.6	-45.6	-45.6	-45.6	-45.6
Mfg Gas Production Plant	53.5	53.5	53.5	53.4	53.4	53.4	53.4	53.4	53.4	53.4	53.4	53.4
Distribution	1,009.8	1,020.3	1,028.3	1,031.6	1,035.3	1,038.9	1,043.1	1,047.8	1,053.9	1,062.0	1,070.2	1,076.4
Distribution Future	-	-	-	-	-	-	-	-	-	-	-	-
Information System	-	-	-	-	-	-	-	-	-	-	-	-
Intangible Plant	-	-	-	-	-	-	-	-	-	-	-	-
Office Buildings	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Office Furniture	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Data Handling Equipment	16.8	16.9	16.9	16.9	16.9	16.8	16.8	16.8	16.8	16.8	16.8	16.9
Easements	-	-	-	-	-	-	-	-	-	-	-	-
Trailers	-	-	-	-	-	-	-	-	-	-	-	-
Total	1,035.3	1,045.9	1,053.9	1,057.2	1,060.8	1,064.4	1,068.6	1,073.2	1,079.3	1,087.4	1,095.6	1,101.8

Common Plant @ 100%

Common Plant In Service Beginning Balance:

Unallocated	-	-	-	-	-	-	-	-	-	-	-	-
Information System	13,855.5	13,727.3	15,103.2	15,706.1	15,600.6	16,808.4	16,809.6	16,554.4	16,901.7	16,882.2	24,876.1	25,186.3
Intangible Plant	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0
Office Buildings	51,054.0	51,401.2	52,670.8	52,637.4	52,604.0	52,572.6	52,539.2	52,662.3	52,628.9	52,597.5	52,986.3	53,253.7
Office Furniture	4,341.8	4,323.5	4,305.2	4,288.9	4,268.6	4,250.3	4,232.0	4,213.7	4,195.4	4,177.1	4,158.8	4,140.5
Automobiles	1,445.7	1,510.0	1,510.0	1,510.0	1,510.0	1,510.0	1,610.7	1,661.1	1,661.1	1,761.8	1,812.2	1,862.6
Light Trucks	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9
Heavy Trucks	9,329.1	9,329.1	9,881.4	9,881.4	9,881.4	9,881.4	10,082.9	10,385.2	10,385.2	10,586.7	10,788.2	11,090.5
General Equipment	7,409.5	7,447.9	7,507.8	7,507.8	7,515.0	7,553.3	7,605.7	7,632.9	7,729.0	7,734.1	7,804.5	8,000.3
Data Handling Equipment	12,857.4	12,826.4	12,795.4	12,764.4	12,733.4	12,702.4	12,671.4	12,640.4	12,609.4	12,578.4	12,547.4	12,516.4
Easements	786.0	786.0	786.0	786.0	786.0	786.0	786.0	786.0	786.0	786.0	786.0	786.0
Total	156,282.4	156,856.2	159,866.6	160,388.8	160,205.8	161,171.2	161,444.3	161,842.8	162,203.5	162,410.6	171,066.3	172,143.1

Common Plant Additions:

Unallocated	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Information System	58.3	1,562.4	789.4	81.0	1,194.3	187.7	131.3	533.8	167.0	8,180.4	496.7	137.9
Intangible Plant	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Office Buildings	416.5	1,338.9	35.9	35.9	37.9	35.9	192.3	35.9	37.9	458.1	336.7	35.9
Office Furniture	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Automobiles	64.3	0.0	0.0	0.0	0.0	100.7	50.4	0.0	100.7	50.4	50.4	100.7
Light Trucks	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heavy Trucks	103.4	552.3	0.0	0.0	0.0	201.5	302.3	0.0	201.5	201.5	302.3	302.3
General Equipment	38.4	59.9	0.0	7.2	36.3	52.4	27.2	96.1	5.1	70.4	195.8	10.3
Data Handling Equipment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Easements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	693.9	3,516.5	828.3	127.1	1,273.5	581.2	708.5	668.8	515.2	8,963.8	1,384.9	590.1

Common Plant Retirements:

Unallocated	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Information System	186.5	186.5	186.5	186.5	186.5	186.5	186.5	186.5	186.5	186.5	186.5	186.5
Intangible Plant	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Office Buildings	69.3	69.3	69.3	69.3	69.3	69.3	69.3	69.3	69.3	69.3	69.3	69.3
Office Furniture	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3
Automobiles	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Light Trucks	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heavy Trucks	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
General Equipment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Data Handling Equipment	31.0	31.0	31.0	31.0	31.0	31.0	31.0	31.0	31.0	31.0	31.0	31.0
Easements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	308.1	308.1	308.1	308.1	308.1	308.1	308.1	308.1	308.1	308.1	308.1	308.1

Common Plant Ending Balance:

Unallocated	-	-	-	-	-	-	-	-	-	-	-	-
Information System	13,727.3	15,103.2	15,706.1	15,600.6	16,808.4	16,809.6	16,554.4	16,901.7	16,882.2	24,876.1	25,186.3	25,137.7
Intangible Plant	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0	53,241.0
Office Buildings	51,401.2	52,670.8	52,637.4	52,604.0	52,572.6	52,539.2	52,662.3	52,628.9	52,597.5	52,986.3	53,253.7	53,220.3
Office Furniture	4,323.5	4,305.2	4,286.9	4,268.6	4,250.3	4,232.0	4,213.7	4,195.4	4,177.1	4,158.8	4,140.5	4,122.2
Automobiles	1,510.0	1,510.0	1,510.0	1,510.0	1,510.0	1,610.7	1,661.1	1,661.1	1,761.8	1,812.2	1,862.6	1,963.3
Light Trucks	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9	2,065.9
Heavy Trucks	9,329.1	9,881.4	9,881.4	9,881.4	9,881.4	10,082.9	10,385.2	10,385.2	10,586.7	10,788.2	11,090.5	11,392.8
General Equipment	7,447.9	7,507.8	7,507.8	7,515.0	7,553.3	7,605.7	7,632.9	7,729.0	7,734.1	7,804.5	8,000.3	8,010.6
Data Handling Equipment	12,826.4	12,795.4	12,764.4	12,733.4	12,702.4	12,671.4	12,640.4	12,609.4	12,578.4	12,547.4	12,516.4	12,485.4
Easements	786.0	786.0	786.0	786.0	786.0	786.0	786.0	786.0	786.0	786.0	786.0	786.0
Total	156,558.2	159,866.6	160,388.8	160,205.8	161,171.2	161,444.3	161,842.8	162,203.5	162,410.6	171,066.3	172,143.1	172,425.1

Common Plant Depreciation Rates:

Unallocated	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Information System	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333	0.008333
Intangible Plant	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Office Buildings	0.002011	0.002011	0.002011	0.002011	0.002011	0.002011	0.002011	0.002011	0.002011	0.002011	0.002011	0.002011
Office Furniture	0.004966	0.004966	0.004966	0.004966	0.004966	0.004966	0.004966	0.004966	0.004966	0.004966	0.004966	0.004966
Automobiles	0.009493	0.009493	0.009493	0.009493	0.009493	0.009493	0.009493	0.009493	0.009493	0.009493	0.009493	0.009493
Light Trucks	0.009391	0.009391	0.009391	0.009391	0.009391	0.009391	0.009391	0.009391	0.009391	0.009391	0.009391	0.009391
Heavy Trucks	0.006632	0.006632	0.006632	0.006632	0.006632	0.006632	0.006632	0.006632	0.006632	0.006632	0.006632	0.006632
General Equipment	0.004247	0.004247	0.004247	0.004247	0.004247	0.004247	0.004247	0.004247	0.004247	0.004247	0.004247	0.004247
Data Handling Equipment	0.004749	0.004749	0.004749	0.004749	0.004749	0.004749	0.004749	0.004749	0.004749	0.004749	0.004749	0.004749
Easements	0.000127	0.000127	0.000127	0.000127	0.000127	0.000127	0.000127	0.000127	0.000127	0.000127	0.000127	0.000127

Common Plant Depreciation Expense @ 100%:

Unallocated	-	-	-	-	-	-	-	-	-	-	-	-
Information System	115.5	114.4	125.9	130.9	130.0	138.4	138.4	137.9	140.8	140.7	207.3	209.9
Intangible Plant - Amortizations	232.2	232.2	232.2	232.2	232.2	232.2	232.2	232.2	232.2	232.2	232.2	232.2
CIMS	182.2	182.2	182.2	182.2	182.2	182.2	182.2	182.2	182.2	182.2	182.2	182.2
Retail Access Ph 3 & 4	-	-	-	-	-	-	-	-	-	-	-	-
Plant Field Order Route Design	-	-	-	-	-	-	-	-	-	-	-	-
Nucon System	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	-	-
Software Data Pipe	-	-	-	-	-	-	-	-	-	-	-	-
EZVMS	8.9	8.9	8.9	8.9	8.9	-	-	-	-	-	-	-
Total Amortizations	227.1	227.1	227.1	227.1	227.1	218.2	218.2	218.2	218.2	218.2	182.2	182.2
Office Buildings	102.7	103.4	105.9	105.9	105.8	105.7	105.7	105.9	105.8	105.8	106.6	107.1
Office Furniture	21.6	21.5	21.4	21.3	21.2	21.1	21.0	20.9	20.8	20.7	20.7	20.6
Automobiles	13.7	14.3	14.3	14.3	14.3	14.3	15.3	15.8	15.8	16.7	17.2	17.7
Light Trucks	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4
Heavy Trucks	61.2	61.9	65.5	65.5	65.5	66.9	68.9	68.9	68.9	70.2	71.5	73.6
General Equipment	31.5	31.8	31.9	31.9	31.9	32.1	32.3	32.4	32.8	32.8	33.1	34.0
Data Handling Equipment	61.1	60.9	60.8	60.6	60.5	60.3	60.2	60.0	59.9	59.7	59.6	58.4
Easements	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	885.9	886.8	904.5	909.2	908.0	907.4	909.6	911.8	914.8	915.6	949.9	956.1

Common Plant Depreciation Expense Charged to:

Clearing Accounts:												
Information System	115.5	114.4	125.9	130.9	130.0	138.4	138.4	137.9	140.8	140.7	207.3	209.9
Automobiles	13.7	14.3	14.3	14.3	14.3	14.3	15.3	15.8	15.8	16.7	17.2	17.7
Light Trucks	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4
Heavy Trucks	61.2	61.9	65.5	65.5	65.5	66.9	68.9	68.9	68.9	70.2	71.5	73.6
General Equipment	31.5	31.6	31.9	31.9	31.9	32.1	32.3	32.4	32.8	32.8	33.1	34.0
Total	241.2	241.6	257.0	262.0	261.2	269.7	272.3	274.4	277.7	279.9	348.6	354.5

Common Plant Depreciation Expense Allocated:

Unallocated @ 29.25%	-	-	-	-	-	-	-	-	-	-	-	-
Intangible Plant - Amortizations @ 24.02%												
CIMS	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8
Retail Access Ph 3 & 4	-	-	-	-	-	-	-	-	-	-	-	-
Plant Field Order Route Design	-	-	-	-	-	-	-	-	-	-	-	-
Nucon System	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	-	-
Software Data Pipe	-	-	-	-	-	-	-	-	-	-	-	-
EZVMS	2.1	2.1	2.1	2.1	2.1	-	-	-	-	-	-	-
Total Amortizations	54.5	54.5	54.5	54.5	54.5	52.4	52.4	52.4	52.4	52.4	43.8	43.8
Office Buildings @ 29.25%	30.0	30.2	31.0	31.0	30.9	30.9	30.9	31.0	31.0	30.9	31.2	31.3
Office Furniture @ 29.25%	6.3	6.3	6.3	6.2	6.2	6.2	6.1	6.1	6.1	6.1	6.0	6.0
Data Handling Equipment @ 29.25%	17.9	17.8	17.8	17.7	17.7	17.6	17.6	17.6	17.5	17.5	17.4	17.4
Easements @ 29.25%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Common Depreciation Allocated	108.78	108.91	109.59	109.50	109.41	107.18	107.09	107.10	107.01	106.92	98.43	98.52

Total Gas Depreciation On Income Statement	1,035.3	1,045.9	1,053.9	1,057.2	1,060.8	1,064.4	1,068.6	1,073.2	1,079.3	1,087.4	1,095.6	1,101.8
Total Common Depreciation Alloc On Income	108.8	108.9	109.6	109.5	109.4	107.2	107.1	107.1	107.0	106.9	98.4	98.5
Total Gas Depreciation On Income Statement	1,144.0	1,154.8	1,163.4	1,166.7	1,170.2	1,171.6	1,175.7	1,180.3	1,186.3	1,194.3	1,194.0	1,200.3

Twelve Months Ended October 30, 2012

14,101.8

Orange & Rockland Utilities, Inc.
Gas Department
Taxes Other than Income Taxes
For the Twelve Months Ending October 31, 2011
(\$000's)

Exhibit G-7
Schedule 7

	2010 As Reflected in Exhibit G-4 and G-5	2011 Adjustments	2011 As Adjusted	Changes	Adjusted
STATE, COUNTY & TOWN - PAYMENTS	2,540	125	2,665	-	2,665
- TAX TRUE UP (DEFERRAL)	-	-	-	-	-
VILLAGE - PAYMENTS	603	36	639	-	639
- TAX TRUE UP (DEFERRAL)	-	-	-	-	-
SCHOOL - PAYMENTS	6,793	379	7,172	-	7,172
- TAX TRUE UP (DEFERRAL)	-	-	-	-	-
AMORT. OF PROPERTY TAX DEFERRAL (A/C 25437)	(240)	-	(240)	-	(240)
PROPERTY TAX REFUNDS 05-G-1494 (A/C 254535)	-	-	-	-	-
PROPERTY TAX REFUNDS (A/C 254398 / 254399)	(24)	-	(24)	-	(24)
TOTAL PROPERTY TAXES	9,672	541	10,213	-	10,213
Payroll Taxes	1,121	55	1,176	-	1,176
Revenue Taxes	2,433	(13)	2,420	71	2,491
Other Taxes:					-
Franchise Tax	45	1	46	-	46
All other Taxes	23	-	23	-	23
Other Taxes	68	1	69	-	69
Total Other than income tax	13,294	584	13,878	71	13,949
Less: Gross Receipts Taxes	(2,433)	13	(2,420)	(71)	(2,491)
Total Excluding GRT	10,861	597	11,458	-	11,458

For the Twelve Months Ending October 31, 2012
(\$000's)

	2011 As Reflected in \$0	2012 Adjustments	2012 As Adjusted	Changes	Adjusted
STATE, COUNTY & TOWN - PAYMENTS	2,665	125	2,790	-	2,790
- TAX TRUE UP (DEFERRAL)	-	-	-	-	-
VILLAGE - PAYMENTS	639	36	675	-	675
- TAX TRUE UP (DEFERRAL)	-	-	-	-	-
SCHOOL - PAYMENTS	7,172	380	7,552	-	7,552
- TAX TRUE UP (DEFERRAL)	-	-	-	-	-
AMORT. OF PROPERTY TAX DEFERRAL (A/C 25437)	(240)	-	(240)	-	(240)
PROPERTY TAX REFUNDS 05-G-1494 (A/C 254535)	-	-	-	-	-
PROPERTY TAX REFUNDS (A/C 254398 / 254399)	(24)	-	(24)	-	(24)
TOTAL PROPERTY TAXES	10,213	541	10,754	-	10,754
Payroll Taxes	1,176	36	1,212	-	1,212
Revenue Taxes	2,491	48	2,539	39	2,578
Other Taxes:					-
Franchise Tax	46	1	47	-	47
All other Taxes	23	-	23	-	23
Other Taxes	69	1	70	-	-
Total Other than income tax	13,949	626	14,575	39	14,614
Less: Gross Receipts Taxes	(2,491)	(48)	(2,539)	(39)	(2,578)
Total Excluding GRT	11,458	578	12,036	-	12,036

Orange & Rockland Utilities, Inc.
Gas Department
New York State Income Tax
Twelve Months Ending October 31, 2011
(\$000's)

Exhibit E-7
Schedule 8
Page 1 of 2

	2010 As Reflected in Exhibit E-4 and E-5	2011 Adjustments	2011 As Adjusted	Changes	Adjusted
Operating Income Before Income Taxes	33,532	(2,991)	30,540	6,856	37,396
<u>Additions: Taxable Income & Unallowable Deductions</u>					
UNALLOWABLE BUSINESS EXPENSE	-	-	-	-	-
NON TAXABLE INCOME, UNALLOWABLE DEDUCTIONS	-	-	-	-	-
Total Deductions	-	-	-	-	-
<u>Deduct: Non Taxable Inc. & Add'l Deductions</u>					
INTEREST EXPENSE	10,460	\$1,565	12,025	-	12,025
MEDICARE REIMBURSEMENT	735	-	735	-	735
Total Deductions	11,195	1,565	12,760	-	12,760
Pre Tax Income	22,337	(4,556)	17,780	6,856	24,636
<u>SECTION II - NORMALIZED ITEMS</u>					
ADD ADDITIONAL TAXABLE INCOME AND					
UNALLOWABLE DEDUCTIONS:					
BOOK DEPRECIATION - EXPENSE	10,650	1,031	11,681	-	11,681
- CHARGED TO CLEARING	2,084	301	2,385	-	2,385
AMORTIZATION - COMPUTER SOFTWARE	679	(23)	656	-	656
VEHICLE LEASE EXPENSE OVER TAX DEPRECIATION	11	49	60	-	60
CAPITALIZED INTEREST	-	-	-	-	-
GENERAL LIABILITY INSURANCE	-	-	-	-	-
WORKMEN'S COMPENSATION	-	-	-	-	-
EXCESS OF BOOK RESERVE OVER UB WRITE-OFFS	-	-	-	-	-
INCREASE IN DEFERRED FUEL COST	5,761	(4,434)	1,327	-	1,327
AMORTIZATION OF RATE CASE COST	18	-	18	-	18
AMORTIZATION OF BOND REDEMPTION COSTS	83	-	83	-	83
AMORTIZATION OF RECOVERED MTA TAX	-	-	-	-	-
MEDICARE REIMBURSEMENT	(423)	-	(423)	-	(423)
POST EMPLOYMENT BENEFITS EXPENSE	3,320	72	3,392	-	3,392
DEFERRED STATE INCOME TAX NON DEDUCTIBLE	-	-	-	-	-
CONTRIBUTIONS IN AID OF CONSTRUCTION	685	-	685	-	685
ENVIRONMENTAL RESERVE	21	-	21	-	21
REVENUE SUBJECT TO REFUND	-	-	-	-	-
UNALLOWABLE BOOK PENSION EXPENSE	7,666	(1,213)	6,453	-	6,453
LOW INCOME/ CUSTOMER OUTREACH	-	-	-	-	-
GAS STRANDED COSTS SURCHARGE RECOVERIES	-	-	-	-	-
PROPERTY TAX REFUND - NET 481H	-	-	-	-	-
TOTAL NORMALIZED ADDITIONS	30,555	(4,217)	26,338	-	26,338
DEDUCT NONTAXABLE INCOME AND ADDITIONAL					
ALLOWABLE DEDUCTIONS:					
NYS TAX DEPRECIATION - EXISTING BOOK RATES	21,130	2,231	23,361	-	23,361
SECTION 263A DEDUCTION (CAPITALIZED OVERHEADS)	6,072	182	6,254	-	6,254
COST OF REMOVAL	685	(4)	681	-	681
TAX OVER BOOK - BH LEASE	-	-	-	-	-
LIEN DATE PROPERTY TAX DEDUCTION	98	11	109	-	109
AFUDC	-	-	-	-	-
LOSS ON DISPOSITION OF PROPERTY	173	-	173	-	173
PENSION FUNDING	8,348	28,188	36,536	-	36,536
SUPPLEMENTAL PENSION	525	(19)	506	-	506
OPEB FUNDING	2,676	714	3,390	-	3,390
AMORTIZATION OF CONSERVATION COSTS	68	-	68	-	68
LTP AND STOCK OPTIONS	-	-	-	-	-
RESERVE FOR MEDICAL INSURANCE	-	-	-	-	-
INTEREST - ALGONQUIN CAPACITY PAYMENT	-	-	-	-	-
MERCHANT FUNCTION CHARGE	-	-	-	-	-
PHASE IN OF RATE RELIEF 05-G-1494	-	-	-	-	-
MTA TAX DEFERRED	-	-	-	-	-
GAS IN STORAGE CARRYING CHARGE	570	-	570	-	570
ENVIRONMENTAL COST - QER EXPEND. SECT. 198	991	-	991	-	991
TOTAL	41,336	31,303	72,639	-	72,639
TAXABLE INCOME OR (LOSS)	11,556	(40,076)	(28,519)	6,856	(21,664)
<u>SUMMARY OF STATE INCOME TAXES</u>					
CURRENT STATE INCOME TAXES @ 7.1%	820	(2,845)	(2,025)	487	(1,538)
DEFERRED STATE INCOME TAXES @ 7.1%	765	2,522	3,287	-	3,287
TOTAL CURRENT PERIOD SIT	1,585	(323)	1,262	487	1,749
MTA TAX @ 1.53%	-	-	-	-	-
DEFERRED STATE MTA TAXES @ 1.53%	-	-	-	-	-
PRIOR PERIOD OVER / UNDER ACCRUAL	-	-	-	-	-
NYS INCOME TAX	1,585	(323)	1,262	487	1,749

Orange & Rockland Utilities, Inc.
Gas Department
New York State Income Tax
Twelve Months Ending October 31, 2012
(\$000's)

Exhibit E-7
Schedule 8
Page 2 of 2

	2011 As Reflected in Exhibit E-4 and E-5	2012 Adjustments	2012 As Adjusted	Changes	Adjusted
Operating Income Before Income Taxes	37,396	(637)	36,759	3,817	40,576
<u>Additions: Taxable Income & Unallowable Deductions</u>					
UNALLOWABLE BUSINESS EXPENSE	-	-	-	-	-
NON TAXABLE INCOME, UNALLOWABLE DEDUCTIONS	-	-	-	-	-
Total Deductions	-	-	-	-	-
<u>Deduct: Non Taxable Inc. & Add'l Deductions</u>					
INTEREST EXPENSE	12,025	\$1,056	13,081	-	13,081
MEDICARE REIMBURSEMENT	735	-	735	-	735
Total Deductions	12,760	1,056	13,816	-	13,816
Pre Tax Income	24,636	(1,693)	22,943	3,817	26,760
<u>SECTION II - NORMALIZED ITEMS</u>					
ADD ADDITIONAL TAXABLE INCOME AND					
UNALLOWABLE DEDUCTIONS:					
BOOK DEPRECIATION - EXPENSE	11,681	773	12,454	-	12,454
- CHARGED TO CLEARING	2,385	523	2,908	-	2,908
AMORTIZATION -- COMPUTER SOFTWARE	656	(34)	622	-	622
VEHICLE LEASE EXPENSE OVER TAX DEPRECIATION	60	(69)	(10)	-	(10)
CAPITALIZED INTEREST	-	-	-	-	-
GENERAL LIABILITY INSURANCE	-	-	-	-	-
WORKMEN'S COMPENSATION	-	-	-	-	-
EXCESS OF BOOK RESERVE OVER UB WRITEOFFS	-	-	-	-	-
INCREASE IN DEFERRED FUEL COST	1,327	(433)	894	-	894
AMORTIZATION OF RATE CASE COST	18	-	18	-	18
AMORTIZATION OF BOND REDEMPTION COSTS	83	-	83	-	83
AMORTIZATION OF RECOVERED MTA TAX	-	-	-	-	-
MEDICARE REIMBURSEMENT	(423)	-	(423)	-	(423)
POST EMPLOYMENT BENEFITS EXPENSE	3,392	(27)	3,365	-	3,365
DEFERRED STATE INCOME TAX NON DEDUCTIBLE	-	-	-	-	-
CONTRIBUTIONS IN AID OF CONSTRUCTION	685	-	685	-	685
ENVIRONMENTAL RESERVE	21	-	21	-	21
REVENUE SUBJECT TO REFUND	-	-	-	-	-
UNALLOWABLE BOOK PENSION EXPENSE	6,453	(1,188)	5,265	-	5,265
LOW INCOME/ CUSTOMER OUTREACH	-	-	-	-	-
GAS STRANDED COSTS SURCHARGE RECOVERIES	-	-	-	-	-
PROPERTY TAX REFUND - NET 461H	-	-	-	-	-
TOTAL NORMALIZED ADDITIONS	26,338	(456)	25,883	-	25,883
DEDUCT NONTAXABLE INCOME AND ADDITIONAL					
ALLOWABLE DEDUCTIONS:					
NYS TAX DEPRECIATION - EXISTING BOOK RATES	23,361	2,202	25,563	-	25,563
SECTION 283A DEDUCTION (CAPITALIZED OVERHEADS)	6,254	(16)	6,238	-	6,238
COST OF REMOVAL	681	(468)	214	-	214
TAX OVER BOOK -- BH LEASE	-	-	-	-	-
LIEN DATE PROPERTY TAX DEDUCTION	109	-	109	-	109
AFUDC	-	-	-	-	-
LOSS ON DISPOSITION OF PROPERTY	173	-	173	-	173
PENSION FUNDING	36,536	(17,053)	19,483	-	19,483
SUPPLEMENTAL PENSION	506	(9)	497	-	497
OPEB FUNDING	3,390	22	3,412	-	3,412
AMORTIZATION OF CONSERVATION COSTS	68	-	68	-	68
LTIP AND STOCK OPTIONS	-	-	-	-	-
RESERVE FOR MEDICAL INSURANCE	-	-	-	-	-
INTEREST -- ALGONQUIN CAPACITY PAYMENT	-	-	-	-	-
MERCHANT FUNCTION CHARGE	-	-	-	-	-
PHASE IN OF RATE RELIEF 05-G-1494	-	-	-	-	-
MTA TAX DEFERRED	-	-	-	-	-
GAS IN STORAGE CARRYING CHARGE	570	-	570	-	570
ENVIRONMENTAL COST - QER EXPEND. SECT. 198	991	-	991	-	991
TOTAL	72,639	(15,322)	57,317	-	57,317
TAXABLE INCOME OR (LOSS)	(21,665)	13,174	(8,491)	3,817	(4,674)
<u>SUMMARY OF STATE INCOME TAXES</u>					
CURRENT STATE INCOME TAXES @ 7.1%	(1,538)	935	(603)	271	(332)
DEFERRED STATE INCOME TAXES @ 7.1%	3,287	(1,056)	2,232	-	2,232
TOTAL CURRENT PERIOD SIT	1,749	(121)	1,629	271	1,900
MTA TAX @ 1.53%	-	-	-	-	-
DEFERRED STATE MTA TAXES @ 1.53%	-	-	-	-	-
PRIOR PERIOD OVER / UNDER ACCRUAL	-	-	-	-	-
NYS INCOME TAX	1,749	(121)	1,629	271	1,900

Orange & Rockland Utilities, Inc.
Gas Department
Federal Income Tax
Twelve Months Ending October 31, 2011
(\$000's)

Exhibit E-7
Schedule 9
Page 1 of 2

	2010 As Reflected in Exhibit G-4 and G-5	2011 Adjustments	2011 As Adjusted	Changes	Adjusted
Operating Income Before Income Taxes	\$33,532	\$ (2,991)	\$30,540	\$6,856	\$37,396
New York State Income Taxes	1,585	(323)	1,262	487	1,749
Book Operating Income before FIT	31,947	(2,668)	29,279	6,369	35,647
<u>Flow Through Items</u>					
<u>Add: Additional Income and Unallowable Deductions</u>					
BOOK DEPRECIATION - CHARGED TO EXPENSE	10,650	1,031	11,681	-	11,681
- CHARGED TO CLEARING	2,084	301	2,385	-	2,385
Capitalized Interest	-	-	-	-	-
UNALLOWABLE BUSINESS EXPENSE	-	-	-	-	-
NON TAXABLE INCOME, UNALLOWABLE DEDUCTIONS	-	-	-	-	-
Total Additions	12,734	1,332	14,066	-	14,066
<u>Deduct: Non-Taxable Income and Additional Deductions</u>					
Interest Expense	10,460	1,565	12,025	-	12,025
STATUTORY DEPRECIATION - CURRENT BOOK RATES	11,486	1,010	12,496	-	12,496
- PROPOSED BOOK RATES	(335)	33	(302)	-	(302)
COST OF REMOVAL	685	(4)	681	-	681
MEDICARE REIMBURSEMENT	735	-	735	-	735
LIEN DATE PROPERTY TAX DEDUCTION	98	11	109	-	109
AFUDC	-	-	-	-	-
LOSS ON DISPOSITION OF PROPERTY	173	-	173	-	173
TOTAL FLOW THRU DEDUCTIONS	23,302	2,615	25,917	-	25,917
PRETAX INCOME	21,379	(3,950)	17,428	6,369	23,796
<u>SECTION II - NORMALIZED ITEMS</u>					
ADD ADDITIONAL TAXABLE INCOME AND UNALLOWABLE DEDUCTIONS:					
AMORTIZATION -- COMPUTER SOFTWARE	679	(23)	656	-	656
VEHICLE LEASE EXPENSE OVER TAX DEPRECIATION	11	49	60	-	60
INCREASE IN DEFERRED FUEL COST	5,761	(4,434)	1,327	-	1,327
AMORTIZATION OF RATE CASE COST	18	-	18	-	18
AMORTIZATION OF BOND REDEMPTION COSTS	83	-	83	-	83
AMORTIZATION OF RECOVERED MTA TAX	-	-	-	-	-
MEDICARE REIMBURSEMENT	(423)	-	(423)	-	(423)
POST EMPLOYMENT BENEFITS EXPENSE	3,320	72	3,392	-	3,392
DEFERRED STATE INCOME TAX NON DEDUCTIBLE	765	2,522	3,287	-	3,287
CONTRIBUTIONS IN AID OF CONSTRUCTION	685	-	685	-	685
ENVIRONMENTAL RESERVE	21	-	21	-	21
REVENUE SUBJECT TO REFUND	-	-	-	-	-
UNALLOWABLE BOOK PENSION EXPENSE	7,666	(1,213)	6,453	-	6,453
LOW INCOME/ CUSTOMER OUTREACH	-	-	-	-	-
GAS STRANDED COSTS SURCHARGE RECOVERIES	-	-	-	-	-
PROPERTY TAX REFUND - NET 461H	-	-	-	-	-
TOTAL NORMALIZED ADDITIONS	18,586	(3,027)	15,559	-	15,559
DEDUCT NONTAXABLE INCOME AND ADDITIONAL ALLOWABLE DEDUCTIONS:					
TAX DEPRECIATION (NORM) - ADR/ACRS/MACRS	8,934	1,344	10,278	-	10,278
- PROPOSED BOOK RATE	335	(33)	302	-	302
SECTION 263A DEDUCTION (CAPITALIZED OVERHEADS)	6,072	181	6,253	-	6,253
TAX OVER BOOK -- BH LEASE	-	-	-	-	-
PENSION FUNDING	8,348	28,188	36,536	-	36,536
SUPPLEMENTAL PENSION	525	(19)	506	-	506
OPEB FUNDING	2,676	714	3,390	-	3,390
AMORTIZATION OF CONSERVATION COSTS	68	-	68	-	68
LTIP AND STOCK OPTIONS	-	-	-	-	-
RESERVE FOR MEDICAL INSURANCE	-	-	-	-	-
INTEREST -- ALGONQUIN CAPACITY PAYMENT	-	-	-	-	-
MERCHANT FUNCTION CHARGE	-	-	-	-	-
PHASE IN OF RATE RELIEF 05-G-1494	-	-	-	-	-
MTA TAX DEFERRED	-	-	-	-	-
GAS IN STORAGE CARRYING CHARGE	570	-	570	-	570
ENVIRONMENTAL COST - QER EXPEND. SECT. 198	991	-	991	-	991
TOTAL	28,519	30,374	58,893	-	58,893
TAXABLE INCOME OR (LOSS)	11,446	(37,352)	(25,906)	6,369	(19,538)
<u>SUMMARY OF FEDERAL INCOME TAXES</u>					
CURRENT FEDERAL INCOME TAXES	4,006	(13,073)	(9,067)	2,229	(6,838)
DEFERRED FEDERAL INCOME TAXES	3,476	11,691	15,167	-	15,167
AMORTIZATION OF DEFERRED FIT -- 263A	(350)	(54)	(404)	-	(404)
TOTAL CURRENT PERIOD FIT	7,132	(1,436)	5,696	2,229	7,925
PRIOR YEARS (OVER)/UNDER ACCRUAL	-	-	-	-	-
FEDERAL INCOME TAX EXPENSE	7,132	(1,436)	5,696	2,229	7,925
(Incr. (Incr.) / Decr. to Rate Base - Change in Def. FIT - Depr.	5,369	-	5,369	-	5,369
Decrease - Amortization of Deferred FIT - Depr	(350)	(54)	(404)	-	(404)
Net Rate Base (Increase) / Decrease	5,019	(54)	4,965	780	5,745

Orange & Rockland Utilities, Inc.
Gas Department
Federal Income Tax
Twelve Months Ending October 31, 2012
(\$000's)

Exhibit E-7
Schedule 9
Page 2 of 2

	2011 As Reflected in Exhibit G-4 and G-5	2012 Adjustments	2012 As Adjusted	Changes	Adjusted
Operating Income Before Income Taxes	\$37,396	\$ (637)	\$ 36,759	\$3,817	\$40,576
New York State Income Taxes	1,749	(121)	1,629	271	1,900
Book Operating Income before FIT	35,647	(516)	35,131	3,546	38,676
<u>Flow Through Items</u>					
<u>Add: Additional Income and Unallowable Deductions</u>					
BOOK DEPRECIATION - CHARGED TO EXPENSE	11,681	773	12,454	-	12,454
- CHARGED TO CLEARING	2,385	523	2,908	-	2,908
Capitalized Interest	-	-	-	-	-
UNALLOWABLE BUSINESS EXPENSE	-	-	-	-	-
NON TAXABLE INCOME, UNALLOWABLE DEDUCTIONS	-	-	-	-	-
Total Additions	14,066	1,296	15,362	-	15,362
<u>Deduct: Non-Taxable Income and Additional Deductions</u>					
Interest Expense	12,025	1,056	13,081	-	13,081
STATUTORY DEPRECIATION - CURRENT BOOK RATES	12,496	1,055	13,551	-	13,551
- PROPOSED BOOK RATES	(302)	-	(302)	-	(302)
COST OF REMOVAL	681	(468)	214	-	214
MEDICARE REIMBURSEMENT	735	-	735	-	735
LIEN DATE PROPERTY TAX DEDUCTION	109	-	109	-	109
AFUDC	-	-	-	-	-
LOSS ON DISPOSITION OF PROPERTY	173	-	173	-	173
TOTAL FLOW THRU DEDUCTIONS	25,917	1,644	27,561	-	27,561
PRETAX INCOME	23,796	(864)	22,932	3,546	26,477
<u>SECTION II - NORMALIZED ITEMS</u>					
<u>ADD ADDITIONAL TAXABLE INCOME AND UNALLOWABLE DEDUCTIONS:</u>					
AMORTIZATION - COMPUTER SOFTWARE	656	(34)	622	-	622
VEHICLE LEASE EXPENSE OVER TAX DEPRECIATION	60	(69)	(10)	-	(10)
INCREASE IN DEFERRED FUEL COST	1,327	(433)	894	-	894
AMORTIZATION OF RATE CASE COST	18	-	18	-	18
AMORTIZATION OF BOND REDEMPTION COSTS	83	-	83	-	83
AMORTIZATION OF RECOVERED MTA TAX	-	-	-	-	-
MEDICARE REIMBURSEMENT	(423)	-	(423)	-	(423)
POST EMPLOYMENT BENEFITS EXPENSE	3,392	(27)	3,365	-	3,365
DEFERRED STATE INCOME TAX NON DEDUCTIBLE	3,287	(1,056)	2,231	-	2,231
CONTRIBUTIONS IN AID OF CONSTRUCTION	685	-	685	-	685
ENVIRONMENTAL RESERVE	21	-	21	-	21
REVENUE SUBJECT TO REFUND	-	-	-	-	-
UNALLOWABLE BOOK PENSION EXPENSE	6,453	(1,188)	5,265	-	5,265
LOW INCOME/ CUSTOMER OUTREACH	-	-	-	-	-
GAS STRANDED COSTS SURCHARGE RECOVERIES	-	-	-	-	-
PROPERTY TAX REFUND - NET 461H	-	-	-	-	-
TOTAL NORMALIZED ADDITIONS	15,559	(2,807)	12,752	-	12,752
<u>DEDUCT NONTAXABLE INCOME AND ADDITIONAL ALLOWABLE DEDUCTIONS:</u>					
TAX DEPRECIATION (NORM) - ADR/ACRS/MACRS	10,278	1,107	11,385	-	11,385
- PROPOSED BOOK RATE	302	-	302	-	302
SECTION 263A DEDUCTION (CAPITALIZED OVERHEADS)	6,253	(16)	6,237	-	6,237
TAX OVER BOOK - BH LEASE	-	-	-	-	-
PENSION FUNDING	36,536	(17,053)	19,483	-	19,483
SUPPLEMENTAL PENSION	506	(9)	497	-	497
OPEB FUNDING	3,390	22	3,412	-	3,412
AMORTIZATION OF CONSERVATION COSTS	68	-	68	-	68
LTIP AND STOCK OPTIONS	-	-	-	-	-
RESERVE FOR MEDICAL INSURANCE	-	-	-	-	-
INTEREST - ALGONQUIN CAPACITY PAYMENT	-	-	-	-	-
MERCHANT FUNCTION CHARGE	-	-	-	-	-
PHASE IN OF RATE RELIEF 05-G-1494	-	-	-	-	-
MTA TAX DEFERRED	-	-	-	-	-
GAS IN STORAGE CARRYING CHARGE	570	-	570	-	570
ENVIRONMENTAL COST - QER EXPEND. SECT. 198	991	-	991	-	991
TOTAL	58,693	(15,949)	42,944	-	42,944
TAXABLE INCOME OR (LOSS)	(19,538)	12,278	(7,260)	3,546	(3,715)
<u>SUMMARY OF FEDERAL INCOME TAXES</u>					
CURRENT FEDERAL INCOME TAXES	(6,838)	4,297	(2,541)	1,241	(1,300)
DEFERRED FEDERAL INCOME TAXES	15,167	(4,600)	10,567	-	10,567
AMORTIZATION OF DEFERRED FIT - 263A	(404)	(53)	(457)	-	(457)
TOTAL CURRENT PERIOD FIT	7,925	(356)	7,569	1,241	8,810
PRIOR YEARS (OVER)/UNDER ACCRUAL	-	-	-	-	-
FEDERAL INCOME TAX EXPENSE	7,925	(356)	7,569	1,241	8,810

Orange & Rockland Utilities, Inc.
Gas Department
Rate Base
Twelve Months Ending October 31, 2011
(\$000's)

Exhibit G-7
Schedule 10
Page 1 of 4

	2010 As Reflected in <u>Exhibit G-2</u>	2011 <u>Adjustments</u>	2011 <u>As Adjusted</u>
Utility Plant:			
Book Cost of Plant	493,591	\$45,509	\$539,100
Accumulated Reserve for Depreciation	(170,435)	(\$14,581)	(185,016)
Net Plant	<u>323,156</u>	<u>30,928</u>	<u>354,084</u>
Working Capital	12,543	428	12,971
<u>Regulatory Assets / (Liabilities):</u>			
M.T.A. SURTAX - NET OF INCOME TAX	155	-	155
RATE CASE COSTS - NET OF INCOME TAX	32	(13)	19
CUSTOMER OUTREACH PROGRAM - NET OF INCOME TAX	(226)	-	(226)
MGP ENVIRONMENTAL - RY1 Balance	2,584	(1,034)	1,550
- RY2 Balance	-	957	957
- RY3 Balance	-	-	-
CUSTOMER ADVANCES FOR CONSTRUCTION - NET OF INCOME TAX	(40)	-	(40)
GAS PERFORMANCE INCENTIVES - NET OF INCOME TAX	(78)	31	(47)
<u>ACCUM. DEFERRED INCOME TAXES</u>			
ACCUM. DEFERRED FIT - ACRS / ADR	(47,910)	(3,703)	(51,613)
ACCUM. DEFERRED FIT - 263(A) CAPITALIZED OVERHEADS	(12,242)	(1,785)	(14,027)
ACCUM. DEFERRED SIT	(4,757)	(2,522)	(7,279)
ACCUM. FIT ON DEFERRED SIT	1,522	883	2,405
ACCUMULATED DEFERRED INVESTMENT TAX CREDITS	(796)	213	(583)
Rate Base - Total	<u><u>273,943</u></u>	<u><u>\$24,382</u></u>	<u><u>\$298,326</u></u>

Orange & Rockland Utilities, Inc.
Gas Department
Working Capital Allowance
Twelve Months Ending October 31, 2011
(\$000's)

Exhibit G-7
Schedule 10
Page 2 of 4

	2010 As Reflected in <u>Exhibit G-2</u>	2011 <u>Adjustments</u>	2011 <u>As Adjusted</u>
<u>M & S</u>			
GENERAL & COMMON (GAS)	\$1,425	\$30	\$1,455
TOTAL MATERIALS AND SUPPLIES	<u>1,425</u>	<u>30</u>	<u>1,455</u>
<u>PREPAYMENTS</u>			
INSURANCE	28	1	29
PROPERTY TAXES	4,596	270	4,866
PSC ASSESSMENT	230	5	234
OTHER	(201)	(4)	(205)
TOTAL PREPAYMENTS	<u>4,653</u>	<u>271</u>	<u>4,924</u>
<u>CASH WORKING CAPITAL</u>			
OPERATION & MAINTENANCE EXP.	200,655	(1,970)	198,685
LESS:			
PURCHASED GAS	138,403	836	139,239
UNCOLLECTIBLES	1,185	(16)	1,169
<u>REGULATORY ITEMS (DEFERRED CHARGES)</u>			
DEFERRED PURCHASED GAS EXP.	5,761	(4,434)	1,327
PENSION AMORTIZATION	1,084	-	1,084
OPEB AMORTIZATION	530	-	530
OUTREACH & EDUCATION	(150)	-	(150)
RATE CASE COSTS	18	-	18
GAS MAINS AMORTIZATION	300	-	300
MGP	1,803	634	2,437
WORKING CAPITAL REQUIREMENTS	<u>51,721</u>	<u>1,010</u>	<u>52,731</u>
CASH WORKING CAPITAL @ 1/8	<u>6,465</u>	<u>126</u>	<u>6,591</u>
TOTAL WORKING CAPITAL	<u>\$ 12,543</u>	<u>\$ 428</u>	<u>\$ 12,971</u>

Orange & Rockland Utilities, Inc.
Gas Department
Rate Base
Twelve Months Ending October 31, 2012
(\$000's)

Exhibit G-7
Schedule 10
Page 3 of 4

	2011 As Reflected in <u>Exhibit E-6</u>	2012 <u>Adjustments</u>	2012 <u>As Adjusted</u>
Utility Plant:			
Book Cost of Plant	\$539,100	42,564	\$581,664
Accumulated Reserve for Depreciation	(\$185,016)	(15,276)	(200,292)
Net Plant	<u>354,084</u>	<u>27,288</u>	<u>381,372</u>
Working Capital	12,971	1,117	14,088
<u>Regulatory Assets / (Liabilities):</u>			
M.T.A. SURTAX - NET OF INCOME TAX	155	-	155
RATE CASE COSTS - NET OF INCOME TAX	19	(13)	6
CUSTOMER OUTREACH PROGRAM - NET OF INCOME TAX	(226)	-	(226)
MGP ENVIRONMENTAL - RY1 Balance	1,550	(1,034)	516
- RY2 Balance	957	(383)	574
- RY3 Balance	-	589	589
CUSTOMER ADVANCES FOR CONSTRUCTION - NET OF INCOME TAX	(40)	-	(40)
GAS PERFORMANCE INCENTIVES - NET OF INCOME TAX	(47)	31	(16)
<u>ACCUM. DEFERRED INCOME TAXES</u>			
ACCUM. DEFERRED FIT - ACRS / ADR	(51,613)	(4,091)	(55,704)
ACCUM. DEFERRED FIT - 263(A) CAPITALIZED OVERHEADS	(14,027)	(2,640)	(16,667)
ACCUM. DEFERRED SIT	(7,279)	(2,231)	(9,510)
ACCUM. FIT ON DEFERRED SIT	2,405	780	3,185
ACCUMULATED DEFERRED INVESTMENT TAX CREDITS	(583)	213	(370)
Rate Base - Total	<u>298,326</u>	<u>19,626</u>	<u>317,952</u>
0			

Orange & Rockland Utilities, Inc.
Gas Department
Working Capital Allowance
Twelve Months Ending October 31, 2012
(\$000's)

Exhibit G-7
Schedule 10
Page 4 of 4

	2011 As Reflected in <u>Exhibit G-6</u>	2012 <u>Adjustments</u>	2012 <u>As Adjusted</u>
<u>M & S</u>			
GENERAL & COMMON (GAS)	\$1,455	\$31	\$1,486
TOTAL MATERIALS AND SUPPLIES	<u>1,455</u>	<u>31</u>	<u>1,486</u>
 <u>PREPAYMENTS</u>			
INSURANCE	29	1	30
PROPERTY TAXES	4,866	271	5,137
PSC ASSESSMENT	234	5	239
OTHER	(205)	(4)	(210)
TOTAL PREPAYMENTS	<u>4,924</u>	<u>272</u>	<u>5,196</u>
 <u>CASH WORKING CAPITAL</u>			
OPERATION & MAINTENANCE EXP.	198,685	12,144	210,828
 LESS:			
PURCHASED GAS	139,239	5,671	144,910
UNCOLLECTIBLES	1,169	-	1,169
 REGULATORY ITEMS (DEFERRED CHARGES)			
DEFERRED PURCHASED GAS EXP.	1,327	(433)	894
PENSION AMORTIZATION	1,084	-	1,084
OPEB AMORTIZATION	530	-	530
OUTREACH & EDUCATION	(150)	-	-
RATE CASE COSTS	18	-	18
GAS MAINS AMORTIZATION	300	-	300
MGP	2,437	390	2,827
WORKING CAPITAL REQUIREMENTS	<u>52,731</u>	<u>6,516</u>	<u>59,096</u>
 CASH WORKING CAPITAL @ 1/8	<u>6,591</u>	<u>814</u>	<u>7,406</u>
 TOTAL WORKING CAPITAL	<u>\$ 12,971</u>	<u>\$ 1,117</u>	<u>\$ 14,088</u>

Orange & Rockland Utilities, Inc.
Gas Department
Interest Synchronization
Twelve Months Ending October 31, 2011
(\$000's)

	2010 As Reflected in <u>Exhibit G-4 and G-5</u>	2011 <u>Adjustments</u>	2011 <u>As Adjusted</u>
Rate Base	\$261,760	\$24,382	\$286,143
Interest Bearing CWIP (+)	<u>5,687</u>	<u>-</u>	<u>5,687</u>
Earnings Base	267,447	24,382	291,830
Embedded Cost of Debt	<u>3.91%</u>		<u>4.12%</u>
Interest Deduction	<u>\$10,460</u>	<u>\$1,565</u>	<u>\$12,025</u>

Twelve Months Ending October 31, 2012
(\$000's)

	2011 As Reflected in <u>Exhibit G-6</u>	2012 <u>Adjustments</u>	2012 <u>As Adjusted</u>
Rate Base	\$286,143	\$19,626	\$305,769
Interest Bearing CWIP (+)	<u>5,687</u>	<u>-</u>	<u>5,687</u>
Earnings Base	291,830	19,626	311,456
Embedded Cost of Debt	<u>4.12%</u>		<u>4.20%</u>
Interest Deduction	<u>\$12,025</u>	<u>\$1,056</u>	<u>\$13,081</u>

ORANGE AND ROCKLAND UTILITIES, INC.

INDEX OF SCHEDULES

Cost of Capital

<u>SCHEDULE</u>	<u>TITLE OF SCHEDULE</u>	<u>WITNESS</u>
1	Forecasted Consolidated Capitalization and Cost Rates	J. Perkins
2	Long-Term Debt	"
3	Equity as Percent of Capital - New York vs. Other States	"
4	Return on Equity - New York vs. Other States	"

ORANGE AND ROCKLAND UTILITIES, INC. & SUBSIDIARIES
FORECASTED CONSOLIDATED CAPITALIZATION AND COST RATES

Exhibit G-8
Schedule 1
Pg. 1 of 3

Forecasted for the Thirteen Month Average Ended
October 31, 2010

	13 Month Average October 31, 2010	Calculated %	Adjusted %	Cost Rate	Weighted Cost
Long term Debt					
ORU	529,344,622				
RECO	0				
Pike	3,200,000				
Total	<u>532,544,622</u>	48.38%	50.61%	7.62%	3.86%
Customer Deposits					
ORU	12,357,000				
RECO	2,089,000				
Pike	140,000				
Total	<u>14,586,000</u>	1.33%	1.39%	3.92%	0.05%
Common Equity					
Par	5,000				
Premium	322,805,100				
Expense	(149,900)				
Retained Earnings	230,904,000				
Total	<u>553,564,200</u>	50.29%	48.00%	11.60%	5.57%
Total Capitalization	<u>1,100,694,822</u>	<u>100.00%</u>			<u>9.48%</u>

ORANGE AND ROCKLAND UTILITIES, INC. & SUBSIDIARIES
FORECASTED CONSOLIDATED CAPITALIZATION AND COST RATES

Exhibit G-8
Schedule 1
Page 2 of 3

Forecasted for the Thirteen Month Average Ended
October 31, 2011

	<u>13 Month Average October 31, 2011</u>	<u>Calculated %</u>	<u>Adjusted %</u>	<u>Cost Rate</u>	<u>Weighted Cost</u>
Long term Debt					
ORU	604,416,500				
RECO	0				
Pike	3,200,000				
Total	<u>607,616,500</u>	49.23%	50.78%	8.02%	4.07%
Customer Deposits					
ORU	12,357,000				
RECO	2,089,000				
Pike	140,000				
Total	<u>14,586,000</u>	1.18%	1.22%	3.92%	0.05%
Common Equity					
Par	5,000				
Premium	345,305,100				
Expense	(149,900)				
Retained Earnings	266,973,000				
Total	<u>612,133,200</u>	49.59%	48.00%	11.60%	5.57%
Total Capitalization	<u>1,234,335,700</u>	<u>100.00%</u>			<u>9.69%</u>

ORANGE AND ROCKLAND UTILITIES, INC. & SUBSIDIARIES
FORECASTED CONSOLIDATED CAPITALIZATION AND COST RATES

Exhibit G-8
Schedule 1
Pg. 3 of 3

Forecasted for the Thirteen Month Average Ended
October 31, 2012

	13 Month Average October 31, 2012	Calculated %	Adjusted %	Cost Rate	Weighted Cost
Long term Debt					
ORU	646,970,218				
RECO	0				
Pike	3,200,000				
Total	650,170,218	47.42%	50.86%	8.17%	4.16%
Customer Deposits					
ORU	12,357,000				
RECO	2,089,000				
Pike	140,000				
Total	14,586,000	1.06%	1.14%	3.92%	0.04%
Common Equity					
Par	5,000				
Premium	394,055,100				
Expense	(149,900)				
Retained Earnings	312,565,000				
Total	706,475,200	51.52%	48.00%	11.60%	5.57%
Total Capitalization	1,371,231,418	100.00%			9.77%

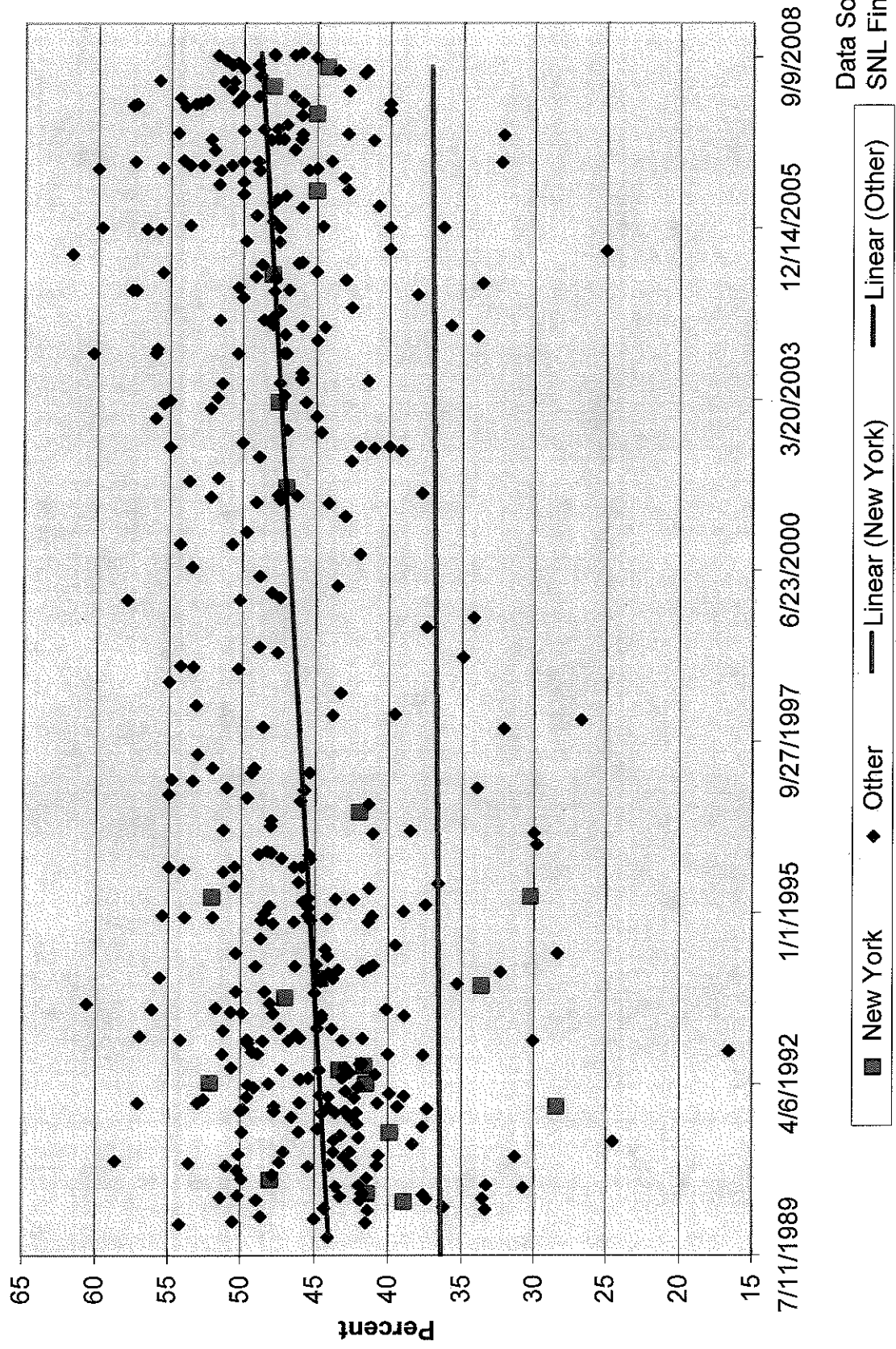
ORANGE AND ROCKLAND UTILITIES, INC. AND SUBSIDIARIES
LONG TERM DEBT
Actual At June 30 2008

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
Debtentures:									
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%	3/31/05	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
			<u>285,000,000</u>					<u>6.53%</u>	<u>19,256,500</u>
Pollution Control Debt:									
1994, 6.09%	10/1/94	10/1/14	6,020,000	55,000,000	0	4,544,524	50,455,476	6.85%	412,370
1995, Variable Rate	8/1/95	8/1/15	43,200,000	44,000,000	0	3,571,683	40,428,317	5.05%	2,185,920
			<u>49,220,000</u>					<u>5.28%</u>	<u>2,598,290</u>
Sub Total ORU Debt			344,220,000					6.35%	21,854,790
Unamortized Debt Discount			(826,285)						
Total ORU			<u>343,393,715</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			347,420,000						
Long Term Debt			(826,285)						
Unamortized Debt Discount			<u>346,593,715</u>						
Total Consolidated								<u>6.36%</u>	<u>22,109,830</u>

ORANGE AND ROCKLAND UTILITIES, INC. AND SUBSIDIARIES
LONG TERM DEBT
Forecast - Thirteen Months Ended October 31, 2010

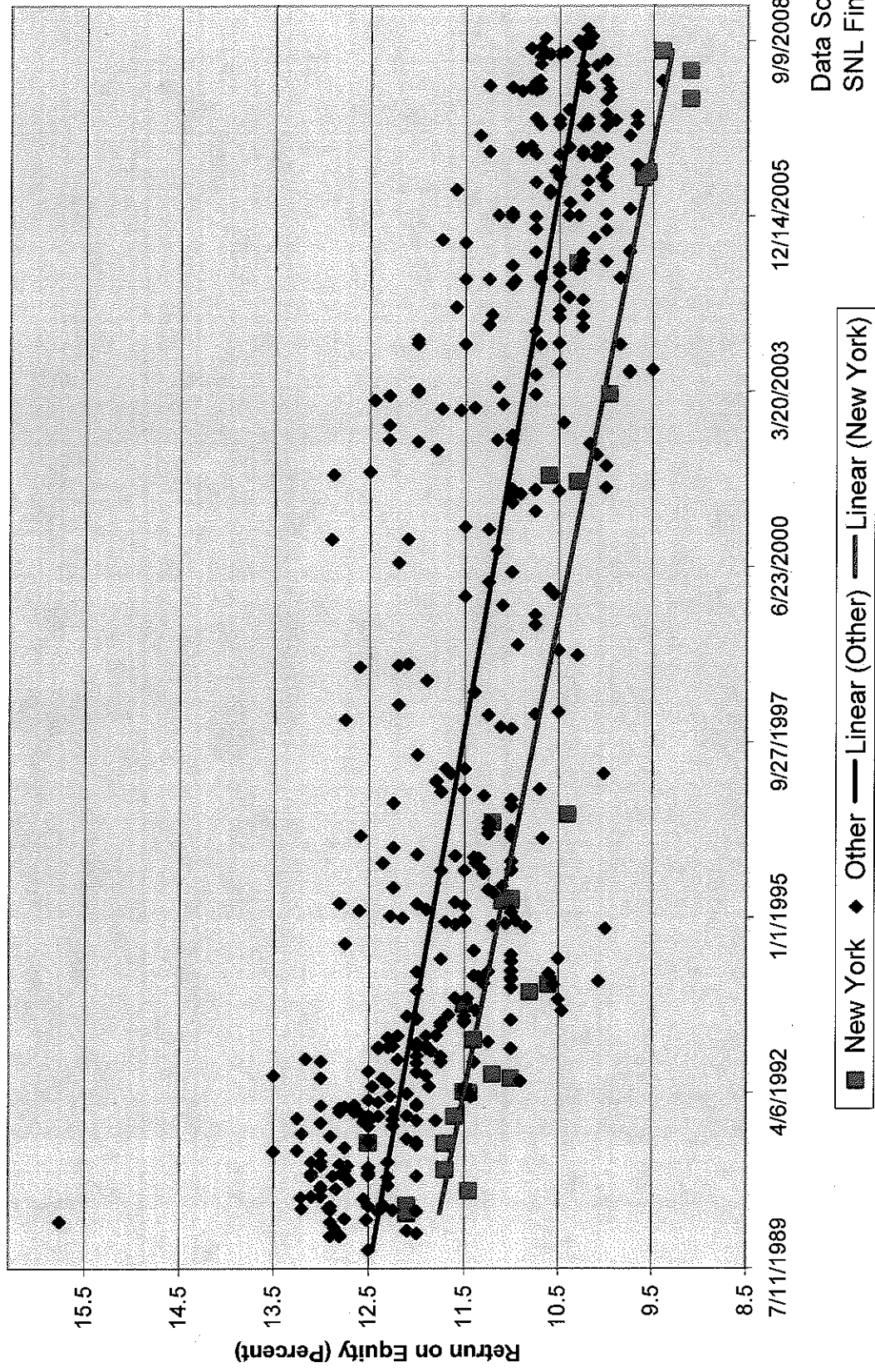
Orange and Rockland Utilities, Inc.	Issue Date	Maturity Date	Amount Outstanding (13 Mos Avg)	Original Issue Amount	Premium or Discount	Expense of Issuance	Net Proceeds	Actual Cost of Money	Effective Annual Cost
Debtentures:									
Series F, 6.50%	12/18/97	12/1/27	80,000,000	80,000,000	0	901,750	79,098,250	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	34,375,000	55,000,000	(925,700)	204,220	53,870,080	7.80%	2,681,250
Series A, 2005, 5.30%	3/31/05	4/1/15	40,000,000	40,000,000	(80,000)	495,000	39,425,000	5.48%	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, 6.15%	9/1/08	9/1/18	50,000,000	50,000,000	(89,500)	625,000	49,285,500	6.34%	3,170,000
Series A, 2009, 9.03%	3/1/09	3/1/19	100,000,000	100,000,000	0	1,150,000	98,850,000	9.21%	9,210,000
Series B, 2009, 9.65%	9/1/09	9/1/39	75,000,000	75,000,000	0	1,156,250	73,843,750	9.81%	7,357,500
Series A, 2010, 9.38%	6/1/10	6/1/20	20,625,000	55,000,000	0	875,500	54,124,500	9.63%	1,986,188
Series B, 2010, 9.90%	9/1/10	9/1/40	10,000,000	80,000,000	0	1,200,000	78,800,000	10.06%	1,006,000
			<u>530,000,000</u>					<u>7.62%</u>	<u>40,377,438</u>
Pollution Control Debt:									
1994, 6.09%	10/1/94	10/1/14	0	0	0	0	0	6.85%	0
1995, Variable Rate	8/1/95	8/1/15	0	0	0	0	0	5.06%	0
			<u>0</u>						<u>0</u>
Sub Total ORU Debt			530,000,000					7.62%	40,377,438
Unamortized Debt Discount			(655,378)						
Total ORU			<u>529,344,622</u>						
Pike County Light & Power Company									
First Mortgage Bonds:									
Series C, 7.07%	11/10/88	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			533,200,000					7.62%	40,632,478
Long Term Debt			(655,378)						
Unamortized Debt Discount			<u>532,544,622</u>						
Total Consolidated									

Equity as Percent of Capital-New York vs. Other States



Return on Equity-New York vs. Other States

Exhibit (G-8)
Schedule 4



ORANGE AND ROCKLAND UTILITIES, INC.

INDEX OF SCHEDULES

Gas Supply

<u>SCHEDULE</u>	<u>TITLE OF SCHEDULE</u>	<u>WITNESS</u>
1	Gas Supply Contracts	P. Olmsted
2	Pipeline Transportation Contracts	"
3	Storage Contracts	"
4	Peaking Supplies	"
5	Peak Day Forecasted Requirements	"
6	Production Area Storage	"
7	Non Traditional Revenues	"
8	FERC Docket Interventions	"
9	Summer Season Supply/Demand Balance	"
10	Winter Season Supply/Demand Balance	"
11	Peak Day Supply / Demand Balance	"
12	Natural Gas Marginal Monthly Commodity Costs	"
13	Marginal Commodity/Capacity Costs (\$/Dth)	"
14	Ratio of Full Service Customers to All Customers	"

Gas Supply Contracts
Combined ConEdison and Orange & Rockland

<u>Firm Gas Supplier</u>	<u>Expiration Date</u>	<u>Total MDT</u>
<u>ALGONQUIN</u>		
Contract 1	03/31/09	1,000
Contract 2	03/31/09	3,100
Contract 3	02/28/09	20,000
<u>COLUMBIA GAS</u>		
Contract 4	03/31/12	2,200
Contract 5	10/31/09	2,700
Contract 6	10/31/10	5,000
Contract 7	10/31/10	5,000
Contract 8	03/31/13	1,900
<u>DOMINION</u>		
Contract 9	03/31/12	7,575
<u>IROQUOIS</u>		
Contract 10	10/31/11	11,128
Contract 11	10/31/11	9,106
<u>National Fuel</u>		
Contract 12	10/31/13	20,000
Contract 13	03/31/09	10,000
Contract 14	03/31/09	17,000
Contract 15	03/31/09	20,000
<u>TENNESSEE</u>		
Contract 16	10/31/09	30,000
Contract 17	10/31/09	5,000
Contract 18	10/31/09	5,000
Contract 19	03/31/09	4,000
Contract 20	03/31/09	9,000
Contract 21	03/31/10	10,000
Contract 22	10/31/10	10,000
Contract 23	10/31/10	4,000
Contract 24	03/31/12	3,600
<u>TETCO</u>		
Contract 25	03/31/09	3,000
Contract 26	10/31/09	5,600
Contract 27	03/31/09	12,000
Contract 28	10/31/09	15,000
Contract 29	03/31/10	7,000
Contract 30	03/31/09	2,600
Contract 31	10/31/09	1,800
Contract 32	10/31/13	3,200
<u>TRANSCO</u>		
Contract 33	03/31/09	3,000
Contract 34	10/31/10	10,000
Contract 35	10/31/11	5,000
Contract 36	10/31/09	37,000
Contract 37	10/31/11	23,000
Contract 38	03/31/12	6,000
Contract 39	03/31/12	6,000
Contract 40	10/31/09	4,200
Contract 41	10/31/13	5,000
Total:		365,709

Pipeline Transportation Contracts
Combined Con Edison and Orange & Rockland FT (MdtH/day)

<u>Pipeline</u>	<u>Rate Schedule</u>	<u>Contract Number</u>	<u>Upstream MDQ</u>	<u>City-Gate MDQ</u>	<u>Expiration Date</u>
Iroquois	RTS12	560-01		20,234	1/25/2012
	RTS12	560-16		32,998	10/31/2018
Columbia	FTS	100384		51,918	3/31/2019
	FTS	100383		2,742	10/31/2009
	FTS	3796	19,186		3/31/2019
Algonquin	AFT-EW	9W005EC		6,676	9/30/2009
	AFT-11	93010C		5,470	10/31/2012
	AFT-14	93406		246	10/31/2012
	AFT-1Z	86013		225	4/30/2007
	T-1	931003		5,292	8/1/2009
	AFT-1	97033			10/31/2009
	FT-1	510371R2	125,000		10/31/2018
Transco	FT	1002239		2,084	Evergreen
	FT	100659		3,769	Evergreen
	FT	100658		4,464	Evergreen
	FT	1016007		30,344	10/30/2016
	FT	1003683		335,880	3/31/2010
	FT-PS	100511		10,143	3/31/2010
Tennessee	FT-A	31585		5,035	11/30/2013
	FT-A	2185		31,212	10/31/2014
	FT-A	330		25,000	10/31/2013
	FT-A	2511/2530/3908/3910	11,630		10/31/2014
	FT-A	8402	12,440		10/31/2013
	FT-A	36656	10,000		4/2/2013
	FT-A				
Tetco	CDS	800410		55,238	10/31/2009
	FT-1	800410		10,000	10/31/2009
	FTS	330836		3,035	10/31/2009
	FT-1	910226		14,770	10/31/2012
	CDSA	800437	384		10/31/2012
	FT-1	800403	10,836		10/31/2012
	CDS	800438	507		10/31/2012
	CDS	400514	507		10/31/2012
	SS-1	400216	1,140		4/30/2013
National Fuel	EFT	E00522	3,800		Evergreen
	EFT	F01775	31,212		Evergreen
	EFT	N11192/F11185	75,000		10/31/2023
Dominion	FT	200398	7,575		10/31/2011
Millenium	FT	FT01-0001	180,000		10/31/2023

Storage Contracts

Combined ConEdison and Orange and Rockland

Market Area Storage	<u>Max Daily Withdrawal</u>	<u>Max Storage Capacity</u>	<u>Expiration Date</u>
Transco SS2	19,355 Dth/d	2,129 Mdth/d	3/31/2009
Transco GSS	10,040 Dth/d	515 Mdth/d	3/31/2009
Dominion/GSSTE	23,115 Dth/d	2,409 Mdth/d	10/31/2011
Telco SS1	69,150 Dth/d	4,169 Mdth/d	10/31/2009
Telco SS1	507 Dth/d	100 Mdth/d	4/30/2013
Telco FSS1	1,140 Dth/d	30 Mdth/d	4/30/2013
Tenn FSMA	84,795 Dth/d	6,664 Mdth/d	10/31/2013
Honeoye	6,834 Dth/d	1,226 Mdth/d	3/31/2009
Stagecoach FT-A	25,000 Dth/d	760 Mdth/d	12/31/2011
Stagecoach FT-A	15,000 Dth/d	456 Mdth/d	12/31/2011
Stagecoach FT-A	25,000 Dth/d	760 Mdth/d	12/31/2011
Stagecoach FT-A	105,000 Dth/d	4,200 Mdth/d	3/31/2018
National Fuel	7,871 Dth/d	589 Mdth/d	10/31/2018
Columbia FSS	20,000 Dth/d	1,432 Mdth/d	3/31/2019
National Grid - LNG	20,000 Dth/d	500 Mdth/d	10/31/2018

Production Area Storage

Transco ESS	52,000 Dth/d	527 Mdth/d	3/31/2009
Transco ESS	90,050 Dth/d	826 Mdth/d	3/23/2010
Transco WSS	145,000 Dth/d	12,339 Mdth/d	3/31/2009
Hattisburg	37,200 Dth/d	372 Mdth/d	3/31/2009

Peaking Supplies
Combined Con Edison and Orange & Rockland (Dth's/day)

	<u>Contract Expiration</u>	<u>Con Edison Peaking Supply Dth's/d</u>	<u>O&R Peaking Supply Dth's/d</u>	<u>Total</u>
LNG ⁽¹⁾	N/A	166,000	N/A	166,000
Propane ⁽²⁾	N/A	N/A	8,000	8,000
Peaking A	3/31/09	20,000	0	20,000
Peaking B ⁽³⁾	3/31/09	10,000	0	10,000
Peaking D ⁽³⁾	3/31/09	27,000	0	27,000
Peaking E ⁽³⁾	3/31/09	27,000	0	27,000
Total		250,000	8,000	258,000

Notes:

(1) The LNG facility is within the Con Edison distribution system located in Astoria, New York.

(2) The Propane facility is within the Orange & Rockland distribution system located in Middletown, New York.

(3) Millenium Pipeline Contingency Supplies.

EXHIBIT _____ (G-9)
Schedule 5

Consolidated Edison/O&R Peak Day Forecasted
Requirements
Peak Day MDT/d

<u>Winter</u>	<u>Consolidated Edison</u>	<u>Orange & Rockland</u>	<u>Total</u>
2008/09	1,108	224	1,332
2009/10	1,137	228	1,365
2010/11	1,156	228	1,384

Production Area Storage
Combined Con Edison and Orange & Rockland
September 2005 - September 2008

	<u>Hurricane</u>	<u>Date</u>	<u>No. of Days</u>	<u>Volume *</u>	<u>Production Storage Facility</u>
1	Hurricane Rita	Sep-05	8	525,000 Dth 10,000 Dth	Transco WSS Hattiesburg
2	Hurricane Dean	Aug-07	11	25,917 Dth	Transco ESS
3	Hurricane Dolly	Jul-08	6	31,140 Dth	Hattiesburg
4	Hurricane Gustav	Aug-08	11	36,330 Dth	Hattiesburg
		Total	36	628,387 Dth	

* Note: This is the volume of gas withdrawn and/or diverted per storage field to meet the market requirement.

Non Traditional Revenues

Combined ConEdison and Orange and Rockland

	Actual 2005/06 <u>Nov - Oct</u>	Actual 2006/07 <u>Nov - Oct</u>	Actual 2007/08 <u>Nov - Oct</u>	Forecast Rate Year 2008/09 <u>Nov - Oct</u>	Forecast Rate Year 2009/10 <u>Nov - Oct</u>
Off System Transactions	(\$45,963.60)	\$718,046	\$26,107	\$0	\$0
Capacity Release	<u>\$19,260,807</u>	<u>\$19,498,665</u>	<u>\$4,411,790</u>	<u>\$5,677</u>	<u>\$5,677</u>
TOTAL	\$19,214,843	\$20,216,711	\$4,437,897	\$5,677	\$5,677
CECONY	\$15,181,648	\$15,973,223	\$3,506,382	\$4,485	\$4,485
ORU	\$4,033,196	\$4,243,488	\$931,515	\$1,191	\$1,191

FERC DOCKET INTERVENTIONS

Algonquin – CP

Docket	Date
CP07-21-000	11/27/2006
CP08-256-000	6/3/2008
CP08-420-000	7/11/2008
CP08-462-000	9/16/2008

Algonquin – RP

Docket	Date
RP06-52-000	11/2/2005
RP06-67-000	11/14/2005
RP06-69-000	11/14/2005
RP06-75-000	11/14/2005
RP06-114-000	12/12/2005
RP06-325-000	5/8/2006
RP06-519-000	9/6/2006
RP07-131-000	10/18/2006
RP07-32-000	11/2/2006
RP07-66-000	11/27/2006
RP07-139-000	1/31/2007
RP07-395-000	4/30/2007
RP07-459-000	6/4/2007
RP07-553-000	8/14/2007
RP07-557-000	8/14/2007
RP07-504-000	9/24/2007
RP08-35-000	11/7/2007
RP08-212-000	3/10/2008
RP08-268-000	3/19/2008
RP08-474-000	8/12/2008

Columbia Gas - CP

Docket	Date
CP98-151-003	1/17/2006
CP06-80-000	3/30/2006
CP98-151-004	5/30/2006
CP06-430-000	8/24/2006
CP06-435-000	9/28/2006
CP06-440-000	9/28/2006
CP06-466-000	10/26/2006
CP07-23-000	11/30/2006
CP07-39-000	1/10/2007
CP07-93-000	3/28/2007
CP07-104-000	5/21/2007
CP07-367-000	6/6/2007
CP07-388-000	8/3/2007
CP07-419-000	8/10/2007
CP07-433-000	9/4/2007
CP07-367-001	11/16/2007
CP08-19-000	11/16/2007
CP08-78-000	3/24/2008
CP08-84-000	3/27/2008
CP08-85-000	4/3/2008
CP08-431-000	8/1/2008

Columbia Gas - RP

Docket	Date
RP06-46-000	11/2/2005
RP06-166-000	1/11/2006
RP06-181-000	2/6/2006
RP06-194-000	2/13/2006
RP06-208-000	2/13/2006
RP06-231-000	3/1/2006
RP06-259-000	3/13/2006
RP06-260-000	3/13/2006
RP06-262-000	3/13/2006
RP06-311-000	4/27/2006
RP06-231-002	6/5/2006
RP06-365-000	6/5/2006
RP06-579-000	9/13/2006
RP06-594-000	9/26/2006
RP07-107-000	12/26/2006
RP07-129-000	1/24/2007
RP07-171-000	2/27/2007
RP07-307-000	3/7/2007
RP07-334-000	3/13/2007
RP07-335-000	3/13/2007
RP07-336-000	3/13/2007
RP07-337-000	3/13/2007
RP07-340-000	3/19/2007
RP07-349-000	3/26/2007
RP07-350-000	3/26/2007
RP07-351-000	3/26/2007
RP07-362-000	4/9/2007
RP07-363-000	4/9/2007
RP06-365-002	4/16/2007
RP06-231-003	4/30/2007
RP06-365-001	4/30/2007
RP07-413-000	5/9/2007
RP07-414-000	5/11/2007
RP07-449-000	5/29/2007
RP07-479-000	6/18/2007
RP07-488-000	6/25/2007
RP07-507-000	7/11/2007
RP07-509-000	7/11/2007
RP07-518-000	7/16/2007
RP07-655-000	9/12/2007
RP08-38-000	11/13/2007
RP08-59-000	11/19/2007
RP08-110-000	12/19/2007
RP08-127-000	12/31/2007
RP08-150-000	1/14/2008
RP08-161-000	1/23/2008

RP08-204-000	3/3/2008
RP08-222-000	3/10/2008
RP08-244-000	3/12/2008
RP08-246-000	3/12/2008
RP06-231-005	4/7/2008
RP06-365-003	4/7/2008
RP08-295-000	4/11/2008
RP08-317-000	4/28/2008
RP06-231-006	4/29/2008
RP06-365-004	4/29/2008
RP08-328-000	5/12/2008
RP08-401-000	6/17/2008
RP08-403-000	6/20/2008
RP08-451-000	7/29/2008
RP08-473-000	8/12/2008
RP08-529-000	9/8/2008
RP08-614-000	9/22/2008

Columbia Gulf – CP

Docket	Date
CP06-413-000	7/14/2006
CP08-26-000	1/22/2008
CP08-54-000	2/19/2008
CP08-91-000	4/10/2008
CP08-119-000	4/15/2008
CP08-399-000	6/3/2008
CP08-406-000	6/5/2008
CP08-149-000	6/20/2008
CP08-464-000	9/11/2008

Columbia Gulf – RP

Docket	Date
RP06-49-000	11/7/2005
RP06-145-000	12/27/2005
RP06-148-000	12/27/2005
RP06-165-000	1/11/2006
RP06-210-000	2/15/2006
RP06-261-000	3/13/2006
RP06-596-000	9/29/2006
RP07-125-000	1/10/2007
RP07-119-000	1/24/2007
RP04-98-002	1/26/2007
RP07-172-000	2/27/2007
RP07-174-000	2/28/2007
RP07-348-000	3/26/2007
RP07-412-000	5/9/2007
RP07-415-000	5/11/2007
RP07-478-000	6/18/2007
RP07-500-000	7/11/2007
RP07-508-000	7/11/2007
RP07-657-000	9/12/2007
RP08-12-000	10/15/2007
RP08-117-000	12/26/2007
RP08-124-000	12/31/2007
RP08-151-000	1/14/2008
RP08-160-000	1/23/2008
RP08-193-000	2/19/2008
RP08-266-000	3/19/2008
RP08-305-000	4/11/2008
RP08-347-000	5/12/2008
RP08-530-000	9/8/2008

Tennessee – CP

Docket	Date
CP06-18-000	12/1/2005
CP06-31-000	1/3/2006
CP06-33-000	1/3/2006
CP06-82-000	3/30/2006
CP05-100-000	9/11/2006
CP08-11-000	11/19/2007
CP08-27-000	12/18/2007
CP08-55-000	2/19/2008
CP08-63-000	2/26/2008
CP08-65-000	3/3/2008
CP08-86-000	3/17/2008
CP08-67-000	4/7/2008
CP08-165-000	5/23/2008
CP08-164-000	7/7/2008
CP08-400-000	7/21/2008
CP08-435-000	8/5/2008

Tennessee – RP

Docket	Date
RP06-125-000	12/13/2005
RP06-157-000	1/10/2006
RP06-219-000	2/22/2006
RP06-289-000	4/12/2006
RP06-297-000	4/27/2006
RP04-99-002	9/13/2006
RP07-89-000	12/8/2006
RP07-151-000	2/12/2007
RP07-375-000	4/11/2007
RP07-396-000	4/23/2007
RP07-396-001	6/4/2007
RP96-312-167	9/19/2007
RP08-222-000	10/22/2007
RP08-101-000	12/10/2007
RP08-234-000	3/12/2008
RP08-338-000	5/12/2008
RP91-203-076	10/14/2008
RP92-132-064	10/14/2008

Texas Eastern – CP

Docket	Date
CP06-115-000	5/30/2006
CP07-20-000	11/27/2006
CP07-411-000	8/1/2007
CP06-115-003	11/7/2007
CP05-392-001	11/21/2007
CP08-75-000	4/11/2008
CP08-120-000	5/8/2008
CP08-88-000	5/12/2008
CP08-111-000	6/9/2008
CP08-461-000	9/19/2008

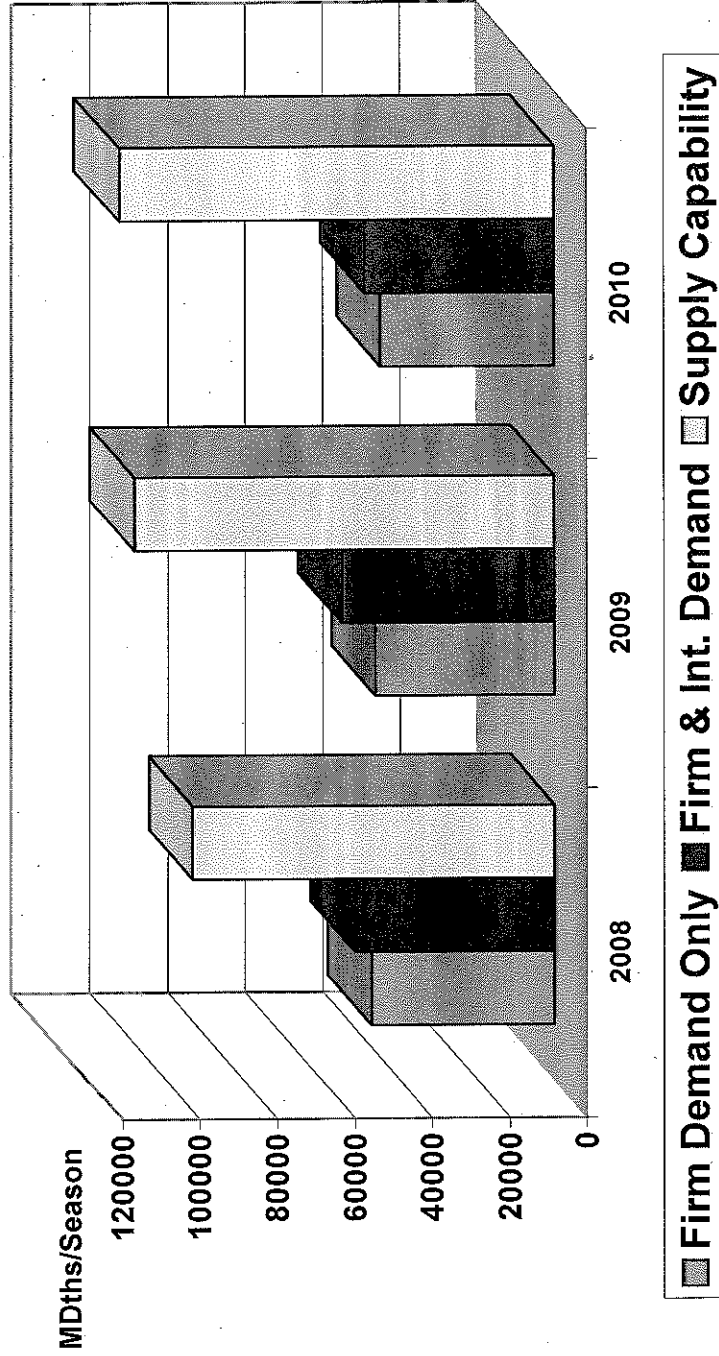
Texas Eastern – RP

Docket	Date
RP06-45-000	11/2/2005
RP88-67-081	11/2/2005
RP98-198-008	11/2/2005
RP06-70-000	11/14/2005
RP06-113-000	12/12/2005
RP06-167-000	1/11/2006
RP06-306-000	4/24/2006
RP06-323-000	5/8/2006
RP06-379-000	6/14/2006
RP06-465-000	8/9/2006
RP06-588-000	9/13/2006
RP07-8-000	10/18/2006
RP07-20-000	10/30/2006
RP07-27-000	10/30/2006
RP07-67-000	11/27/2006
RP07-127-000	1/10/2007
RP07-460-000	6/4/2007
RP07-502-000	7/14/2007
RP07-550-000	8/14/2007
RP07-552-000	8/14/2007
RP07-590-000	8/28/2007
RP07-650-000	9/12/2007
RP07-693-000	9/26/2007
RP08-14-000	10/15/2007
RP08-33-000	11/7/2007
RP99-480-018	11/13/2007
RP08-62-000	11/21/2007
RP08-73-000	12/10/2007
RP08-80-000	12/10/2007
RP08-133-000	1/4/2008
RP08-148-000	1/14/2008
RP08-185-000	2/13/2008
RP08-216-000	3/10/2008
RP08-267-000	3/19/2008
RP08-399-000	6/16/2008
RP08-434-000	7/14/2008
RP08-476-000	8/12/2008
RP08-605-000	9/15/2008

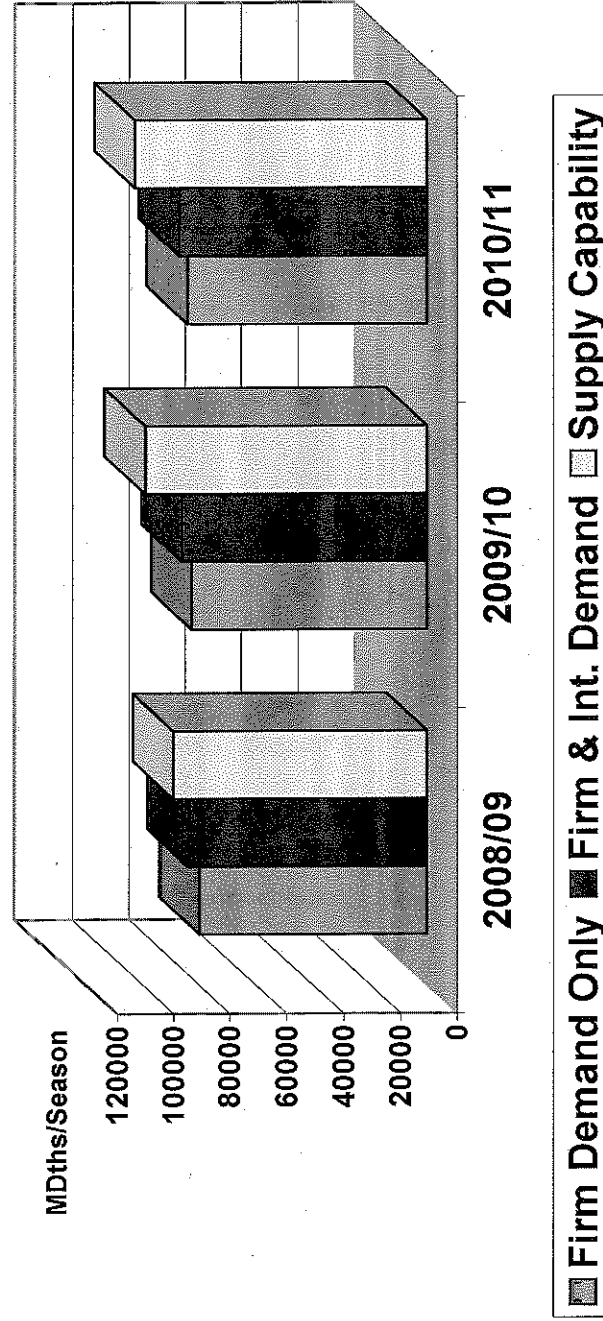
Miscellaneous – CP, RP, RM

Docket	Date	Party
CP06-64-000	3/10/2006	Central New York Oil & Gas
CP06-64-001	5/30/2006	Central New York Oil & Gas
CP98-150-006	6/5/2006	Millennium
RP06-391-000	6/30/2006	US Gen New England
CP06-354-000	7/18/2006	Rockies Express
RM06-7-000	8/25/2006	FERC Rulemaking or NOPR
RP08-46-000	11/13/2007	Distrigas of Massachusetts
RP08-374-000	5/27/2008	Maritimes & Northeast

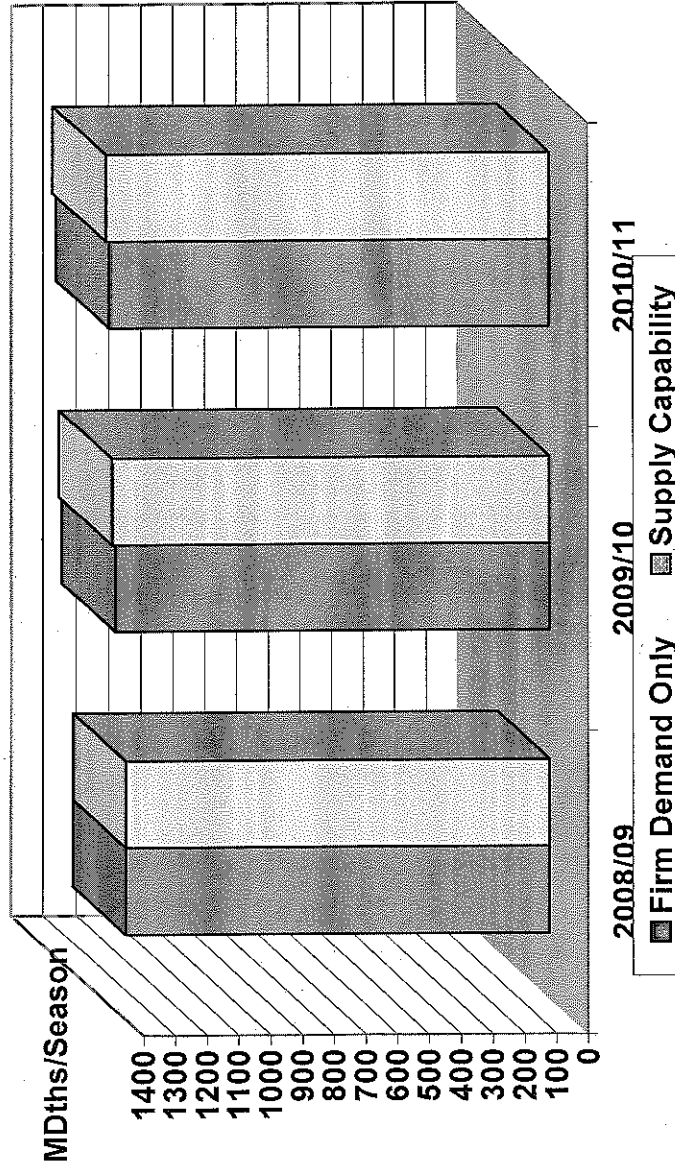
**Combined Consolidated Edison Company of New
York, Inc./Orange & Rockland, Inc.
Summer Season Supply/Demand Balance**



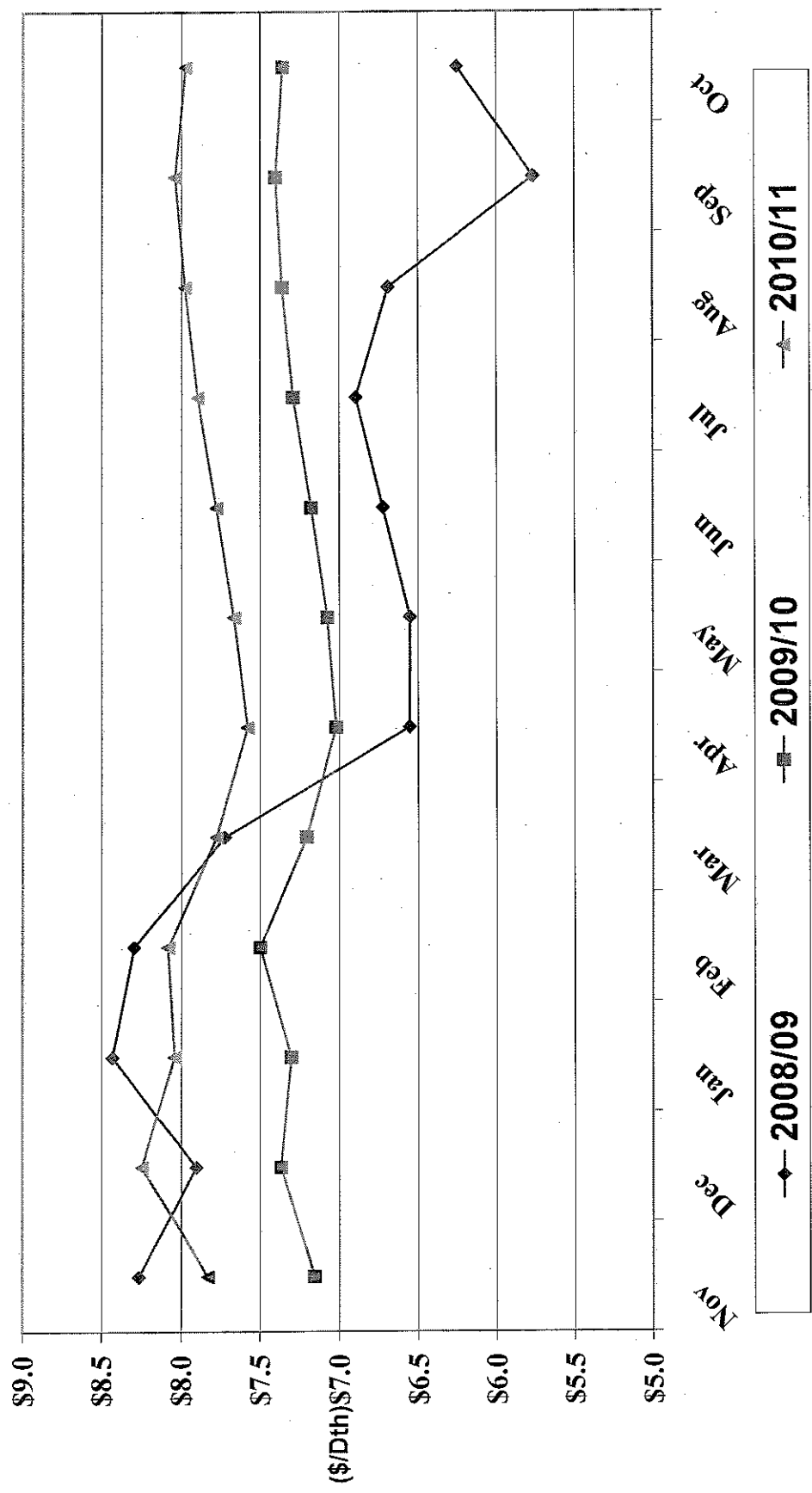
**Combined Consolidated Edison Company of New York,
Inc./Orange & Rockland, Inc.
Winter Season Supply/Demand Balance**



**Combined Consolidated Edison Company of New
York, Inc./Orange & Rockland, Inc.
Peak Day Supply/Demand Balance**



**Combined Consolidated Edison Company of New
York, Inc./Orange & Rockland, Inc.
Natural Gas Marginal Monthly Commodity Costs**



Combined Consolidated Edison of New York,
Inc./Orange & Rockland, Inc.

Marginal Commodity/Capacity Costs (\$/Dth)

Gas Year	Average Annual (commodity)	Average Summer (commodity)	Average Winter (commodity)	Peak Day (commodity)	Marginal Capacity Cost (3)
2008/09	\$7.17	\$6.49	\$8.12	\$18.40	\$6.17
2009/10	\$7.27	\$7.24	\$7.30	\$18.90	\$6.81
2010/11	\$7.90	\$7.84	\$7.99	\$19.49	\$6.15

**Working Capital for Storage Gas Cost Allocation
Ratio of Full Service Customers to All Customers**

(Statistical Analysis - Load Following)

(MDT)	Total	Average	Sales	Transport	Customer Allocation	
Available Storage Capacity	35,164		Storage Utilization		Full Svc	Transport
Baseload	5,788	17%	17%	0%		
Reliability	9,254	26%	26%	26%		
Load Following*	20,122	57%	57%	57%		
		100%	100%	83%	54%	46%

Ratio of Full Service Customers to All Customers **1.17 : 1.00**

(Planned Baseload)

(MDT)	Total	Average	Sales	Transport	Customer Allocation	
Available Storage Capacity	35,164		Storage Utilization		Full Svc	Transport
Baseload	11,150	32%	32%	0%		
Reliability	9,254	26%	26%	26%		
Load Following*	14,760	42%	42%	42%		
		100%	100%	68%	57%	43%

Ratio of Full Service Customers to All Customers **1.32 : 1.00**

* Includes Intra-Day and Day Ahead Utilization

ORANGE AND ROCKLAND UTILITIES, INC.

INDEX OF SCHEDULES

General Inflation Factors

SCHEDULE

TITLE OF SCHEDULE

WITNESS

1

Projected Gross Domestic Product Price Index

Accounting Panel

GDP Deflator-2000=100Forecast Prepared October 2008

	2004	2005	2006	2007	Forecast				
					2008	2009	2010	2011	2012
Mar. 31	108.2	111.8	115.5	118.9	121.6	124.3	127.0	129.7	132.4
Jun. 30	109.2	112.4	116.3	119.5	122.0	124.9	127.6	130.3	133.1
Sep. 30	109.8	113.5	117.1	120.0	123.2	125.5	128.3	131.0	133.7
Dec. 31	110.7	114.5	117.7	120.8	123.7	126.2	129.0	131.7	134.5
Average	109.5	113.0	116.7	119.8	122.6	125.2	128.0	130.7	133.4
Annual Average									
Year-over-year % change	2.9%	3.3%	3.2%	2.7%	2.3%	2.1%	2.2%	2.1%	2.1%

Average 12 months Ending Dec. 31, 2007	(Actual)	=	119.8
Average 12 months Ending Jun 30, 2008	(Actual)	=	121.1
Average 12 months Ending Dec. 31, 2008	(Forecast)	=	122.6
Average 12 months Ending Dec. 31, 2009	(Forecast)	=	125.2
Average 12 months Ending Oct. 31, 2010	(Forecast)	=	127.5
Average 12 months Ending Dec. 31, 2010	(Forecast)	=	128.0
Average 12 months Ending Oct 31, 2011	(Forecast)	=	130.2
Average 12 months Ending Dec. 31, 2011	(Forecast)	=	130.7
Average 12 months Ending Oct. 31, 2012	(Forecast)	=	133.0
Average 12 months Ending Dec. 31, 2012	(Forecast)	=	133.4

Escalation rate for the 24 Months		
Ending 10/31/10 over		
6/30/08 - Rate Year 1	=	1.053
	or	5.3%
Rate Year 2 (increase over Rate Year 1)		
	=	1.021
	or	2.1%
Rate Year 3 (increase over Rate Year 1)		
	=	1.021
	or	2.1%

Notes: Actual GDP deflator from press release by U.S. Department of Commerce Bureau of Economic Analysis as of 9/18/08.
Quarterly Forecasts for 2008 and 2009 from Blue Chip dated October 10, 2008.

Annual Forecasts for 2010 on are from **Blue Chip** dated October 10, 2008.

The quarterly values for 2010 on are extrapolated by applying the year-over-year rate to the prior year's corresponding quarter.

Orange and Rockland Utilities, Inc.
Summary of Dollars and Volumes for Prior Month Adjustments
2001 - 2008

<u>Year</u>	<u>Months</u>	<u>Company</u>	<u>Additional Costs Incurred</u>	<u>Volumes (in Dths) Paid back to:</u>
2001	March - December	O&R	\$ 253,010.76	155,401
		<u>Marketers</u>	\$ 168,701.90	138,847
			\$ 84,308.86	<=== Additional Costs Incurred by O&R
2002	January - December	O&R	\$ 465,671.42	88,506
		<u>Marketers</u>	\$ 198,927.47	800,754
			\$ 266,743.95	<=== Additional Costs Incurred by O&R
2003	January - December	O&R	\$ 1,102,340.40	1,452,855
		<u>Marketers</u>	\$ 1,568,219.75	-
			\$ (465,879.35)	<=== Additional Costs Incurred by Marketers
2004	January - December	O&R	\$ 392,367.62	152,918
		<u>Marketers</u>	\$ 105,379.47	306,813
			\$ 286,988.15	<=== Additional Costs Incurred by O&R
2005	January - December	O&R	\$ 254,559.02	290,336
		<u>Marketers</u>	\$ 574,423.15	340,854
			\$ (319,864.13)	<=== Additional Costs Incurred by Marketers
2006	January - December	O&R	\$ 126,603.04	61,583
		<u>Marketers</u>	\$ 1,636,448.32	720,814
			\$ (1,509,845.28)	<=== Additional Costs Incurred by Marketers
2007	January - December	O&R	\$ 505,398.43	569,267
		<u>Marketers</u>	\$ 420,397.98	578,594
			\$ 85,000.44	<=== Additional Costs Incurred by O&R
2008	January - December	O&R	\$ 678,211.67	409,769
		<u>Marketers</u>	\$ 1,025,469.82	294,548
			\$ (347,258.16)	<=== Additional Costs Incurred by Marketers
Totals	January - December	O&R	\$ 3,778,162.35	3,180,635
		<u>Marketers</u>	\$ 5,782,968.31	3,181,224
			\$ (2,004,805.96)	<=== Additional Costs Incurred by Marketers

ORANGE AND ROCKLAND UTILITIES, INC.

**PROPOSED DEPRECIATION RATE CHANGES
FOR GAS PLANT AT DECEMBER 31, 2007**

NOVEMBER 2008

ORANGE AND ROCKLAND UTILITIES INC.
PROPOSED DEPRECIATION RATE CHANGES FOR GAS PLANT
AT DECEMBER 31, 2007

ACCT. NO.	ACCOUNT TITLE	BOOK BASIS					PROPOSED BASIS										
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
PRODUCTION PLANT																	
304000	LAND - EASEMENTS	12,878			5,248	h 3.0	50	-	258	4,762	487	h 3.0	50	-	258	4,762	487
304102	LAND - FEE	621				-	-	-	-	-	-	-	-	-	-	-	-
305000	STRUCTURES & IMPROVEMENTS	690,200			(36,694)	h 2.0	35	(20)	23,674	316,273	(352,967)	h 1.5	25	(20)	33,130	344,631	(381,325)
311002	LP GAS EQUIPMENT	1,119,765			(442,160)	h 2.5	30	(30)	48,486	726,100	(1,168,260)	h 1.5	25	(30)	58,228	648,947	(1,091,106)
	TOTAL PRODUCTION PLANT	1,823,464			(473,605)				72,418	1,047,135	(1,520,740)				91,616	998,340	(1,471,944)
TRANSMISSION PLANT																	
367002	MAINS	27,621,765			3,602,630	h 2.5	75	(40)	516,527	4,060,402	(457,772)	h 3.0	70	(40)	552,435	3,619,719	(17,088)
367322	MAINS - STEEL - STONY POINT	589,448			589,448	(A)	-	-	-	589,448	-	(A)	-	-	-	589,448	-
367502	MAINS - LEDERLE	543,773			543,773	(A)	-	-	-	543,773	-	(A)	-	-	-	543,773	-
	TOTAL TRANSMISSION PLANT	28,754,986			4,735,851				516,527	5,193,623	(457,772)				552,435	4,752,939	(17,088)
DISTRIBUTION PLANT																	
374000	LAND - EASEMENTS	874,918			284,757	h 3.0	60	-	14,611	249,214	35,544	h 3.0	60	-	14,611	249,214	35,544
374100	LAND - FEE	823,499				(A)	-	-	-	-	-	(A)	-	-	-	-	-
374200	LAND - FEE - CLEVEPAK	14,136			14,136	(A)	-	-	-	14,136	-	(A)	-	-	-	14,136	-
375000	STRUCTURES & IMPROVEMENTS	3,300,213			1,207,300	h 1.5	45	(30)	95,376	969,525	237,775	h 1.5	55	(30)	77,885	821,414	385,886
375100	ST. & IMPROV. - STONY POINT MAIN	171,439			171,439	(A)	-	-	-	171,439	-	(A)	-	-	-	171,439	-
376000	MAINS	160,498,397			42,293,900	h 2.5	75	(40)	3,001,320	47,564,144	(5,270,244)	h 3.0	70	(40)	3,208,968	42,226,832	67,067
376200	MAINS - CLEVEPAK	585,383			585,383	(A)	-	-	-	585,383	-	(A)	-	-	-	585,383	-
376300	MAINS - TRANSCO	2,764,222			2,764,222	(A)	-	-	-	2,764,222	-	(A)	-	-	-	2,764,222	-
377000	COMPRESSOR STATION EQUIPMENT	744			(335)	h 2.0	35	(5)	22	530	(865)	h 2.0	35	(5)	22	530	(865)
378000	MEASURING AND REGULATING EQ.	10,846,238			3,379,611	h 1.5	30	(30)	489,729	3,445,104	(65,493)	h 1.5	30	(20)	433,930	3,180,086	199,515
378100	MEAS. & REG. EQ. - STONY POINT	728,154			728,154	(A)	-	-	-	728,154	-	(A)	-	-	-	728,154	-
378300	MEAS. & REG. EQ. - TRANSCO	394,763			394,763	(A)	-	-	-	394,763	-	(A)	-	-	-	394,763	-
378340	MEAS. & REG. EQ. - TRANSCO ORDER 63	1,068,296			1,068,296	(A)	-	-	-	1,068,296	-	(A)	-	-	-	1,068,296	-
380000	SERVICES	130,618,371			47,617,458	h 2.0	60	(80)	3,918,551	44,165,207	3,452,251	h 2.5	60	(80)	3,918,551	48,779,960	(1,162,502)
381000	METERS	11,275,337			3,697,761	h 2.5	35	5	305,562	3,697,432	(9,671)	h 2.5	35	5	322,475	3,892,034	(204,273)
381100	METERS - SPECIAL TYPES	615,157			240,436	h 2.5	35	5	16,671	218,412	22,023	h 2.5	35	5	17,593	229,908	10,528
382000	METER INSTALLATIONS	17,086,583			3,394,422	h 2.5	50	-	341,732	4,513,378	(1,118,958)	h 2.5	45	(30)	493,802	6,420,468	(3,026,066)
382100	METER INST. - SPECIAL TYPES	925,887			49,208	h 2.5	50	-	18,578	73,217	(24,009)	h 2.5	45	(30)	26,758	105,054	(55,846)
382400	METER BAR INSTALLATIONS	4,191,581			174,772	h 2.5	50	-	83,832	355,581	(180,809)	h 2.5	45	(30)	121,137	512,211	(337,440)
383000	HOUSE REGULATORS	2,719,621			1,105,761	h 2.5	35	5	73,702	990,078	115,682	h 2.5	35	5	77,781	1,042,188	63,573
384000	HOUSE REGULATOR INSTALLATIONS	5,573,291			1,784,755	h 2.5	50	-	111,466	1,744,210	40,544	h 2.5	45	(30)	161,068	2,468,285	(683,550)
385000	INDUSTRIAL MEAS. & REG. EQ.	3,578,087			836,967	h 3.0	40	(5)	94,104	806,365	30,602	h 3.5	35	-	102,333	893,751	(56,784)
385500	IND. MEAS. & REG. EQ. - LEDERLE	143,262			143,262	(A)	-	-	-	143,262	-	(A)	-	-	-	143,262	-
386000	OTHER PROP. ON CUSTS. - PREM.	265,003			129,126	h 2.0	20	-	13,250	111,394	17,732	h 2.0	20	-	13,250	111,394	17,732
	TOTAL DISTRIBUTION PLANT	359,064,562			112,055,552				8,558,446	114,773,447	(2,717,894)				8,951,164	116,803,013	(4,747,461)

ORANGE AND ROCKLAND UTILITIES INC.
PROPOSED DEPRECIATION RATE CHANGES FOR GAS PLANT
AT DECEMBER 31, 2007

		BOOK BASIS					PROPOSED BASIS									
ACCT. NO.	ACCOUNT TITLE	BOOK COST	ACCUMULATED PROVISION FOR DEPRECIATION		LIFE TABLE	AVERAGE SERVICE LIFE	NET SALVAGE	ANNUAL DEPRECIATION EXPENSE	COMPUTED RESERVE FOR DEPRECIATION	RESERVE VARIATION	LIFE TABLE	AVERAGE SERVICE LIFE	NET SALVAGE	ANNUAL DEPRECIATION EXPENSE	COMPUTED RESERVE FOR DEPRECIATION	RESERVE VARIATION
			(4)	(5)												
(1)	(2)	(3)														
GENERAL PLANT EQUIPMENT																
389100	LAND - FEE	2,737	-	-	h 1.5	50	-	(10)	6,284	-	-	-	-	-	-	-
390000	STRUCTURES AND IMPROVEMENTS	285,634	11,612	h 1.5	50	25	-	-	41,605	(29,994)	h 1.5	50	(20)	6,855	45,388	(33,776)
391100	OFFICE FURNITURE & EQ. - FURNITURE	139,609	(7,739)	h 0.5	25	5	-	5	28,952	(36,691)	h 1.5	20	-	6,980	54,579	(62,317)
391200	OFFICE FURNITURE & EQ. - MACHINES	6,261	(18,651)	h 1.0	20	-	-	-	2,271	(20,922)	h 1.0	18	-	348	2,445	(21,096)
391700	OFFICE FURNITURE & EQ. - EDP EQ.	480,040	120,793	h 2.0	8	-	-	-	108,013	12,780	h 1.5	10	-	48,004	76,210	44,583
391800	OFFICE FURNITURE & EQ. - ECC	-	29,144	h 2.0	10	-	-	-	-	29,144	h 2.5	10	-	-	-	29,144
392100	TRANSPORTATION EQ. - PASS. CARS	169,959	72,339	h 2.0	7	15	-	15	39,560	32,780	h 2.0	8	10	19,120	37,281	35,059
392200	TRANS. EQ. - LIGHT TRUCKS	813,262	334,904	h 2.0	7	15	-	15	98,730	193,185	h 2.0	8	10	91,492	187,588	147,588
392300	TRANS. EQ. - HEAVY TRUCKS	2,133,849	657,786	h 3.0	10	10	-	10	192,046	129,795	h 3.0	12	5	169,001	486,315	171,471
392400	TRANS. - TRAILERS	84,921	67,939	h 2.0	15	10	-	10	51,478	16,461	h 3.0	12	5	6,726	67,606	333
393000	STORES EQUIPMENT	17,522	4,734	h 2.0	30	-	-	30	4,309	424	h 2.0	25	-	701	4,884	(151)
394000	TOOLS & WORK EQUIPMENT	2,588,764	912,620	h 1.0	20	-	-	-	660,013	252,607	h 1.5	20	-	129,438	794,590	118,029
395000	LABORATORY EQUIPMENT	601,794	54,706	h 1.0	30	-	-	-	97,304	(42,598)	h 1.5	30	-	20,040	118,171	(63,465)
396000	POWER OPERATED EQUIPMENT	944,059	278,802	h 2.5	15	25	-	25	164,106	114,696	h 3.0	17	20	44,465	167,095	111,707
397000	COMMUNICATION EQUIPMENT	232,658	(193,618)	h 1.5	25	-	-	-	5,674	(199,291)	h 1.0	20	-	11,633	5,670	(199,288)
397200	COM. EQ. - TELEPHONES	9,677	3,611	h 1.5	25	-	-	-	3,307	305	h 1.0	20	-	484	3,239	372
398000	MISCELLANEOUS EQUIPMENT	130,425	22,804	h 2.0	25	-	-	-	32,656	(9,852)	h 1.5	25	-	5,217	28,191	(5,388)
	TOTAL GENERAL PLANT	8,641,171	2,351,787						1,960,423	391,363				560,504	2,078,980	272,805
INTANGIBLE PLANT																
302100	FRANCHISES AND CONSENTS	13,893	-	-	-	-	-	-	-	-	-	-	-	-	-	-
302200	FRANCHISES & CONSENTS - AMORT.	6,933	6,933	(A)	-	-	-	-	6,933	-	(A)	-	-	-	6,933	-
303630	GAS INSPECTION MGT. SYSTEM	1,005,768	525,740	(A)	-	-	-	-	525,740	-	(A)	-	-	-	525,740	-
303850	GAS MOBILE DISPATCH SYSTEM	2,260,747	1,192,233	(A)	-	-	-	-	1,192,233	-	(A)	-	-	-	1,192,233	-
303880	GMS - PHASE 2	284,332	9,478	(A)	-	-	-	-	9,478	-	(A)	-	-	-	9,478	-
	TOTAL INTANGIBLE PLANT	3,571,674	1,734,384						1,734,384	-				-	1,734,384	-
TOTAL GAS PLANT- EXCLUDING UNALLOCATED RES																
		401,855,877	120,403,970						9,747,976	(4,305,043)				10,195,719	126,367,656	(5,963,688)
RESERVE VARIATION PERCENTAGE																
		-	3,933,786						(547,000)	-3.45%				(547,000)	-	-4.72%
UNALLOCATED RESERVE																
		-	-						-	3,933,786				-	-	3,933,786
TOTAL O&B GAS PLANT																
		401,855,877	124,337,755						9,200,976	(371,257)				9,648,719	126,367,656	(2,029,902)

(A) AMORTIZABLE - ACCUMULATED PROVISION FOR DEPRECIATION PER BOOKS AT DECEMBER 31, 2007 USED FOR COMPUTED RESERVE.

ORANGE AND ROCKLAND UTILITIES, INC.

GAS PLANT

**SUMMARY OF AVERAGE SERVICE LIVES, EQUIVALENT "h" CURVES AND OTHER
STATISTICAL DATA INDICATED BY PLANT MORTALITY STUDIES
BASED ON EXPERIENCE THROUGH DECEMBER 31, 2007**

NOVEMBER 2008

ORANGE AND ROCKLAND UTILITIES INC. MORTALITY STUDY BY LEAST SQUARE FITTING OF WEIGHTED RETIREMENT RATIOS
ACCOUNT 2305000 STRUCTURES AND IMPROVEMENTS PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2007
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		40.99	0.015180	286.65	2.53	36.86	0.014262	183.15	2.01	39.39	0.013547	145.96	3.15
1953 TO 1962		41.14	0.013922	288.03	2.49	38.04	0.013093	180.08	2.16	40.02	0.012264	146.19	3.22
1954 TO 1963		26.86	0.022805	277.40	2.64	29.88	0.021725	199.14	1.48	32.54	0.020908	164.43	2.11
1955 TO 1964		20.35	0.027614	326.80	1.87	20.71	0.027559	287.27	0.62	19.62	0.025602	262.47	0.57
1956 TO 1965		19.66	0.027589	323.02	1.97	19.86	0.027537	289.56	0.70	19.32	0.025151	266.50	0.48
1957 TO 1966		19.13	0.027765	311.06	2.13	19.40	0.027640	286.11	0.79	19.24	0.024257	257.22	0.31
1958 TO 1967		18.44	0.026166	328.11	1.88	18.37	0.026420	318.37	1.50	18.25	0.025199	276.65	0.74
1959 TO 1968		18.08	0.025995	312.49	2.09	18.17	0.026249	305.49	1.79	17.67	0.025421	285.74	1.05
1960 TO 1969		17.52	0.027411	293.90	2.31	17.81	0.027674	289.12	2.06	17.06	0.027308	296.05	1.45
1961 TO 1970		16.16	0.026367	281.63	2.55	16.26	0.026657	279.76	2.48	15.89	0.026864	292.58	2.31
1962 TO 1971		16.05	0.026958	258.62	2.91	16.37	0.027238	259.65	2.75	16.22	0.027519	261.95	2.69
1963 TO 1972		15.33	0.026860	225.04	3.82	16.45	0.025102	221.92	2.74	16.02	0.024793	234.15	2.69
1964 TO 1973		17.25	0.024441	287.40	2.59	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1965 TO 1974		25.26	0.010708	285.00	2.48	25.07	0.010744	209.43	3.41	25.05	0.012742	173.66	4.40
1966 TO 1975		24.30	0.012980	286.04	2.48	24.51	0.012585	189.72	3.91	25.30	0.009965	175.87	4.32
1967 TO 1976		24.93	0.010328	298.89	2.31	24.96	0.009833	190.30	4.01	25.30	0.009965	175.87	4.32
1968 TO 1977		25.63	0.009312	302.39	2.23	25.40	0.008868	190.95	3.99	25.61	0.008990	181.58	4.19
1969 TO 1978		25.96	0.007900	313.99	2.10	25.69	0.007580	196.60	3.79	25.84	0.007680	183.84	3.96
1970 TO 1979		26.48	0.007488	326.63	1.91	25.93	0.007311	202.49	3.42	25.63	0.007378	185.34	3.31
1971 TO 1980		42.55	0.004483	348.99	1.65	33.98	0.004491	216.31	3.01	31.29	0.004439	164.61	3.39
1972 TO 1981		40.99	0.003451	342.77	1.72	34.00	0.003447	222.06	2.92	32.01	0.003438	173.38	3.38
1973 TO 1982		42.40	0.003131	340.83	1.75	34.81	0.003123	219.77	2.98	32.97	0.003120	174.39	3.54
1974 TO 1983		48.17	0.002425	345.65	1.68	37.24	0.002410	218.82	2.97	34.60	0.002375	169.09	3.83
1975 TO 1984		51.89	0.002254	345.92	1.69	39.14	0.002246	221.00	2.95	36.22	0.002233	169.82	3.88
1976 TO 1985		86.52	0.000688	369.28	1.41	0.00	0.000000	0.00	0.00	53.69	0.000653	181.59	3.18
1977 TO 1986		98.90	0.000640	372.60	1.37	0.00	0.000000	0.00	0.00	59.02	0.000653	187.23	3.11
1978 TO 1987		115.51	0.000643	344.98	1.30	110.47	0.000649	344.44	1.46	65.47	0.000656	193.22	3.01
1979 TO 1988		82.76	0.000913	363.11	1.48	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1980 TO 1989		81.09	0.000814	345.93	1.70	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1981 TO 1990		85.79	0.000711	346.78	1.67	0.00	0.000000	0.00	0.00	60.54	0.000719	180.87	3.31
1982 TO 1991		56.71	0.002583	337.67	1.79	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1983 TO 1992		43.22	0.004560	322.78	1.99	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1984 TO 1993		46.12	0.004256	321.97	1.99	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1985 TO 1994		35.92	0.005771	302.02	2.27	35.90	0.005823	299.44	2.28	0.00	0.000000	0.00	0.00
1986 TO 1995		32.60	0.005370	305.20	2.23	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1987 TO 1996		33.22	0.004944	314.21	2.20	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1988 TO 1997		34.85	0.003685	319.36	2.02	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1989 TO 1998		36.79	0.003239	328.37	1.92	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1990 TO 1999		38.52	0.003052	334.94	1.82	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1991 TO 2000		40.46	0.002943	341.64	1.73	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1992 TO 2001		44.05	0.002415	462.38	1.45	16.22	0.017241	446.96	0.43	41.06	0.002974	254.51	1.86
1993 TO 2002		16.33	0.017107	485.14	0.30	0.00	0.000000	0.00	0.00	40.12	0.002417	203.15	2.28
1994 TO 2003		15.56	0.016050	550.20	-0.23	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1995 TO 2004		14.99	0.016322	573.85	-0.46	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1996 TO 2005		15.25	0.015658	644.34	-1.08	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1997 TO 2006		14.51	0.013819	751.95	-2.17	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1998 TO 2007		13.50	0.013765			0.00	0.000000			0.00	0.000000		

ORANGE AND ROCKLAND UTILITIES INC. MORTALITY STUDY BY LEAST SQUARE FITTING OF WEIGHTED RETIREMENT RATIOS
ACCOUNT 2305000 STRUCTURES AND IMPROVEMENTS PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2007

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
2007 TO 2007	2007 TO 2007	399.00	0.000000	99.87	5.10	399.00	0.000000	99.87	5.10	399.00	0.000000	99.87	5.10
2006 TO 2007	2006 TO 2007	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 2007	2005 TO 2007	399.00	0.000000	99.87	5.10	399.00	0.000000	99.87	5.10	399.00	0.000000	99.87	5.10
2004 TO 2007	2004 TO 2007	0.00	0.000000	0.00	0.00	64.39	0.002050	199.55	2.46	0.00	0.000000	0.00	0.00
2003 TO 2007	2003 TO 2007	101.43	0.002240	392.88	-1.34	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
2002 TO 2007	2002 TO 2007	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00	7.19	0.020544	1396.89	-1.74
2001 TO 2007	2001 TO 2007	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00	9.08	0.019003	1910.42	-2.60
2000 TO 2007	2000 TO 2007	9.64	0.016251	959.66	-2.60	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1999 TO 2007	1999 TO 2007	11.60	0.014715	857.45	-2.60	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1998 TO 2007	1998 TO 2007	13.50	0.013765	751.95	-2.17	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1997 TO 2007	1997 TO 2007	15.28	0.012785	670.74	-1.30	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1996 TO 2007	1996 TO 2007	16.72	0.012244	612.89	-0.74	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1995 TO 2007	1995 TO 2007	17.01	0.011450	590.82	-0.57	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1994 TO 2007	1994 TO 2007	17.67	0.010928	540.55	-0.17	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1993 TO 2007	1993 TO 2007	18.73	0.010589	520.53	0.02	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1992 TO 2007	1992 TO 2007	19.28	0.009845	500.48	0.18	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1991 TO 2007	1991 TO 2007	19.75	0.009480	488.66	0.27	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1990 TO 2007	1990 TO 2007	20.48	0.008909	471.22	0.39	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1989 TO 2007	1989 TO 2007	21.19	0.008490	460.14	0.51	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1988 TO 2007	1988 TO 2007	21.71	0.007964	449.08	0.61	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1987 TO 2007	1987 TO 2007	22.30	0.007659	437.18	0.72	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1986 TO 2007	1986 TO 2007	22.84	0.007477	422.57	0.82	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1985 TO 2007	1985 TO 2007	23.31	0.007079	413.93	0.92	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1984 TO 2007	1984 TO 2007	23.73	0.006889	402.45	1.01	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1983 TO 2007	1983 TO 2007	24.02	0.006741	397.60	1.08	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1982 TO 2007	1982 TO 2007	24.32	0.006589	388.64	1.15	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1981 TO 2007	1981 TO 2007	24.52	0.006473	385.40	1.20	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1980 TO 2007	1980 TO 2007	24.71	0.006390	382.44	1.25	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1979 TO 2007	1979 TO 2007	24.78	0.006271	381.30	1.26	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1978 TO 2007	1978 TO 2007	24.87	0.006208	379.97	1.27	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1977 TO 2007	1977 TO 2007	24.96	0.006173	378.66	1.29	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1976 TO 2007	1976 TO 2007	25.03	0.006133	377.54	1.30	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1975 TO 2007	1975 TO 2007	25.04	0.006102	373.38	1.32	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1974 TO 2007	1974 TO 2007	25.09	0.006087	372.68	1.33	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1973 TO 2007	1973 TO 2007	25.09	0.006060	372.72	1.33	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1972 TO 2007	1972 TO 2007	25.12	0.006054	372.21	1.33	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1971 TO 2007	1971 TO 2007	25.15	0.006032	371.75	1.33	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1970 TO 2007	1970 TO 2007	25.01	0.006055	369.82	1.35	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1969 TO 2007	1969 TO 2007	25.04	0.006048	369.36	1.35	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1968 TO 2007	1968 TO 2007	25.08	0.006020	368.88	1.36	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1967 TO 2007	1967 TO 2007	25.11	0.006007	372.42	1.36	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1966 TO 2007	1966 TO 2007	25.13	0.006001	372.02	1.36	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1965 TO 2007	1965 TO 2007	25.14	0.005989	367.91	1.37	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1964 TO 2007	1964 TO 2007	24.47	0.006320	357.61	1.52	24.15	0.006350	316.74	1.55	24.39	0.006327	272.61	1.57
1963 TO 2007	1963 TO 2007	23.82	0.006601	337.99	1.78	23.44	0.006571	287.95	1.71	23.55	0.006611	278.14	1.72
1962 TO 2007	1962 TO 2007	23.94	0.006528	340.39	1.72	23.65	0.006533	302.28	1.68	23.69	0.006581	297.63	1.68
1961 TO 2007	1961 TO 2007	23.93	0.006504	340.59	1.72	23.70	0.006520	305.94	1.67	0.00	0.000000	0.00	0.00
1960 TO 2007	1960 TO 2007	24.05	0.006512	343.06	1.67	23.87	0.006543	316.25	1.64	0.00	0.000000	0.00	0.00
1959 TO 2007	1959 TO 2007	24.16	0.006508	349.75	1.62	24.04	0.006548	326.59	1.60	0.00	0.000000	0.00	0.00
1958 TO 2007	1958 TO 2007	24.26	0.006507	352.43	1.58	24.18	0.006551	337.06	1.57	0.00	0.000000	0.00	0.00
1957 TO 2007	1957 TO 2007	24.22	0.006566	344.72	1.64	24.10	0.006604	325.76	1.61	0.00	0.000000	0.00	0.00
1956 TO 2007	1956 TO 2007	24.34	0.006569	351.30	1.60	24.25	0.006613	331.95	1.58	0.00	0.000000	0.00	0.00
1955 TO 2007	1955 TO 2007	24.45	0.006581	353.73	1.56	24.40	0.006627	342.26	1.55	0.00	0.000000	0.00	0.00

ORANGE AND ROCKLAND UTILITIES INC. MORTALITY STUDY BY LEAST SQUARE FITTING OF WEIGHTED RETIREMENT RATIOS
ACCOUNT 2305000 STRUCTURES AND IMPROVEMENTS PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2007

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)
1954 TO 2007		24.56	0.006579	356.29	1.52	24.53	0.006627	348.58	1.51	0.00	0.000000	0.00	0.00
1953 TO 2007		24.67	0.006583	358.76	1.49	24.66	0.006632	358.88	1.49	0.00	0.000000	0.00	0.00
1952 TO 2007		24.77	0.006487	361.26	1.46	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
ACCOUNT 2311002 LP-GAS EQUIPMENT PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2007

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
1962 TO 1971	1962 TO 1971	399.00	0.000000	99.87	5.10	399.00	0.000000	99.87	5.10	399.00	0.000000	99.87	5.10
1963 TO 1972	1963 TO 1972	399.00	0.000000	99.87	5.10	399.00	0.000000	99.87	5.10	399.00	0.000000	99.87	5.10
1964 TO 1973	1964 TO 1973	399.00	0.000000	99.87	5.10	399.00	0.000000	99.87	5.10	399.00	0.000000	99.87	5.10
1965 TO 1974	1965 TO 1974	399.00	0.000000	99.87	5.10	399.00	0.000000	99.87	5.10	399.00	0.000000	99.87	5.10
1966 TO 1975	1966 TO 1975	126.93	0.000548	313.95	1.76	63.49	0.000527	213.41	3.35	47.08	0.000485	162.50	5.10
1967 TO 1976	1967 TO 1976	134.34	0.000522	296.63	1.75	67.94	0.000511	215.64	3.29	50.96	0.000500	165.80	5.10
1968 TO 1977	1968 TO 1977	157.04	0.000478	253.75	1.66	71.38	0.000468	216.44	3.24	54.79	0.000466	168.81	4.70
1969 TO 1978	1969 TO 1978	150.42	0.000438	264.92	1.64	79.22	0.000438	224.06	2.99	65.66	0.000444	183.53	3.83
1970 TO 1979	1970 TO 1979	156.29	0.000372	254.98	1.64	85.87	0.000373	228.84	2.89	0.00	0.000000	0.00	0.00
1971 TO 1980	1971 TO 1980	74.32	0.002388	345.13	1.70	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1972 TO 1981	1972 TO 1981	77.37	0.002281	347.05	1.68	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1973 TO 1982	1973 TO 1982	63.60	0.002331	340.42	1.76	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1974 TO 1983	1974 TO 1983	66.96	0.002252	341.26	1.74	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1975 TO 1984	1975 TO 1984	70.64	0.002416	344.73	1.71	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1976 TO 1985	1976 TO 1985	72.73	0.001929	358.19	1.53	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1977 TO 1986	1977 TO 1986	77.38	0.001741	363.77	1.47	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1978 TO 1987	1978 TO 1987	81.27	0.001707	363.62	1.47	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1979 TO 1988	1979 TO 1988	72.57	0.001765	352.09	1.61	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1980 TO 1989	1980 TO 1989	75.39	0.001710	354.83	1.57	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1981 TO 1990	1981 TO 1990	70.91	0.001818	337.74	1.80	70.48	0.001838	329.90	1.83	67.12	0.001860	259.98	2.13
1982 TO 1991	1982 TO 1991	73.99	0.001548	342.60	1.73	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1983 TO 1992	1983 TO 1992	72.00	0.001376	345.15	1.70	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1984 TO 1993	1984 TO 1993	74.68	0.001314	347.50	1.66	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1985 TO 1994	1985 TO 1994	48.29	0.005410	303.40	2.25	44.77	0.005324	202.15	3.29	43.79	0.005238	165.57	3.39
1986 TO 1995	1986 TO 1995	49.16	0.005267	308.19	2.20	45.48	0.005210	205.59	3.22	44.06	0.005143	166.81	3.27
1987 TO 1996	1987 TO 1996	50.47	0.004765	310.06	2.16	46.47	0.004711	207.67	3.20	44.81	0.004663	170.72	3.26
1988 TO 1997	1988 TO 1997	51.87	0.004436	313.27	2.12	47.52	0.004391	209.39	3.17	45.70	0.004364	173.95	3.25
1989 TO 1998	1989 TO 1998	54.14	0.003647	324.15	1.97	47.97	0.003575	213.68	2.91	46.45	0.003554	175.46	3.11
1990 TO 1999	1990 TO 1999	55.95	0.003578	345.82	1.68	47.65	0.003496	217.22	2.54	46.34	0.003496	184.49	2.72
1991 TO 2000	1991 TO 2000	61.41	0.003208	350.92	1.61	50.36	0.003136	215.44	2.59	48.89	0.003147	185.11	2.78
1992 TO 2001	1992 TO 2001	59.89	0.003140	354.80	1.57	50.61	0.003105	228.20	2.40	49.40	0.003127	199.40	2.56
1993 TO 2002	1993 TO 2002	13.00	0.017602	626.80	-0.91	12.52	0.017692	562.96	-2.00	12.65	0.017815	525.58	-1.39
1994 TO 2003	1994 TO 2003	11.82	0.017865	646.99	-1.09	11.46	0.017986	606.44	-2.00	11.67	0.018085	552.58	-1.13
1995 TO 2004	1995 TO 2004	11.02	0.019075	721.17	-1.84	10.91	0.019242	691.84	-2.20	11.14	0.019355	596.91	-1.19
1996 TO 2005	1996 TO 2005	10.35	0.021882	748.56	-2.12	10.27	0.022075	725.64	-2.45	10.52	0.022225	632.14	-1.29
1997 TO 2006	1997 TO 2006	9.37	0.024131	794.93	-2.60	9.31	0.024345	789.06	-2.60	9.62	0.024524	680.81	-1.50
1998 TO 2007	1998 TO 2007	8.40	0.026195	839.68	-2.60	8.38	0.026427	841.72	-2.60	8.69	0.026634	742.17	-1.77

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. 2007

ACCOUNT 2311002 LP-GAS EQUIPMENT

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
2007 TO 2007	2007	182.74	0.003241	218.07	1.84	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
2006 TO 2007	2007	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00	59.62	0.004461	165.21	2.71
2005 TO 2007	2007	204.95	0.003132	194.43	0.72	0.00	0.000000	0.00	0.00	68.05	0.003139	165.33	2.89
2004 TO 2007	2007	218.50	0.002691	182.38	1.07	0.00	0.000000	0.00	0.00	72.00	0.002705	163.19	3.15
2003 TO 2007	2007	33.32	0.014322	673.67	-1.33	0.00	0.000000	0.00	0.00	28.14	0.014092	289.66	0.52
2002 TO 2007	2007	3.23	0.042381	1067.14	-2.60	0.00	0.000000	0.00	0.00	4.05	0.042936	851.78	-0.65
2001 TO 2007	2007	4.56	0.036106	931.49	-2.60	0.00	0.000000	0.00	0.00	5.24	0.036668	811.70	-1.03
2000 TO 2007	2007	6.00	0.030847	891.93	-2.60	0.00	0.000000	0.00	0.00	6.61	0.031334	808.92	-1.06
1999 TO 2007	2007	7.21	0.028116	866.70	-2.60	0.00	0.000000	0.00	0.00	7.65	0.028577	791.08	-1.45
1998 TO 2007	2007	8.40	0.026195	839.68	-2.60	8.38	0.026427	841.72	-2.60	8.89	0.026634	742.17	-1.77
1997 TO 2007	2007	9.71	0.023526	808.42	-2.60	9.67	0.023735	791.00	-2.60	9.97	0.023914	677.29	-1.59
1996 TO 2007	2007	11.00	0.020912	759.32	-2.28	10.95	0.021098	744.01	-2.44	11.21	0.021247	611.19	-1.35
1995 TO 2007	2007	12.00	0.017927	737.34	-1.99	12.81	0.018085	715.30	-2.13	12.19	0.018198	570.29	-1.20
1994 TO 2007	2007	13.08	0.016739	661.14	-1.17	13.79	0.016870	597.29	-1.75	13.05	0.016963	517.20	-1.01
1993 TO 2007	2007	14.06	0.016020	636.40	-1.00	14.60	0.015405	569.27	-1.48	13.99	0.016234	489.56	-0.89
1992 TO 2007	2007	14.86	0.015286	622.50	-0.85	15.47	0.014670	551.29	-1.21	14.77	0.014748	451.84	-0.74
1991 TO 2007	2007	15.73	0.014558	607.17	-0.71	16.17	0.013640	510.23	-0.83	15.60	0.013709	433.14	-0.52
1990 TO 2007	2007	16.44	0.013539	586.98	-0.56	16.91	0.013296	493.82	-0.69	16.99	0.013364	420.82	-0.43
1989 TO 2007	2007	17.20	0.013201	578.52	-0.46	17.45	0.013008	478.49	-0.61	17.55	0.013082	407.45	-0.38
1988 TO 2007	2007	17.79	0.012919	564.77	-0.38	18.03	0.012760	463.16	-0.53	18.14	0.012837	399.71	-0.32
1987 TO 2007	2007	18.43	0.012678	556.29	-0.30	18.61	0.012091	448.67	-0.43	18.73	0.012165	387.16	-0.24
1986 TO 2007	2007	19.05	0.012019	548.60	-0.22	19.08	0.011724	442.96	-0.35	19.20	0.011794	377.61	-0.16
1985 TO 2007	2007	19.54	0.011657	540.02	-0.16	19.63	0.011122	430.42	-0.24	19.75	0.011187	367.01	-0.07
1984 TO 2007	2007	20.11	0.011063	529.46	-0.07	20.15	0.010947	419.46	-0.14	20.27	0.011012	362.63	0.01
1983 TO 2007	2007	20.65	0.010891	520.57	0.01	20.56	0.010737	411.00	-0.04	20.68	0.010802	355.43	0.10
1982 TO 2007	2007	21.06	0.010681	510.45	0.09	21.02	0.010589	401.97	0.05	21.14	0.010653	347.73	0.18
1981 TO 2007	2007	21.53	0.010535	499.32	0.16	21.26	0.010353	402.26	0.10	21.39	0.010416	343.63	0.24
1980 TO 2007	2007	21.76	0.010300	493.91	0.21	21.62	0.010161	395.51	0.16	21.76	0.010225	342.29	0.29
1979 TO 2007	2007	22.16	0.010112	489.69	0.26	21.97	0.010011	389.18	0.23	22.13	0.010075	336.71	0.35
1978 TO 2007	2007	22.52	0.009964	481.71	0.32	22.31	0.009796	383.31	0.29	22.47	0.009858	331.62	0.41
1977 TO 2007	2007	22.87	0.009752	474.52	0.37	22.66	0.009662	377.27	0.36	22.82	0.009723	326.49	0.48
1976 TO 2007	2007	23.21	0.009618	467.49	0.43	23.00	0.009530	371.74	0.44	23.14	0.009589	321.94	0.55
1975 TO 2007	2007	23.51	0.009485	461.42	0.49	23.34	0.009387	366.37	0.51	23.45	0.009444	317.63	0.61
1974 TO 2007	2007	23.81	0.009343	455.62	0.54	23.66	0.009110	358.66	0.57	23.74	0.009161	313.83	0.66
1973 TO 2007	2007	24.09	0.009067	450.43	0.60	23.82	0.009042	358.94	0.60	23.91	0.009093	311.58	0.69
1972 TO 2007	2007	24.27	0.009000	447.12	0.62	23.98	0.009000	356.60	0.62	24.07	0.009052	309.46	0.71
1971 TO 2007	2007	24.43	0.008959	444.05	0.64	24.13	0.008950	354.30	0.65	24.23	0.009003	307.43	0.74
1970 TO 2007	2007	24.59	0.008911	441.15	0.67	24.29	0.0088904	352.03	0.68	24.39	0.008957	305.47	0.76
1969 TO 2007	2007	24.75	0.008865	438.43	0.69	24.44	0.008841	349.80	0.71	24.54	0.008893	303.61	0.79
1968 TO 2007	2007	24.89	0.008803	435.89	0.72	24.60	0.008786	347.62	0.74	24.68	0.008837	301.86	0.82
1967 TO 2007	2007	25.03	0.008747	433.52	0.74	24.73	0.008734	345.78	0.76	24.80	0.008784	300.40	0.84
1966 TO 2007	2007	25.14	0.008695	431.51	0.76	24.81	0.008708	344.59	0.78	24.89	0.008759	299.34	0.85
1965 TO 2007	2007	25.23	0.008670	430.01	0.78	24.89	0.008683	343.48	0.79	24.97	0.008734	298.37	0.87
1964 TO 2007	2007	25.31	0.008646	428.64	0.79	24.97	0.008654	342.39	0.81	25.05	0.008706	297.43	0.88
1963 TO 2007	2007	25.39	0.008617	427.35	0.80	25.04	0.008627	341.44	0.83	25.12	0.008677	296.62	0.90
1962 TO 2007	2007	25.45	0.008591	427.36	0.82								

ORANGE AND ROCKLAND UTILITIES INC. MORTALITY STUDY BY LEAST SQUARE FITTING OF WEIGHTED RETIREMENT RATIOS
ACCOUNT 2375000 STRUCTURES AND IMPROVEMENTS PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2007
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
1977 TO 1986		73.90	0.002453	320.04	2.03	56.43	0.002399	199.37	3.67	57.31	0.002376	159.65	5.10
1978 TO 1987		61.52	0.002971	311.30	2.14	50.98	0.002858	195.16	3.62	53.38	0.002792	158.30	5.10
1979 TO 1988		58.72	0.003023	309.07	2.19	49.92	0.002909	197.32	3.56	52.04	0.002849	160.46	4.80
1980 TO 1989		60.09	0.002971	308.72	2.20	50.33	0.002862	195.71	3.54	52.30	0.002789	159.66	4.94
1981 TO 1990		60.27	0.002902	307.76	2.21	50.43	0.002797	197.32	3.53	52.09	0.002718	158.39	4.93
1982 TO 1991		55.49	0.003211	301.87	2.28	48.70	0.003117	200.20	3.55	49.90	0.003081	165.35	4.49
1983 TO 1992		58.98	0.002860	312.81	2.13	49.81	0.002761	199.74	3.71	50.29	0.002710	164.05	4.53
1984 TO 1993		61.84	0.002628	317.74	2.05	50.74	0.002534	200.06	3.75	50.70	0.002471	160.75	4.55
1985 TO 1994		52.36	0.003608	333.28	1.85	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1986 TO 1995		52.77	0.002952	332.57	1.85	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1987 TO 1996		54.29	0.002817	334.29	1.84	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1988 TO 1997		60.13	0.002392	338.41	1.78	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1989 TO 1998		58.48	0.002385	371.94	1.36	0.00	0.000000	0.00	0.00	56.56	0.002412	230.74	1.73
1990 TO 1999		62.14	0.002306	391.83	1.16	0.00	0.000000	0.00	0.00	59.29	0.002335	235.27	1.62
1991 TO 2000		66.52	0.002195	393.14	1.14	0.00	0.000000	0.00	0.00	63.75	0.002221	231.38	1.64
1992 TO 2001		72.19	0.002041	399.64	1.07	0.00	0.000000	0.00	0.00	65.02	0.002064	214.56	1.85
1993 TO 2002		76.71	0.001989	408.67	0.99	0.00	0.000000	0.00	0.00	72.14	0.002013	223.88	1.67
1994 TO 2003		83.08	0.001867	419.48	0.89	0.00	0.000000	0.00	0.00	142.81	0.001891	218.12	0.61
1995 TO 2004		0.00	0.000000	0.00	0.00	75.41	0.001149	216.82	2.55	0.00	0.000000	0.00	0.00
1996 TO 2005		0.00	0.000000	0.00	0.00	79.13	0.001322	211.68	2.63	0.00	0.000000	0.00	0.00
1997 TO 2006		0.00	0.000000	0.00	0.00	73.17	0.001136	211.15	2.64	0.00	0.000000	0.00	0.00
1998 TO 2007		0.00	0.000000	0.00	0.00	75.58	0.001111	212.35	2.63	0.00	0.000000	0.00	0.00

ORANGE AND ROCKLAND UTILITIES INC. MORTALITY STUDY BY LEAST SQUARE FITTING OF WEIGHTED RETIREMENT RATIOS
ACCOUNT 2375000 STRUCTURES AND IMPROVEMENTS PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2007

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
2007 TO 2007	2007 TO 2007	399.00	0.000000	99.87	5.10	399.00	0.000000	99.87	5.10	399.00	0.000000	99.87	5.10
2006 TO 2007	2006 TO 2007	101.09	0.002446	324.94	1.97	77.18	0.002457	219.62	3.22	0.00	0.000000	0.00	0.00
2005 TO 2007	2005 TO 2007	119.25	0.000858	329.99	1.90	85.52	0.000857	221.59	3.16	0.00	0.000000	0.00	0.00
2004 TO 2007	2004 TO 2007	132.44	0.000761	300.90	1.88	91.58	0.000761	222.22	3.13	0.00	0.000000	0.00	0.00
2003 TO 2007	2003 TO 2007	143.70	0.000630	277.31	1.86	96.24	0.000630	222.89	3.11	0.00	0.000000	0.00	0.00
2002 TO 2007	2002 TO 2007	147.75	0.000604	269.71	1.83	99.89	0.000606	226.74	3.02	0.00	0.000000	0.00	0.00
2001 TO 2007	2001 TO 2007	129.37	0.000684	308.03	1.81	97.23	0.000687	237.06	2.77	0.00	0.000000	0.00	0.00
2000 TO 2007	2000 TO 2007	134.88	0.000643	295.45	1.80	99.85	0.000646	235.86	2.78	0.00	0.000000	0.00	0.00
1999 TO 2007	1999 TO 2007	201.86	0.000791	197.42	1.47	89.80	0.000787	215.47	3.00	0.00	0.000000	0.00	0.00
1998 TO 2007	1998 TO 2007	0.00	0.000000	0.00	0.00	75.58	0.001111	212.35	2.63	0.00	0.000000	0.00	0.00
1997 TO 2007	1997 TO 2007	0.00	0.000000	0.00	0.00	77.31	0.001037	212.79	2.69	0.00	0.000000	0.00	0.00
1996 TO 2007	1996 TO 2007	0.00	0.000000	0.00	0.00	78.47	0.001001	213.47	2.71	0.00	0.000000	0.00	0.00
1995 TO 2007	1995 TO 2007	227.16	0.000909	175.42	1.05	78.52	0.000897	217.13	2.69	0.00	0.000000	0.00	0.00
1994 TO 2007	1994 TO 2007	103.77	0.001386	384.02	1.03	97.78	0.001395	346.17	1.29	0.00	0.000000	0.00	0.00
1993 TO 2007	1993 TO 2007	104.44	0.001339	381.57	1.08	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1992 TO 2007	1992 TO 2007	104.72	0.001300	380.54	1.13	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1991 TO 2007	1991 TO 2007	96.57	0.001340	385.73	1.23	95.53	0.001349	372.15	1.28	0.00	0.000000	0.00	0.00
1990 TO 2007	1990 TO 2007	96.45	0.001323	384.15	1.24	93.54	0.001331	351.19	1.38	0.00	0.000000	0.00	0.00
1989 TO 2007	1989 TO 2007	97.42	0.001304	383.40	1.25	93.17	0.001312	340.77	1.44	0.00	0.000000	0.00	0.00
1988 TO 2007	1988 TO 2007	95.01	0.001297	380.48	1.28	88.53	0.001306	320.25	1.57	0.00	0.000000	0.00	0.00
1987 TO 2007	1987 TO 2007	88.37	0.001344	371.73	1.37	73.03	0.001350	262.22	2.11	68.13	0.001358	212.10	2.49
1986 TO 2007	1986 TO 2007	88.84	0.001332	370.90	1.38	73.32	0.001338	261.19	2.11	68.71	0.001346	213.22	2.48
1985 TO 2007	1985 TO 2007	89.26	0.001318	371.38	1.38	73.59	0.001324	261.57	2.12	69.24	0.001333	215.93	2.46
1984 TO 2007	1984 TO 2007	83.42	0.001394	363.82	1.47	67.25	0.001395	246.08	2.34	63.53	0.001402	199.11	2.74
1983 TO 2007	1983 TO 2007	83.99	0.001377	363.72	1.47	67.62	0.001379	246.23	2.34	63.93	0.001386	201.01	2.74
1982 TO 2007	1982 TO 2007	84.47	0.001365	362.86	1.48	67.95	0.001367	246.49	2.34	64.27	0.001374	201.49	2.73
1981 TO 2007	1981 TO 2007	84.92	0.001352	363.27	1.48	68.24	0.001354	245.45	2.35	64.58	0.001361	202.07	2.73
1980 TO 2007	1980 TO 2007	85.32	0.001314	362.75	1.48	68.51	0.001316	245.97	2.35	64.85	0.001322	201.22	2.73
1979 TO 2007	1979 TO 2007	85.67	0.001297	362.44	1.48	68.75	0.001299	246.53	2.35	65.09	0.001305	202.03	2.73
1978 TO 2007	1978 TO 2007	85.97	0.001283	362.32	1.49	68.99	0.001285	245.68	2.35	65.29	0.001292	201.39	2.74
1977 TO 2007	1977 TO 2007	86.18	0.001274	361.44	1.49	69.16	0.001276	246.52	2.36	65.44	0.001282	202.49	2.74

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. 2007
ACCOUNT 2376000 MAINS
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	367.43	1.43	0.00	0.000000	0.00	0.00	98.71	0.000292	209.21	1.95
1953 TO 1962	1953 TO 1962	98.36	0.000251	368.56	1.41	0.00	0.000000	0.00	0.00	94.72	0.000234	202.17	2.10
1954 TO 1963	1954 TO 1963	87.73	0.000382	364.16	1.46	0.00	0.000000	0.00	0.00	110.80	0.000368	208.94	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	358.53	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	1.84	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	1.87	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	335.38	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	328.55	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	74.04	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	83.37	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	238.65	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	2.80	0.00	0.000000	0.00	0.00
1996 TO 2005	1996 TO 2005	79.35	0.000400	334.58	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
1998 TO 2007	1998 TO 2007	77.43	0.000415	335.14	1.82	65.81	0.000340	222.62	2.94	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. 2007

ACCOUNT 2376000 MAINS

SUMMARY OF SHRINKING BANDS

		FIRST DEGREE				SECOND DEGREE				THIRD DEGREE			
YEAR	YEAR	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
2007 TO 2007	2007 TO 2007	92.70	0.001044	340.35	1.76	65.74	0.000905	193.95	3.61	67.03	0.000822	164.86	4.28
2006 TO 2007	2006 TO 2007	79.76	0.000755	337.88	1.79	65.02	0.000655	206.86	3.30	64.57	0.000618	183.51	3.41
2005 TO 2007	2005 TO 2007	81.63	0.000627	335.07	1.83	66.54	0.000536	209.65	3.31	66.02	0.000512	187.07	3.44
2004 TO 2007	2004 TO 2007	79.29	0.000616	333.57	1.84	65.99	0.000534	211.39	3.23	65.54	0.000520	193.02	3.32
2003 TO 2007	2003 TO 2007	76.72	0.000550	331.73	1.88	65.19	0.000458	213.99	3.22	64.91	0.000451	197.97	3.28
2002 TO 2007	2002 TO 2007	78.07	0.000505	332.38	1.87	66.05	0.000425	215.74	3.14	65.82	0.000423	204.36	3.20
2001 TO 2007	2001 TO 2007	78.67	0.000475	334.94	1.83	66.26	0.000399	218.09	3.04	66.08	0.000400	211.10	3.08
2000 TO 2007	2000 TO 2007	77.47	0.000451	334.96	1.84	65.90	0.000379	220.79	2.99	0.00	0.000000	0.00	0.00
1999 TO 2007	1999 TO 2007	77.69	0.000439	335.31	1.82	65.85	0.000364	220.96	2.97	0.00	0.000000	0.00	0.00
1998 TO 2007	1998 TO 2007	77.43	0.000415	335.14	1.82	65.81	0.000340	222.62	2.94	0.00	0.000000	0.00	0.00
1997 TO 2007	1997 TO 2007	78.44	0.000397	335.93	1.82	66.37	0.000325	223.74	2.94	0.00	0.000000	0.00	0.00
1996 TO 2007	1996 TO 2007	79.45	0.000387	335.44	1.82	66.91	0.000317	223.44	2.94	0.00	0.000000	0.00	0.00
1995 TO 2007	1995 TO 2007	79.71	0.000382	335.59	1.83	67.04	0.000311	222.99	2.95	0.00	0.000000	0.00	0.00
1994 TO 2007	1994 TO 2007	80.28	0.000368	334.54	1.83	67.42	0.000300	224.71	2.94	0.00	0.000000	0.00	0.00
1993 TO 2007	1993 TO 2007	80.26	0.000358	334.54	1.83	67.51	0.000292	224.40	2.92	0.00	0.000000	0.00	0.00
1992 TO 2007	1992 TO 2007	80.46	0.000349	334.93	1.84	67.69	0.000285	225.30	2.91	0.00	0.000000	0.00	0.00
1991 TO 2007	1991 TO 2007	80.51	0.000342	334.73	1.84	67.75	0.000279	226.57	2.91	0.00	0.000000	0.00	0.00
1990 TO 2007	1990 TO 2007	79.42	0.000331	334.31	1.85	67.34	0.000268	227.93	2.88	0.00	0.000000	0.00	0.00
1989 TO 2007	1989 TO 2007	78.84	0.000330	332.97	1.85	67.02	0.000264	227.53	2.88	0.00	0.000000	0.00	0.00
1988 TO 2007	1988 TO 2007	79.32	0.000324	333.47	1.85	67.32	0.000260	228.02	2.87	0.00	0.000000	0.00	0.00
1987 TO 2007	1987 TO 2007	79.97	0.000321	333.24	1.85	67.67	0.000259	228.31	2.88	0.00	0.000000	0.00	0.00
1986 TO 2007	1986 TO 2007	80.57	0.000317	333.24	1.85	67.99	0.000256	227.24	2.88	0.00	0.000000	0.00	0.00
1985 TO 2007	1985 TO 2007	81.03	0.000312	333.83	1.86	68.26	0.000252	227.79	2.88	0.00	0.000000	0.00	0.00
1984 TO 2007	1984 TO 2007	81.43	0.000307	333.42	1.86	68.49	0.000248	228.50	2.88	0.00	0.000000	0.00	0.00
1983 TO 2007	1983 TO 2007	81.62	0.000304	332.63	1.86	68.59	0.000245	228.16	2.88	0.00	0.000000	0.00	0.00
1982 TO 2007	1982 TO 2007	81.50	0.000302	333.15	1.86	68.53	0.000243	228.35	2.88	0.00	0.000000	0.00	0.00
1981 TO 2007	1981 TO 2007	81.65	0.000298	332.52	1.86	68.65	0.000240	227.97	2.87	0.00	0.000000	0.00	0.00
1980 TO 2007	1980 TO 2007	81.86	0.000294	332.90	1.86	68.78	0.000237	229.00	2.87	0.00	0.000000	0.00	0.00
1979 TO 2007	1979 TO 2007	81.93	0.000291	332.59	1.86	68.85	0.000234	228.76	2.87	0.00	0.000000	0.00	0.00
1978 TO 2007	1978 TO 2007	81.91	0.000289	332.69	1.86	68.83	0.000231	228.82	2.87	0.00	0.000000	0.00	0.00
1977 TO 2007	1977 TO 2007	81.89	0.000287	332.77	1.86	68.83	0.000229	228.84	2.87	0.00	0.000000	0.00	0.00
1976 TO 2007	1976 TO 2007	81.87	0.000285	332.83	1.86	68.84	0.000227	228.81	2.87	0.00	0.000000	0.00	0.00
1975 TO 2007	1975 TO 2007	81.88	0.000283	332.79	1.86	68.83	0.000226	228.81	2.86	0.00	0.000000	0.00	0.00
1974 TO 2007	1974 TO 2007	81.90	0.000280	332.72	1.86	68.86	0.000224	228.72	2.86	0.00	0.000000	0.00	0.00
1973 TO 2007	1973 TO 2007	80.96	0.000281	334.12	1.85	68.46	0.000226	230.07	2.82	0.00	0.000000	0.00	0.00
1972 TO 2007	1972 TO 2007	80.87	0.000278	333.25	1.85	68.49	0.000234	231.42	2.81	0.00	0.000000	0.00	0.00
1971 TO 2007	1971 TO 2007	80.64	0.000275	334.19	1.85	68.46	0.000222	231.52	2.80	0.00	0.000000	0.00	0.00
1970 TO 2007	1970 TO 2007	80.55	0.000273	334.57	1.85	68.46	0.000221	232.98	2.78	0.00	0.000000	0.00	0.00
1969 TO 2007	1969 TO 2007	80.58	0.000272	334.46	1.84	68.46	0.000220	232.99	2.77	0.00	0.000000	0.00	0.00
1968 TO 2007	1968 TO 2007	80.57	0.000270	334.48	1.84	68.49	0.000219	232.89	2.76	0.00	0.000000	0.00	0.00
1967 TO 2007	1967 TO 2007	80.54	0.000269	334.64	1.83	68.48	0.000219	232.92	2.75	0.00	0.000000	0.00	0.00
1966 TO 2007	1966 TO 2007	80.60	0.000268	335.61	1.83	68.52	0.000218	232.79	2.75	0.00	0.000000	0.00	0.00
1965 TO 2007	1965 TO 2007	80.58	0.000267	335.67	1.83	68.53	0.000217	234.19	2.75	0.00	0.000000	0.00	0.00
1964 TO 2007	1964 TO 2007	80.53	0.000267	335.90	1.83	68.53	0.000217	234.20	2.74	0.00	0.000000	0.00	0.00
1963 TO 2007	1963 TO 2007	80.50	0.000266	336.03	1.83	68.54	0.000217	234.19	2.74	0.00	0.000000	0.00	0.00
1962 TO 2007	1962 TO 2007	80.54	0.000265	335.86	1.82	68.56	0.000216	234.11	2.74	0.00	0.000000	0.00	0.00
1961 TO 2007	1961 TO 2007	80.58	0.000265	335.70	1.82	68.59	0.000216	234.01	2.73	0.00	0.000000	0.00	0.00
1960 TO 2007	1960 TO 2007	80.63	0.000264	335.50	1.82	68.61	0.000215	233.93	2.73	0.00	0.000000	0.00	0.00
1959 TO 2007	1959 TO 2007	80.66	0.000263	335.36	1.82	68.63	0.000215	233.88	2.73	0.00	0.000000	0.00	0.00
1958 TO 2007	1958 TO 2007	80.69	0.000263	336.47	1.82	68.65	0.000214	233.80	2.73	0.00	0.000000	0.00	0.00
1957 TO 2007	1957 TO 2007	80.73	0.000263	336.30	1.82	68.67	0.000214	235.18	2.73	0.00	0.000000	0.00	0.00
1956 TO 2007	1956 TO 2007	80.72	0.000262	336.36	1.82	68.68	0.000214	235.16	2.73	0.00	0.000000	0.00	0.00
1955 TO 2007	1955 TO 2007	80.71	0.000262	336.38	1.82	68.68	0.000214	235.16	2.72	0.00	0.000000	0.00	0.00

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. 2007

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)	AVERAGE SERVICE LIFE (YEARS)	FIT INDEX		TERMINAL A/L RATIO (PERCENT)
1954 TO 2007		80.73	0.000262	336.33	1.82	68.68	0.000213	235.16	2.72	0.00	0.000000	0.00
1953 TO 2007		80.75	0.000261	336.21	1.82	68.69	0.000213	235.11	2.72	0.00	0.000000	0.00
1952 TO 2007		80.75	0.000261	336.20	1.82	68.70	0.000213	235.10	2.72	0.00	0.000000	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. 2007
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	0.002066	483.88	0.32	0.00	0.000000	0.00	0.00	45.38	0.002061	263.31	0.54
1953 TO 1962	1953 TO 1962	66.01	0.001472	603.72	-1.54	0.00	0.000000	0.00	0.00	52.30	0.001469	203.61	1.39
1954 TO 1963	1954 TO 1963	54.77	0.001396	539.53	-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	553.09	-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	515.02	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	552.95	-0.27	59.79	0.001147	398.92	0.46	54.02	0.001123	193.46	1.79
1958 TO 1967	1958 TO 1967	38.88	0.002558	420.56	0.86	0.00	0.000000	0.00	0.00	43.79	0.002569	282.04	0.69
1959 TO 1968	1959 TO 1968	41.17	0.002040	416.53	0.90	0.00	0.000000	0.00	0.00	46.42	0.002045	276.83	0.93
1960 TO 1969	1960 TO 1969	45.27	0.001610	403.18	1.04	0.00	0.000000	0.00	0.00	51.04	0.001614	275.27	0.93
1961 TO 1970	1961 TO 1970	43.31	0.001400	419.04	0.89	0.00	0.000000	0.00	0.00	50.01	0.001380	262.92	0.85
1962 TO 1971	1962 TO 1971	33.66	0.003958	375.86	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	387.46	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	381.69	1.26	0.00	0.000000	0.00	0.00	35.41	0.002117	306.41	1.32
1965 TO 1974	1965 TO 1974	34.05	0.002098	362.72	1.45	0.00	0.000000	0.00	0.00	37.18	0.002214	361.76	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	348.53	1.63	39.16	0.001975	320.51	0.00	0.00	0.000000	0.00	0.00
1968 TO 1977	1968 TO 1977	40.03	0.001964	358.49	1.51	37.65	0.001899	343.99	1.58	37.73	0.001912	316.76	1.60
1969 TO 1978	1969 TO 1978	37.87	0.001887	357.83	1.53	37.39	0.001839	357.00	1.52	37.49	0.001851	313.41	1.55
1970 TO 1979	1970 TO 1979	37.40	0.001825	356.92	1.52	38.56	0.001666	315.12	1.76	0.00	0.000000	0.00	0.00
1971 TO 1980	1971 TO 1980	39.29	0.001657	349.98	1.62	39.74	0.001507	285.59	1.88	0.00	0.000000	0.00	0.00
1972 TO 1981	1972 TO 1981	42.04	0.001510	357.96	1.52	39.43	0.001569	277.74	1.93	0.00	0.000000	0.00	0.00
1973 TO 1982	1973 TO 1982	42.12	0.001577	357.32	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	363.68	1.46	35.02	0.002267	295.56	1.76	0.00	0.000000	0.00	0.00
1975 TO 1984	1975 TO 1984	36.32	0.002264	359.27	1.50	37.30	0.002070	293.60	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	361.80	1.48	33.66	0.002136	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	32.71	0.002014	279.75	2.05	0.00	0.000000	0.00	0.00
1979 TO 1988	1979 TO 1988	33.47	0.002026	336.09	1.79	27.94	0.002414	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	27.39	0.002423	323.14	1.72	0.00	0.000000	0.00	0.00
1981 TO 1990	1981 TO 1990	27.49	0.002414	347.46	1.66	27.08	0.002339	304.61	1.76	0.00	0.000000	0.00	0.00
1982 TO 1991	1982 TO 1991	27.22	0.002346	347.16	1.64	23.46	0.002538	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	23.44	0.002594	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	23.71	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	24.11	0.002478	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	24.55	0.002462	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	25.47	0.002132	323.92	1.81	0.00	0.000000	0.00	0.00
1988 TO 1997	1988 TO 1997	25.49	0.002119	335.49	1.77	26.51	0.002101	315.01	1.86	0.00	0.000000	0.00	0.00
1989 TO 1998	1989 TO 1998	26.56	0.002091	336.95	1.79	29.07	0.002232	318.18	1.62	0.00	0.000000	0.00	0.00
1990 TO 1999	1990 TO 1999	29.52	0.002224	360.74	1.48	30.51	0.002346	316.33	1.64	0.00	0.000000	0.00	0.00
1991 TO 2000	1991 TO 2000	31.09	0.002336	358.64	1.49	30.53	0.002271	319.34	1.66	0.00	0.000000	0.00	0.00
1992 TO 2001	1992 TO 2001	30.97	0.002260	353.56	1.56	0.00	0.000000	0.00	0.00	34.95	0.001896	258.96	1.30
1993 TO 2002	1993 TO 2002	35.90	0.001887	422.00	0.85	0.00	0.000000	0.00	0.00	38.28	0.001730	265.15	1.12
1994 TO 2003	1994 TO 2003	39.35	0.001721	451.06	0.58	0.00	0.000000	0.00	0.00	37.54	0.001778	328.97	0.96
1995 TO 2004	1995 TO 2004	37.66	0.001758	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	0.002060	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	0.002314	403.39	1.02	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1998 TO 2007	1998 TO 2007	29.42	0.002333	416.43	0.88	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
ACCOUNT 2378000 MEAS. AND REG. EQUIPMENT PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2007
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
2007 TO 2007	2007	31.73	0.006666	508.97	0.10	0.00	0.000000	0.00	0.00	33.10	0.006717	300.58	0.12
2006 TO 2007	2007	28.50	0.004771	415.72	0.90	0.00	0.000000	0.00	0.00	29.60	0.004751	295.58	0.72
2005 TO 2007	2007	24.05	0.004214	417.80	0.88	0.00	0.000000	0.00	0.00	26.52	0.004175	480.70	-0.28
2004 TO 2007	2007	25.63	0.003713	392.19	1.13	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
2003 TO 2007	2007	27.66	0.003178	381.42	1.24	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
2002 TO 2007	2007	26.52	0.003095	431.80	0.74	0.00	0.000000	0.00	0.00	34.23	0.003077	512.77	-2.60
2001 TO 2007	2007	26.97	0.002915	417.12	0.89	0.00	0.000000	0.00	0.00	29.30	0.002911	462.48	0.25
2000 TO 2007	2007	28.18	0.002661	406.30	0.98	0.00	0.000000	0.00	0.00	38.06	0.002652	587.25	-2.60
1999 TO 2007	2007	28.68	0.002560	437.57	0.71	0.00	0.000000	0.00	0.00	50.14	0.002573	794.82	-2.60
1998 TO 2007	2007	29.42	0.002333	416.43	0.88	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1997 TO 2007	2007	30.06	0.002139	414.21	0.91	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1996 TO 2007	2007	30.58	0.001915	416.93	0.91	0.00	0.000000	0.00	0.00	55.22	0.001920	721.61	-2.60
1995 TO 2007	2007	31.20	0.001808	408.62	0.97	0.00	0.000000	0.00	0.00	53.79	0.001809	724.05	-2.60
1994 TO 2007	2007	31.04	0.001714	404.32	1.01	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1993 TO 2007	2007	30.81	0.001612	394.32	1.13	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1992 TO 2007	2007	28.91	0.001590	378.77	1.27	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1991 TO 2007	2007	28.89	0.001564	379.05	1.28	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1990 TO 2007	2007	28.90	0.001508	378.91	1.27	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1989 TO 2007	2007	28.10	0.001509	375.47	1.30	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1988 TO 2007	2007	28.09	0.001446	372.02	1.33	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1987 TO 2007	2007	28.08	0.001443	372.17	1.36	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1986 TO 2007	2007	28.20	0.001419	370.60	1.36	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1985 TO 2007	2007	28.46	0.001392	370.67	1.36	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1984 TO 2007	2007	28.30	0.001416	369.30	1.38	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1983 TO 2007	2007	28.45	0.001399	370.79	1.37	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1982 TO 2007	2007	28.54	0.001394	369.61	1.37	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1981 TO 2007	2007	28.60	0.001399	368.89	1.37	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1980 TO 2007	2007	28.73	0.001387	370.70	1.37	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1979 TO 2007	2007	28.80	0.001371	369.77	1.37	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1978 TO 2007	2007	28.84	0.001355	369.33	1.37	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1977 TO 2007	2007	28.92	0.001349	371.74	1.37	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1976 TO 2007	2007	29.02	0.001332	370.48	1.37	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1975 TO 2007	2007	29.07	0.001314	369.83	1.38	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1974 TO 2007	2007	29.11	0.001312	369.29	1.39	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1973 TO 2007	2007	29.16	0.001307	368.65	1.39	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1972 TO 2007	2007	29.18	0.001300	368.40	1.39	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1971 TO 2007	2007	29.11	0.001297	369.24	1.39	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1970 TO 2007	2007	29.12	0.001293	369.11	1.39	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1969 TO 2007	2007	29.17	0.001292	368.51	1.39	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1968 TO 2007	2007	29.21	0.001289	367.97	1.39	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1967 TO 2007	2007	29.18	0.001289	368.39	1.39	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1966 TO 2007	2007	29.22	0.001286	367.95	1.39	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1965 TO 2007	2007	29.22	0.001283	367.87	1.38	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1964 TO 2007	2007	29.25	0.001281	367.57	1.39	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1963 TO 2007	2007	29.26	0.001278	367.41	1.39	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1962 TO 2007	2007	29.28	0.001276	367.15	1.39	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1961 TO 2007	2007	29.29	0.001275	367.05	1.39	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1960 TO 2007	2007	29.30	0.001274	370.29	1.39	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1959 TO 2007	2007	29.29	0.001274	370.38	1.38	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1958 TO 2007	2007	29.30	0.001273	370.27	1.38	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1957 TO 2007	2007	29.31	0.001272	370.14	1.38	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1956 TO 2007	2007	29.32	0.001272	370.09	1.38	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1955 TO 2007	2007	29.31	0.001272	370.13	1.38	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
ACCOUNT 2378000 MEAS. AND REG. EQUIPMENT PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2007
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)
1954 TO 2007		29.32	0.001269	370.11	1.38	0.00	0.000000	0.00	0.00	0.00
1953 TO 2007		29.32	0.001268	370.05	1.38	0.00	0.000000	0.00	0.00	0.00
1952 TO 2007		29.32	0.001268	370.11	1.38	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. 2007

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	55.21	0.000432	352.26	1.59	48.75	0.000341	238.99	2.50	47.01	0.000297	196.77	2.78
1953 TO 1962	1953 TO 1962	53.75	0.000439	354.39	1.58	48.04	0.000362	242.49	2.44	46.73	0.000340	204.38	2.67
1954 TO 1963	1954 TO 1963	52.25	0.000393	353.08	1.59	47.34	0.000320	248.21	2.35	46.12	0.000290	207.06	2.60
1955 TO 1964	1955 TO 1964	51.77	0.000335	350.58	1.63	47.44	0.000273	254.00	2.30	46.41	0.000255	214.39	2.53
1956 TO 1965	1956 TO 1965	49.59	0.000299	349.83	1.64	46.35	0.000252	264.31	2.18	45.66	0.000246	231.07	2.35
1957 TO 1966	1957 TO 1966	49.21	0.000270	348.49	1.65	46.45	0.000239	274.50	2.09	45.94	0.000238	244.87	2.21
1958 TO 1967	1958 TO 1967	48.09	0.000243	348.29	1.65	46.12	0.000227	289.44	1.97	0.00	0.000000	0.00	0.00
1959 TO 1968	1959 TO 1968	50.32	0.000229	348.79	1.65	48.12	0.000219	291.95	1.95	0.00	0.000000	0.00	0.00
1960 TO 1969	1960 TO 1969	47.27	0.000276	345.89	1.68	47.20	0.000279	342.19	1.69	0.00	0.000000	0.00	0.00
1961 TO 1970	1961 TO 1970	43.62	0.000357	342.76	1.76	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	339.12	1.82	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1963 TO 1972	1963 TO 1972	35.81	0.000663	333.71	1.85	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	332.30	1.84	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1965 TO 1974	1965 TO 1974	32.81	0.000815	333.72	1.81	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	335.15	1.83	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1967 TO 1976	1967 TO 1976	33.39	0.000727	333.90	1.84	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	333.12	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	333.93	1.83	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	333.51	1.81	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	334.01	1.83	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	336.08	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	339.60	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	340.22	1.75	48.90	0.000276	318.02	1.86	0.00	0.000000	0.00	0.00
1975 TO 1984	1975 TO 1984	54.37	0.000230	341.21	1.75	52.19	0.000232	301.80	1.96	0.00	0.000000	0.00	0.00
1976 TO 1985	1976 TO 1985	57.56	0.000209	339.62	1.76	54.28	0.000210	290.16	2.05	0.00	0.000000	0.00	0.00
1977 TO 1986	1977 TO 1986	63.39	0.000198	343.09	1.73	58.40	0.000197	283.40	2.09	0.00	0.000000	0.00	0.00
1978 TO 1987	1978 TO 1987	72.00	0.000174	346.53	1.69	64.32	0.000171	277.52	2.13	0.00	0.000000	0.00	0.00
1979 TO 1988	1979 TO 1988	74.42	0.000176	347.33	1.67	62.57	0.000163	259.73	2.30	0.00	0.000000	0.00	0.00
1980 TO 1989	1980 TO 1989	75.46	0.000176	347.85	1.66	62.40	0.000160	255.62	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	245.91	2.49	0.00	0.000000	0.00	0.00
1982 TO 1991	1982 TO 1991	82.72	0.000187	351.18	1.63	63.54	0.000159	244.72	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	240.70	2.54	0.00	0.000000	0.00	0.00
1984 TO 1993	1984 TO 1993	83.02	0.000245	348.69	1.65	61.86	0.000210	236.83	2.63	0.00	0.000000	0.00	0.00
1985 TO 1994	1985 TO 1994	80.63	0.000282	346.66	1.68	59.78	0.000235	231.69	2.71	0.00	0.000000	0.00	0.00
1986 TO 1995	1986 TO 1995	85.05	0.000255	348.60	1.66	61.69	0.000209	230.99	2.72	0.00	0.000000	0.00	0.00
1987 TO 1996	1987 TO 1996	86.56	0.000231	348.32	1.66	62.88	0.000186	230.29	2.75	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	230.29	2.78	0.00	0.000000	0.00	0.00
1989 TO 1998	1989 TO 1998	92.96	0.000215	348.01	1.67	65.78	0.000173	228.78	2.78	0.00	0.000000	0.00	0.00
1990 TO 1999	1990 TO 1999	90.09	0.000245	357.96	1.54	63.61	0.000198	231.88	2.65	0.00	0.000000	0.00	0.00
1991 TO 2000	1991 TO 2000	88.63	0.000252	354.83	1.58	63.76	0.000208	231.32	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	228.32	2.74	0.00	0.000000	0.00	0.00
1993 TO 2002	1993 TO 2002	92.93	0.000237	350.27	1.64	65.82	0.000190	227.13	2.78	0.00	0.000000	0.00	0.00
1994 TO 2003	1994 TO 2003	100.25	0.000204	353.62	1.60	69.54	0.000166	229.36	2.75	0.00	0.000000	0.00	0.00
1995 TO 2004	1995 TO 2004	105.24	0.000196	353.94	1.60	71.52	0.000159	228.60	2.78	70.66	0.000160	217.23	2.87
1996 TO 2005	1996 TO 2005	101.10	0.000196	348.66	1.66	69.82	0.000147	225.57	2.87	69.27	0.000148	217.26	2.93
1997 TO 2006	1997 TO 2006	99.56	0.000189	346.02	1.66	69.42	0.000130	223.99	2.93	68.90	0.000130	216.99	2.99
1998 TO 2007	1998 TO 2007	96.08	0.000253	341.90	1.75	66.73	0.000179	216.56	3.11	64.35	0.000163	190.35	3.46

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. 2007

SUMMARY OF SHRINKING BANDS

YEAR	YEAR	FIRST DEGREE			SECOND DEGREE			THIRD DEGREE		
		AVERAGE SERVICE LIFE (YEARS)	EQUIV. H CURVE	TERMINAL A/L RATIO (PERCENT)	FIT INDEX	AVERAGE SERVICE LIFE (YEARS)	EQUIV. H CURVE	TERMINAL A/L RATIO (PERCENT)	FIT INDEX	EQUIV. H CURVE
2007	TO 2007	80.23	1.98	324.71	0.000858	58.01	0.000727	197.38	0.000570	162.76
2006	TO 2007	85.49	1.93	328.09	0.000523	61.75	0.000422	204.86	0.000346	171.89
2005	TO 2007	86.36	1.92	328.27	0.000426	62.66	0.000325	206.67	0.000281	176.96
2004	TO 2007	90.53	1.91	329.73	0.000371	64.18	0.000274	208.01	0.000238	177.94
2003	TO 2007	95.72	1.87	332.75	0.000322	66.40	0.000241	210.09	0.000211	179.57
2002	TO 2007	99.20	1.86	333.16	0.000292	67.68	0.000215	210.54	0.000191	180.95
2001	TO 2007	97.74	1.86	333.04	0.000281	67.19	0.000200	210.61	0.000181	182.93
2000	TO 2007	95.56	1.86	333.29	0.000265	66.89	0.000185	213.04	0.000169	186.33
1999	TO 2007	93.59	1.75	341.40	0.000264	65.84	0.000186	216.42	0.000168	189.71
1998	TO 2007	96.08	1.75	341.90	0.000253	66.73	0.000179	216.56	0.000163	190.35
1997	TO 2007	95.71	1.74	342.17	0.000247	66.48	0.000170	217.36	0.000158	191.87
1996	TO 2007	96.02	1.74	342.11	0.000240	66.71	0.000167	218.12	0.000155	192.92
1995	TO 2007	96.80	1.74	343.50	0.000234	66.98	0.000162	218.74	0.000151	193.78
1994	TO 2007	95.47	1.74	341.61	0.000226	66.19	0.000155	218.88	0.000145	194.43
1993	TO 2007	94.41	1.74	342.00	0.000230	66.48	0.000150	219.83	0.000142	197.79
1992	TO 2007	93.97	1.74	343.20	0.000222	66.07	0.000146	220.23	0.000140	199.36
1991	TO 2007	94.29	1.72	343.09	0.000220	66.13	0.000145	220.61	0.000139	199.12
1990	TO 2007	93.98	1.72	343.17	0.000218	65.95	0.000142	220.61	0.000137	200.99
1989	TO 2007	93.46	1.72	344.01	0.000215	65.90	0.000141	222.31	0.000135	201.15
1988	TO 2007	93.05	1.71	344.45	0.000214	65.71	0.000139	221.42	0.000134	201.65
1987	TO 2007	93.53	1.71	344.82	0.000211	65.91	0.000138	222.27	0.000133	201.08
1986	TO 2007	93.66	1.70	345.40	0.000209	65.95	0.000135	222.13	0.000131	202.36
1985	TO 2007	93.40	1.70	345.30	0.000205	65.96	0.000133	223.64	0.000129	203.82
1984	TO 2007	93.41	1.70	345.25	0.000202	66.03	0.000129	223.38	0.000127	203.55
1983	TO 2007	93.04	1.70	345.57	0.000199	66.05	0.000129	223.32	0.000125	203.54
1982	TO 2007	92.68	1.70	345.81	0.000196	66.02	0.000127	224.93	0.000123	205.14
1981	TO 2007	92.35	1.70	345.97	0.000194	65.98	0.000126	225.07	0.000122	205.26
1980	TO 2007	91.98	1.69	346.28	0.000192	65.98	0.000124	225.06	0.000121	205.29
1979	TO 2007	91.64	1.69	346.48	0.000190	65.98	0.000124	226.58	0.000120	205.36
1978	TO 2007	91.16	1.68	346.09	0.000188	65.97	0.000124	226.61	0.000119	205.58
1977	TO 2007	90.52	1.68	347.45	0.000186	65.95	0.000124	228.22	0.000119	205.91
1976	TO 2007	89.91	1.68	347.58	0.000184	65.85	0.000124	228.54	0.000120	206.37
1975	TO 2007	89.62	1.67	347.57	0.000183	65.81	0.000124	230.22	0.000120	206.60
1974	TO 2007	89.21	1.66	348.07	0.000182	65.80	0.000125	230.24	0.000120	206.83
1973	TO 2007	88.08	1.65	349.10	0.000180	65.72	0.000127	232.05	0.000121	206.00
1972	TO 2007	86.91	1.64	350.37	0.000179	65.57	0.000130	234.07	0.000123	206.85
1971	TO 2007	86.55	1.64	349.49	0.000178	65.53	0.000131	235.64	0.000124	207.04
1970	TO 2007	86.18	1.64	349.87	0.000178	65.57	0.000131	235.76	0.000124	205.72
1969	TO 2007	85.92	1.64	349.73	0.000177	65.52	0.000131	235.81	0.000124	205.83
1968	TO 2007	85.91	1.64	349.78	0.000176	65.52	0.000130	235.75	0.000123	207.39
1967	TO 2007	85.81	1.63	350.21	0.000176	65.52	0.000130	235.82	0.000123	205.91
1966	TO 2007	85.74	1.63	350.48	0.000176	65.50	0.000130	235.88	0.000123	205.99
1965	TO 2007	85.64	1.63	350.88	0.000176	65.46	0.000130	236.03	0.000123	206.12
1964	TO 2007	85.55	1.63	350.07	0.000175	65.43	0.000130	236.13	0.000123	206.20
1963	TO 2007	85.51	1.63	350.27	0.000175	65.43	0.000130	236.27	0.000123	206.31
1962	TO 2007	85.46	1.63	350.45	0.000176	65.39	0.000130	236.41	0.000123	206.40
1961	TO 2007	85.42	1.63	350.62	0.000176	65.33	0.000130	236.52	0.000123	206.48
1960	TO 2007	85.41	1.63	350.62	0.000176	65.30	0.000130	236.59	0.000123	206.52
1959	TO 2007	85.38	1.63	350.79	0.000176	65.28	0.000130	236.67	0.000123	206.58
1958	TO 2007	85.34	1.63	350.97	0.000176	65.26	0.000130	236.75	0.000123	206.64
1957	TO 2007	85.31	1.63	351.05	0.000176	65.25	0.000130	236.78	0.000123	206.66
1956	TO 2007	85.30	1.63	351.12	0.000176	65.24	0.000130	236.82	0.000123	206.69
1955	TO 2007	85.29	1.63	351.16	0.000176	65.23	0.000130	236.85	0.000123	206.72

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. 2007

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)	AVERAGE SERVICE LIFE (YEARS)	FIT INDEX	
1954 TO 2007		85.26	0.000176	351.29	1.63	65.21	0.000130	236.94	63.11	0.000123	2.86
1953 TO 2007		85.25	0.000176	351.33	1.63	65.20	0.000130	236.96	63.11	0.000123	2.86
1952 TO 2007		85.24	0.000176	351.38	1.63	65.19	0.000130	237.00	63.10	0.000123	2.86

ORANGE AND ROCKLAND UTILITIES INC. MORTALITY STUDY BY LEAST SQUARE FITTING OF WEIGHTED RETIREMENT RATIOS
ACCOUNT 2381000 METERS PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2007

SUMMARY OF ROLLING BANDS									
FIRST DEGREE					SECOND DEGREE				
YEAR	YEAR	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	24.32	0.002417	302.27	2.23	26.53	0.001994	220.54	3.07	0.000000
1953 TO 1962	23.00	0.002543	302.14	2.26	25.41	0.002042	222.36	3.08	0.000000
1954 TO 1963	21.79	0.002455	300.65	2.23	23.87	0.001998	228.28	2.84	0.000000
1955 TO 1964	20.53	0.002945	304.49	2.18	22.08	0.002619	242.25	2.54	0.000000
1956 TO 1965	20.14	0.002892	305.34	2.21	21.64	0.002530	242.61	2.58	0.000000
1957 TO 1966	20.51	0.002748	304.70	2.20	21.84	0.002309	240.41	2.59	0.000000
1958 TO 1967	20.62	0.002729	303.14	2.23	21.90	0.002055	230.57	2.68	0.000000
1959 TO 1968	21.22	0.002821	299.26	2.26	22.25	0.002018	222.46	2.80	0.000000
1960 TO 1969	22.09	0.002860	301.00	2.25	22.63	0.001981	218.76	2.87	0.000000
1961 TO 1970	21.89	0.002956	299.19	2.25	22.07	0.001747	215.18	2.96	0.000000
1962 TO 1971	23.73	0.002833	301.30	2.24	22.95	0.001646	211.29	3.02	0.001661
1963 TO 1972	23.59	0.002866	303.15	2.25	22.67	0.001905	213.97	3.03	0.000000
1964 TO 1973	24.12	0.002837	300.54	2.27	23.03	0.001993	210.61	3.18	0.000000
1965 TO 1974	25.06	0.002651	301.27	2.28	23.65	0.001783	205.07	3.37	0.000000
1966 TO 1975	25.97	0.002592	302.33	2.27	24.15	0.001768	204.99	3.41	0.000000
1967 TO 1976	26.41	0.002552	301.03	2.30	24.43	0.001656	202.59	3.50	0.000000
1968 TO 1977	28.66	0.001959	305.34	2.17	26.78	0.001326	210.99	3.19	0.000000
1969 TO 1978	29.98	0.001813	308.58	2.16	27.74	0.001254	210.91	3.16	0.000000
1970 TO 1979	31.13	0.001656	309.94	2.11	29.41	0.001103	209.08	3.15	0.000000
1971 TO 1980	34.13	0.001498	312.02	2.09	30.30	0.000954	212.89	3.12	0.000000
1972 TO 1981	35.29	0.001345	315.98	2.05	31.96	0.000974	208.09	3.20	0.000000
1973 TO 1982	38.92	0.001380	317.32	1.99	33.93	0.000899	207.76	3.18	0.000000
1974 TO 1983	42.70	0.001237	322.03	1.98	36.13	0.000758	208.94	3.23	0.000000
1975 TO 1984	46.49	0.001040	323.73	2.04	36.28	0.000842	205.34	3.33	0.000865
1976 TO 1985	46.25	0.001146	318.93	2.07	36.52	0.000855	201.28	3.39	0.000000
1977 TO 1986	46.47	0.001205	317.42	2.12	37.69	0.001013	202.99	3.53	0.001019
1978 TO 1987	47.29	0.001298	314.03	2.14	37.66	0.000964	200.50	3.60	0.000951
1979 TO 1988	47.16	0.001332	310.62	2.13	37.13	0.001108	195.26	3.60	0.001053
1980 TO 1989	47.21	0.001585	312.46	2.17	35.67	0.001430	192.05	3.56	0.001349
1981 TO 1990	44.37	0.002057	309.87	2.20	35.64	0.001419	192.18	3.59	0.001349
1982 TO 1991	43.28	0.002080	308.47	2.20	35.91	0.001384	190.75	3.59	0.001321
1983 TO 1992	42.99	0.002055	308.21	2.23	36.02	0.001357	190.15	3.62	0.001315
1984 TO 1993	42.28	0.002051	303.90	2.23	36.02	0.001555	189.48	3.63	0.001521
1985 TO 1994	39.51	0.002352	299.96	2.29	35.10	0.001554	187.95	3.65	0.001528
1986 TO 1995	38.34	0.002436	298.68	2.31	34.85	0.001465	187.29	3.67	0.001449
1987 TO 1996	38.99	0.002307	301.36	2.29	35.51	0.001465	187.29	3.67	0.001449
1988 TO 1997	39.72	0.002307	303.40	2.25	36.40	0.001254	188.95	3.67	0.001366
1989 TO 1998	37.87	0.002203	299.74	2.28	35.72	0.001358	193.02	3.69	0.001227
1990 TO 1999	38.45	0.001925	300.41	2.28	36.53	0.001210	196.73	3.67	0.001064
1991 TO 2000	40.91	0.001557	304.34	2.23	38.38	0.001051	196.73	3.67	0.000877
1992 TO 2001	43.32	0.001344	308.17	2.19	40.14	0.000990	200.56	3.58	0.000000
1993 TO 2002	40.21	0.001261	307.16	2.21	38.65	0.000846	205.69	3.42	0.000854
1994 TO 2003	41.24	0.001245	306.72	2.21	39.46	0.000870	206.53	3.39	0.000877
1995 TO 2004	33.95	0.002879	298.99	2.29	34.32	0.002541	208.35	3.03	0.000000
1996 TO 2005	35.23	0.002633	302.33	2.27	35.09	0.002357	212.28	2.93	0.000000
1997 TO 2006	33.51	0.002635	299.94	2.29	33.58	0.002199	212.94	2.75	0.000000
1998 TO 2007	33.58	0.002700	299.30	2.31	33.57	0.002274	212.97	2.71	0.000000

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. 2007
ACCOUNT 2381000 METERS
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
2007 TO 2007	2007 TO 2007	44.64	0.006358	308.00	2.17	40.47	0.006262	201.37	2.99	40.51	0.006308	193.78	3.06
2006 TO 2007	2006 TO 2007	32.84	0.005040	296.89	2.34	32.03	0.004494	210.76	2.29	32.34	0.004500	199.45	2.34
2005 TO 2007	2005 TO 2007	36.63	0.003279	301.70	2.27	34.76	0.002805	211.47	2.43	35.07	0.002802	195.34	2.53
2004 TO 2007	2004 TO 2007	28.16	0.005952	289.44	2.45	27.95	0.005601	230.77	2.12	0.00	0.000000	0.00	0.00
2003 TO 2007	2003 TO 2007	30.17	0.004575	290.05	2.42	29.93	0.004182	222.19	2.26	0.00	0.000000	0.00	0.00
2002 TO 2007	2002 TO 2007	30.09	0.003860	294.08	2.40	29.99	0.003463	225.05	2.30	0.00	0.000000	0.00	0.00
2001 TO 2007	2001 TO 2007	31.69	0.003427	295.06	2.35	31.48	0.003052	220.75	2.40	0.00	0.000000	0.00	0.00
2000 TO 2007	2000 TO 2007	33.06	0.003103	297.97	2.31	32.74	0.002735	218.42	2.50	0.00	0.000000	0.00	0.00
1999 TO 2007	1999 TO 2007	33.79	0.002854	300.36	2.29	33.46	0.002475	216.68	2.59	0.00	0.000000	0.00	0.00
1998 TO 2007	1998 TO 2007	33.58	0.002700	299.30	2.31	33.57	0.002274	212.97	2.71	0.00	0.000000	0.00	0.00
1997 TO 2007	1997 TO 2007	34.25	0.002547	302.17	2.28	34.12	0.002112	212.48	2.76	0.00	0.000000	0.00	0.00
1996 TO 2007	1996 TO 2007	34.70	0.002430	301.13	2.28	34.53	0.001969	209.96	2.83	0.00	0.000000	0.00	0.00
1995 TO 2007	1995 TO 2007	34.61	0.002384	301.95	2.29	34.55	0.001910	209.82	2.90	0.00	0.000000	0.00	0.00
1994 TO 2007	1994 TO 2007	34.46	0.002368	300.38	2.30	34.51	0.001883	207.17	2.95	0.00	0.000000	0.00	0.00
1993 TO 2007	1993 TO 2007	34.69	0.002320	301.20	2.30	34.71	0.001823	206.01	3.00	0.00	0.000000	0.00	0.00
1992 TO 2007	1992 TO 2007	34.91	0.002284	299.33	2.30	34.85	0.001775	205.17	3.03	0.00	0.000000	0.00	0.00
1991 TO 2007	1991 TO 2007	35.06	0.002239	300.89	2.30	34.96	0.001716	204.49	3.07	0.00	0.000000	0.00	0.00
1990 TO 2007	1990 TO 2007	35.07	0.002231	300.82	2.30	34.93	0.001682	204.67	3.09	0.00	0.000000	0.00	0.00
1989 TO 2007	1989 TO 2007	35.25	0.002223	299.32	2.30	35.01	0.001652	204.23	3.10	35.09	0.001628	203.74	3.13
1988 TO 2007	1988 TO 2007	35.40	0.002196	300.88	2.30	35.09	0.001616	203.74	3.13	35.22	0.001608	200.15	3.17
1987 TO 2007	1987 TO 2007	35.62	0.002184	298.96	2.30	35.21	0.001596	203.06	3.16	35.25	0.001576	200.02	3.18
1986 TO 2007	1986 TO 2007	35.71	0.002155	301.04	2.30	35.24	0.001564	202.91	3.17	35.26	0.001550	199.95	3.19
1985 TO 2007	1985 TO 2007	35.77	0.002129	300.50	2.30	35.25	0.001538	202.84	3.18	35.26	0.001531	199.53	3.21
1984 TO 2007	1984 TO 2007	35.94	0.002113	299.08	2.30	35.32	0.001519	202.44	3.19	35.33	0.001514	199.26	3.22
1983 TO 2007	1983 TO 2007	36.07	0.002097	300.79	2.29	35.36	0.001503	202.20	3.20	35.38	0.001507	199.12	3.24
1982 TO 2007	1982 TO 2007	36.15	0.002088	300.11	2.29	35.38	0.001495	202.08	3.21	35.41	0.001491	198.91	3.25
1981 TO 2007	1981 TO 2007	36.25	0.002073	299.33	2.29	35.42	0.001479	201.89	3.22	35.44	0.001475	198.83	3.26
1980 TO 2007	1980 TO 2007	36.31	0.002058	301.55	2.30	35.43	0.001463	201.82	3.23	35.46	0.001459	198.91	3.26
1979 TO 2007	1979 TO 2007	36.34	0.002039	301.35	2.30	35.42	0.001447	201.89	3.23	35.44	0.001444	199.04	3.26
1978 TO 2007	1978 TO 2007	36.34	0.002021	301.32	2.30	35.39	0.001432	202.01	3.23	35.42	0.001429	199.34	3.23
1977 TO 2007	1977 TO 2007	36.37	0.002011	301.07	2.29	35.35	0.001417	202.27	3.21	35.37	0.001414	199.55	3.23
1976 TO 2007	1976 TO 2007	36.33	0.001991	301.40	2.29	35.31	0.001403	202.46	3.21	35.33	0.001401	199.77	3.22
1975 TO 2007	1975 TO 2007	36.29	0.001974	301.71	2.28	35.28	0.001391	202.68	3.20	35.29	0.001401	199.77	3.22
1974 TO 2007	1974 TO 2007	36.24	0.001958	302.19	2.28	35.22	0.001380	203.04	3.19	35.22	0.001390	200.16	3.20
1973 TO 2007	1973 TO 2007	36.15	0.001937	302.87	2.27	35.15	0.001369	203.42	3.17	35.15	0.001379	200.59	3.19
1972 TO 2007	1972 TO 2007	36.02	0.001910	301.20	2.26	35.03	0.001356	204.08	3.16	35.03	0.001366	201.25	3.16
1971 TO 2007	1971 TO 2007	36.06	0.001902	303.69	2.26	35.06	0.001349	203.95	3.16	35.05	0.001359	201.11	3.17
1970 TO 2007	1970 TO 2007	35.95	0.001881	301.80	2.26	34.97	0.001340	204.46	3.14	34.97	0.001343	201.72	3.15
1969 TO 2007	1969 TO 2007	35.93	0.001872	301.95	2.25	34.95	0.001334	204.57	3.13	34.92	0.001337	201.87	3.15
1968 TO 2007	1968 TO 2007	35.89	0.001864	302.28	2.25	34.93	0.001328	204.71	3.13	34.92	0.001329	202.20	3.15
1967 TO 2007	1967 TO 2007	35.81	0.001858	302.95	2.25	34.87	0.001320	205.05	3.13	34.87	0.001326	202.36	3.14
1966 TO 2007	1966 TO 2007	35.80	0.001856	303.07	2.25	34.84	0.001317	205.21	3.12	34.84	0.001322	202.59	3.13
1965 TO 2007	1965 TO 2007	35.76	0.001851	303.43	2.24	34.80	0.001313	205.44	3.11	34.80	0.001324	203.19	3.10
1964 TO 2007	1964 TO 2007	35.69	0.001855	304.00	2.23	34.70	0.001315	206.05	3.07	34.70	0.001321	203.59	3.08
1963 TO 2007	1963 TO 2007	35.63	0.001853	304.50	2.22	34.63	0.001312	206.45	3.06	34.63	0.001320	203.77	3.08
1962 TO 2007	1962 TO 2007	35.57	0.001853	305.00	2.22	34.60	0.001312	206.64	3.06	34.60	0.001318	203.93	3.08
1961 TO 2007	1961 TO 2007	35.52	0.001851	305.44	2.22	34.57	0.001310	206.80	3.06	34.57	0.001314	204.05	3.08
1960 TO 2007	1960 TO 2007	35.48	0.001847	305.81	2.22	34.55	0.001306	206.92	3.06	34.55	0.001314	204.18	3.08
1959 TO 2007	1959 TO 2007	35.43	0.001846	306.20	2.22	34.53	0.001305	207.05	3.06	34.53	0.001313	204.35	3.08
1958 TO 2007	1958 TO 2007	35.38	0.001843	306.67	2.22	34.50	0.001303	207.22	3.06	34.50	0.001312	204.54	3.08
1957 TO 2007	1957 TO 2007	35.32	0.001841	304.36	2.22	34.47	0.001301	207.41	3.06	34.47	0.001310	204.62	3.08
1956 TO 2007	1956 TO 2007	35.29	0.001840	304.61	2.22	34.46	0.001301	207.50	3.06	34.45	0.001310	204.62	3.08
1955 TO 2007	1955 TO 2007	35.29	0.001838	304.61	2.22	34.46	0.001298	207.49	3.07	34.46	0.001307	204.61	3.08

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)
1954 TO 2007	1954 TO 2007	35.30	0.001836	304.49	2.22	34.47	0.001297	207.43	3.07	34.47	0.001306	204.55	3.08
	1953 TO 2007	35.32	0.001836	304.40	2.22	34.48	0.001296	207.39	3.07	34.47	0.001305	204.51	3.08
	1952 TO 2007	35.33	0.001836	304.31	2.22	34.48	0.001296	207.36	3.07	34.48	0.001305	204.48	3.08

ORANGE AND ROCKLAND UTILITIES INC. MORTALITY STUDY BY LEAST SQUARE FITTING OF WEIGHTED RETIREMENT RATIOS
ACCOUNT 2382000 METER INSTALLATIONS PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2007

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	1975 TO 1984	28.79	0.005450	300.40	2.29	25.34	0.004734	187.42	3.68	0.00	0.000000	0.00	0.00
1976 TO 1985	1976 TO 1985	28.73	0.005865	294.13	2.36	25.18	0.005064	184.68	3.86	0.00	0.000000	0.00	0.00
1977 TO 1986	1977 TO 1986	29.54	0.005305	296.20	2.33	25.47	0.004547	182.55	3.89	0.00	0.000000	0.00	0.00
1978 TO 1987	1978 TO 1987	30.57	0.004537	299.27	2.29	25.85	0.003737	183.79	3.89	25.87	0.003760	183.61	3.92
1979 TO 1988	1979 TO 1988	32.90	0.003600	305.46	2.23	27.03	0.002975	186.81	3.92	27.08	0.002985	182.78	3.99
1980 TO 1989	1980 TO 1989	36.63	0.002877	309.81	2.15	28.88	0.002452	188.71	3.89	28.90	0.002471	181.66	4.04
1981 TO 1990	1981 TO 1990	38.97	0.002551	311.78	2.12	30.18	0.002212	190.52	3.85	30.12	0.002227	180.94	4.14
1982 TO 1991	1982 TO 1991	41.18	0.002290	314.48	2.10	31.55	0.002030	194.90	3.81	31.35	0.002044	180.25	4.21
1983 TO 1992	1983 TO 1992	47.05	0.001774	319.90	2.04	34.45	0.001607	195.94	3.73	33.79	0.001615	176.09	4.31
1984 TO 1993	1984 TO 1993	50.83	0.001448	321.64	2.01	36.66	0.001321	200.49	3.67	35.86	0.001331	182.67	4.12
1985 TO 1994	1985 TO 1994	58.49	0.000935	325.68	1.96	40.58	0.000843	205.76	3.55	40.29	0.000850	199.79	3.64
1986 TO 1995	1986 TO 1995	69.42	0.000572	330.62	1.89	46.05	0.000514	211.71	3.39	0.00	0.000000	0.00	0.00
1987 TO 1996	1987 TO 1996	81.63	0.000435	333.84	1.84	51.51	0.000399	214.52	3.31	0.00	0.000000	0.00	0.00
1988 TO 1997	1988 TO 1997	91.36	0.000363	336.56	1.82	56.38	0.000341	217.28	3.23	0.00	0.000000	0.00	0.00
1989 TO 1998	1989 TO 1998	103.93	0.000311	339.18	1.78	62.29	0.000299	219.15	3.15	0.00	0.000000	0.00	0.00
1990 TO 1999	1990 TO 1999	112.17	0.000254	340.10	1.77	69.02	0.000248	225.29	3.01	0.00	0.000000	0.00	0.00
1991 TO 2000	1991 TO 2000	147.51	0.000183	270.15	1.72	83.19	0.000181	229.00	2.93	0.00	0.000000	0.00	0.00
1992 TO 2001	1992 TO 2001	167.59	0.000149	237.78	1.71	97.18	0.000149	235.12	2.79	0.00	0.000000	0.00	0.00
1993 TO 2002	1993 TO 2002	171.11	0.000137	232.89	1.64	125.08	0.000138	260.23	2.32	0.00	0.000000	0.00	0.00
1994 TO 2003	1994 TO 2003	216.77	0.000111	183.84	1.78	0.00	0.000000	0.00	0.00	100.67	0.000112	184.26	3.58
1995 TO 2004	1995 TO 2004	32.16	0.002076	296.98	2.34	31.81	0.002045	234.23	2.90	0.00	0.000000	0.00	0.00
1996 TO 2005	1996 TO 2005	33.07	0.001906	297.82	2.31	32.61	0.001898	240.72	2.78	0.00	0.000000	0.00	0.00
1997 TO 2006	1997 TO 2006	33.48	0.001811	300.18	2.28	32.98	0.001801	241.08	2.74	0.00	0.000000	0.00	0.00
1998 TO 2007	1998 TO 2007	34.21	0.001730	302.58	2.25	33.64	0.001726	245.22	2.67	0.00	0.000000	0.00	0.00

ORANGE AND ROCKLAND UTILITIES INC. MORTALITY STUDY BY LEAST SQUARE FITTING OF WEIGHTED RETIREMENT RATIOS
ACCOUNT 2382000 METER INSTALLATIONS PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2007

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
2007 TO 2007	2007 TO 2007	73.24	0.000746	324.26	1.98	52.37	0.000629	205.27	3.53	48.07	0.000508	161.22	4.66
2006 TO 2007	2006 TO 2007	61.62	0.000949	333.50	1.85	46.29	0.000736	206.33	3.17	43.76	0.000516	163.40	3.79
2005 TO 2007	2005 TO 2007	70.41	0.000725	340.16	1.77	49.69	0.000576	208.29	3.09	46.03	0.000432	164.02	3.88
2004 TO 2007	2004 TO 2007	25.41	0.003870	289.28	2.47	25.67	0.003909	262.97	2.58	0.00	0.000000	0.00	0.00
2003 TO 2007	2003 TO 2007	27.71	0.002963	294.13	2.40	27.89	0.002993	263.57	2.55	0.00	0.000000	0.00	0.00
2002 TO 2007	2002 TO 2007	29.44	0.002476	297.22	2.34	29.51	0.002498	262.64	2.54	0.00	0.000000	0.00	0.00
2001 TO 2007	2001 TO 2007	30.96	0.002197	298.79	2.31	30.90	0.002213	257.29	2.57	0.00	0.000000	0.00	0.00
2000 TO 2007	2000 TO 2007	32.24	0.001860	301.81	2.27	32.03	0.002018	254.45	2.60	0.00	0.000000	0.00	0.00
1999 TO 2007	1999 TO 2007	33.30	0.001730	302.58	2.25	32.92	0.001862	250.63	2.64	0.00	0.000000	0.00	0.00
1998 TO 2007	1998 TO 2007	34.21	0.001622	304.50	2.24	33.64	0.001726	245.22	2.67	0.00	0.000000	0.00	0.00
1997 TO 2007	1997 TO 2007	34.98	0.001533	304.71	2.23	34.23	0.001612	243.92	2.71	0.00	0.000000	0.00	0.00
1996 TO 2007	1996 TO 2007	35.61	0.001463	305.98	2.22	34.69	0.001516	240.73	2.75	0.00	0.000000	0.00	0.00
1995 TO 2007	1995 TO 2007	36.11	0.001410	305.12	2.21	35.03	0.001439	238.38	2.78	0.00	0.000000	0.00	0.00
1994 TO 2007	1994 TO 2007	36.54	0.001363	305.08	2.21	35.31	0.001379	236.50	2.82	0.00	0.000000	0.00	0.00
1993 TO 2007	1993 TO 2007	36.88	0.001319	305.41	2.20	35.51	0.001327	235.16	2.85	0.00	0.000000	0.00	0.00
1992 TO 2007	1992 TO 2007	37.16	0.001281	306.04	2.20	35.67	0.001278	231.26	2.87	0.00	0.000000	0.00	0.00
1991 TO 2007	1991 TO 2007	37.41	0.001256	307.90	2.20	35.81	0.001234	230.38	2.90	0.00	0.000000	0.00	0.00
1990 TO 2007	1990 TO 2007	37.51	0.001233	306.33	2.19	35.84	0.001204	230.17	2.92	0.00	0.000000	0.00	0.00
1989 TO 2007	1989 TO 2007	37.70	0.001216	307.99	2.19	35.93	0.001176	229.61	2.94	0.00	0.000000	0.00	0.00
1988 TO 2007	1988 TO 2007	37.83	0.001204	307.16	2.18	35.98	0.001155	229.31	2.95	0.00	0.000000	0.00	0.00
1987 TO 2007	1987 TO 2007	37.93	0.001205	307.35	2.18	36.01	0.001140	229.10	2.96	0.00	0.000000	0.00	0.00
1986 TO 2007	1986 TO 2007	37.91	0.001201	308.27	2.18	35.96	0.001138	226.61	2.97	0.00	0.000000	0.00	0.00
1985 TO 2007	1985 TO 2007	37.79	0.001202	309.16	2.18	35.86	0.001131	227.27	2.98	0.00	0.000000	0.00	0.00
1984 TO 2007	1984 TO 2007	37.68	0.001203	309.31	2.18	35.76	0.001129	225.29	2.99	0.00	0.000000	0.00	0.00
1983 TO 2007	1983 TO 2007	37.66	0.001211	308.05	2.18	35.73	0.001138	226.11	3.00	0.00	0.000000	0.00	0.00
1982 TO 2007	1982 TO 2007	37.49	0.001206	307.72	2.18	35.60	0.001131	226.04	3.00	0.00	0.000000	0.00	0.00
1981 TO 2007	1981 TO 2007	37.53	0.001209	308.50	2.19	35.61	0.001135	226.51	3.00	0.00	0.000000	0.00	0.00
1980 TO 2007	1980 TO 2007	37.44	0.001217	306.92	2.19	35.54	0.001141	227.17	3.01	0.00	0.000000	0.00	0.00
1979 TO 2007	1979 TO 2007	37.31	0.001220	307.63	2.19	35.44	0.001141	224.81	3.02	0.00	0.000000	0.00	0.00
1978 TO 2007	1978 TO 2007	37.22	0.001216	307.26	2.19	35.36	0.001136	224.67	3.02	0.00	0.000000	0.00	0.00
1977 TO 2007	1977 TO 2007	37.26	0.001208	307.58	2.19	35.38	0.001123	224.93	3.03	0.00	0.000000	0.00	0.00
1976 TO 2007	1976 TO 2007	37.23	0.001206	307.68	2.18	35.34	0.001121	225.17	3.02	0.00	0.000000	0.00	0.00
1975 TO 2007	1975 TO 2007	37.21	0.001206	307.68	2.18	35.31	0.001121	225.17	3.02	0.00	0.000000	0.00	0.00

ORANGE AND ROCKLAND UTILITIES INC. MORTALITY STUDY BY LEAST SQUARE FITTING OF WEIGHTED RETIREMENT RATIOS
ACCOUNT 2385000 IND. MEAS. AND REG. EQUIP. PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2007

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	204.59	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	59.50	0.001761	168.89	2.95
1977 TO 1986		0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00	57.44	0.001666	168.00	3.01
1978 TO 1987		0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00	57.22	0.001606	168.65	3.04
1979 TO 1988		0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00	57.73	0.001561	168.89	3.06
1980 TO 1989		0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00	55.64	0.001512	168.03	3.19
1981 TO 1990		0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00	56.23	0.001461	166.27	3.29
1982 TO 1991		0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00	56.96	0.001080	165.91	3.40
1983 TO 1992		68.65	0.002334	385.27	1.22	41.96	0.002296	213.27	2.83	39.24	0.002308	182.21	3.17
1984 TO 1993		68.80	0.001880	339.39	1.77	45.68	0.001846	206.87	3.40	43.73	0.001864	184.09	3.81
1985 TO 1994		51.92	0.004244	324.51	1.97	37.52	0.004086	190.59	3.80	36.30	0.004019	155.66	4.92
1986 TO 1995		55.72	0.003937	329.31	1.90	38.86	0.003810	191.73	3.77	37.28	0.003754	156.90	4.95
1987 TO 1996		58.58	0.003644	332.04	1.88	40.48	0.003551	193.93	3.75	38.46	0.003512	157.32	5.10
1988 TO 1997		61.84	0.002616	333.90	1.84	42.48	0.002523	196.57	3.75	39.79	0.002475	159.60	5.10
1989 TO 1998		65.09	0.002407	335.70	1.82	44.48	0.002345	198.95	3.70	41.30	0.002317	161.03	5.10
1990 TO 1999		68.91	0.002269	337.44	1.81	46.57	0.002227	200.77	3.64	43.01	0.002215	161.69	4.82
1991 TO 2000		72.46	0.001947	337.42	1.80	48.88	0.001916	203.57	3.56	44.90	0.001911	163.69	4.63
1992 TO 2001		76.45	0.001476	339.42	1.78	51.53	0.001449	206.67	3.48	47.03	0.001446	169.05	4.63
1993 TO 2002		108.89	0.001180	343.02	1.73	60.63	0.001170	208.64	3.49	50.95	0.001159	161.94	5.10
1994 TO 2003		34.65	0.004087	304.47	2.23	33.82	0.003355	181.87	3.92	35.57	0.003003	150.39	5.10
1995 TO 2004		36.64	0.003394	307.05	2.20	34.74	0.002766	185.67	3.93	36.27	0.002519	153.01	5.10
1996 TO 2005		30.91	0.004184	296.01	2.34	31.67	0.003090	181.54	3.83	34.09	0.002606	151.05	5.10
1997 TO 2006		31.48	0.003974	297.04	2.34	31.66	0.002912	181.61	3.82	34.09	0.002419	151.06	5.10
1998 TO 2007		32.12	0.003900	297.33	2.34	31.64	0.002894	181.73	3.77	34.11	0.002426	151.00	5.10

ORANGE AND ROCKLAND UTILITIES INC. MORTALITY STUDY BY LEAST SQUARE FITTING OF WEIGHTED RETIREMENT RATIOS
ACCOUNT 2385000 IND. MEAS. AND REG. EQUIP. PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2007

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
2007 TO 2007	2007	399.00	0.000000	99.87	5.10	399.00	0.000000	99.87	5.10	399.00	0.000000	99.87	5.10
2006 TO 2007	2007	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 2007	2007	29.76	0.005796	287.27	2.49	27.62	0.004415	179.24	3.23	31.11	0.003344	146.24	5.10
2004 TO 2007	2007	33.01	0.004367	295.34	2.37	29.89	0.003392	182.33	3.51	32.67	0.002781	146.45	5.10
2003 TO 2007	2007	25.36	0.006739	278.00	2.63	26.49	0.004462	179.31	3.21	30.39	0.003341	146.43	5.10
2002 TO 2007	2007	27.23	0.005318	284.60	2.51	28.30	0.003548	178.47	3.52	31.56	0.002791	150.50	5.10
2001 TO 2007	2007	28.80	0.004667	289.93	2.43	29.56	0.003244	181.01	3.70	32.46	0.002647	152.48	5.10
2000 TO 2007	2007	30.10	0.004375	294.06	2.40	30.44	0.003179	182.35	3.74	33.17	0.002678	152.25	5.10
1999 TO 2007	2007	31.18	0.004088	293.44	2.37	31.11	0.002998	181.64	3.75	33.70	0.002518	152.80	5.10
1998 TO 2007	2007	32.12	0.003900	297.33	2.34	31.64	0.002894	181.73	3.77	34.11	0.002426	151.00	5.10
1997 TO 2007	2007	32.95	0.003716	298.98	2.32	32.08	0.002758	182.37	3.81	34.39	0.002281	149.74	5.10
1996 TO 2007	2007	33.64	0.003643	298.77	2.30	32.39	0.002733	183.67	3.81	34.61	0.002265	151.71	5.10
1995 TO 2007	2007	34.23	0.003585	299.46	2.28	32.63	0.002710	182.35	3.80	34.74	0.002244	151.12	5.10
1994 TO 2007	2007	34.12	0.003760	300.37	2.29	32.53	0.002895	182.92	3.79	34.66	0.002413	151.48	5.10
1993 TO 2007	2007	34.61	0.003711	301.94	2.28	32.73	0.002824	184.84	3.80	34.77	0.002408	150.97	5.10
1992 TO 2007	2007	34.46	0.003669	303.24	2.27	32.65	0.002790	184.48	3.81	34.72	0.002394	151.53	5.10
1991 TO 2007	2007	34.85	0.003622	302.71	2.26	32.90	0.002775	183.89	3.81	34.77	0.002365	151.22	5.10
1990 TO 2007	2007	35.18	0.003596	302.69	2.26	32.98	0.002759	183.44	3.83	34.80	0.002344	150.87	5.10
1989 TO 2007	2007	35.46	0.003569	303.19	2.25	33.03	0.002744	183.15	3.82	34.83	0.002331	150.75	5.10
1988 TO 2007	2007	35.70	0.003549	303.93	2.25	33.07	0.002732	182.93	3.82	34.85	0.002321	150.67	5.10
1987 TO 2007	2007	35.91	0.003533	302.16	2.25	33.10	0.002722	182.77	3.82	34.86	0.002314	150.61	5.10
1986 TO 2007	2007	36.09	0.003519	303.43	2.25	33.11	0.002715	182.71	3.81	34.85	0.002307	150.67	5.10
1985 TO 2007	2007	36.19	0.003503	302.60	2.25	33.13	0.002692	182.61	3.81	34.85	0.002289	150.65	5.10
1984 TO 2007	2007	36.32	0.003483	304.24	2.24	33.07	0.002683	185.98	3.76	34.75	0.002284	151.07	5.10
1983 TO 2007	2007	36.35	0.003472	304.01	2.22	33.08	0.002675	185.90	3.76	34.75	0.002275	151.07	5.10
1982 TO 2007	2007	36.45	0.003458	305.92	2.22	33.09	0.002667	185.85	3.76	34.75	0.002267	151.07	5.10
1981 TO 2007	2007	36.53	0.003447	305.25	2.22	33.09	0.002660	185.86	3.76	34.75	0.002259	151.07	5.10
1980 TO 2007	2007	36.59	0.003436	304.74	2.22	33.09	0.002652	185.87	3.75	34.75	0.002252	151.08	5.10
1979 TO 2007	2007	36.62	0.003426	304.46	2.22	33.09	0.002645	185.88	3.75	34.75	0.002244	151.08	5.10
1978 TO 2007	2007	36.66	0.003415	304.15	2.22	33.09	0.002639	185.89	3.75	34.75	0.002238	151.07	5.10
1977 TO 2007	2007	36.69	0.003406	306.63	2.22	33.08	0.002632	185.89	3.75	34.76	0.002232	151.06	5.10
1976 TO 2007	2007	36.71	0.003398	306.43	2.22	33.08	0.002632	185.89	3.75	34.76	0.002226	151.06	5.10
1975 TO 2007	2007	36.73	0.003389	306.27	2.22	33.08	0.002632	185.89	3.75	34.76	0.002226	151.06	5.10

ORANGE AND ROCKLAND UTILITIES INC. MORTALITY STUDY BY LEAST SQUARE FITTING OF WEIGHTED RETIREMENT RATIOS
ACCOUNT 2386000 OTHER PROP. ON CUST. PREM. PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2007
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	EQUIV. H CURVE
1975 TO 1984		7.48	0.041571	207.24	3.84	0.00	0.000000	0.00	0.00	0.00
1976 TO 1985		3.03	0.045671	677.01	0.04	0.00	0.000000	0.00	0.00	0.00
1977 TO 1986		0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00	1.29
1978 TO 1987		399.00	0.000000	99.87	5.10	399.00	0.000000	99.87	5.10	5.10
1979 TO 1988		399.00	0.000000	99.87	5.10	399.00	0.000000	99.87	5.10	5.10
1980 TO 1989		399.00	0.000000	99.87	5.10	399.00	0.000000	99.87	5.10	5.10
1981 TO 1990		399.00	0.000000	99.87	5.10	399.00	0.000000	99.87	5.10	5.10
1982 TO 1991		399.00	0.000000	99.87	5.10	399.00	0.000000	99.87	5.10	5.10
1983 TO 1992		399.00	0.000000	99.87	5.10	399.00	0.000000	99.87	5.10	5.10
1984 TO 1993		399.00	0.000000	99.87	5.10	399.00	0.000000	99.87	5.10	5.10
1985 TO 1994		399.00	0.000000	99.87	5.10	399.00	0.000000	99.87	5.10	5.10
1986 TO 1995		399.00	0.000000	99.87	5.10	399.00	0.000000	99.87	5.10	5.10
1987 TO 1996		399.00	0.000000	99.87	5.10	399.00	0.000000	99.87	5.10	5.10
1988 TO 1997		399.00	0.000000	99.87	5.10	399.00	0.000000	99.87	5.10	5.10
1989 TO 1998		399.00	0.000000	99.87	5.10	399.00	0.000000	99.87	5.10	5.10
1990 TO 1999		399.00	0.000000	99.87	5.10	399.00	0.000000	99.87	5.10	5.10
1991 TO 2000		399.00	0.000000	99.87	5.10	399.00	0.000000	99.87	5.10	5.10
1992 TO 2001		399.00	0.000000	99.87	5.10	399.00	0.000000	99.87	5.10	5.10
1993 TO 2002		399.00	0.000000	99.87	5.10	399.00	0.000000	99.87	5.10	5.10
1994 TO 2003		26.71	0.004861	316.31	2.06	0.00	0.000000	0.00	0.00	0.00
1995 TO 2004		29.55	0.003899	319.75	2.00	0.00	0.000000	0.00	0.00	0.00
1996 TO 2005		25.28	0.004418	310.52	2.11	0.00	0.000000	0.00	0.00	0.00
1997 TO 2006		23.90	0.004336	307.55	2.15	0.00	0.000000	0.00	0.00	0.00
1998 TO 2007		25.90	0.003783	318.48	2.03	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 2386000 OTHER PROP. ON CUST. PREM. PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2007

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
2007 TO 2007		399.00	0.000000	99.87	5.10	399.00	0.000000	99.87	5.10	399.00	0.000000	99.87	5.10
2006 TO 2007		28.76	0.003610	356.36	1.52	0.00	0.000000	0.00	0.00	187.28	0.003373	212.78	-2.60
2005 TO 2007		23.57	0.005056	345.78	1.64	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
2004 TO 2007		26.47	0.004417	338.16	1.78	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
2003 TO 2007		21.91	0.004859	344.62	1.64	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
2002 TO 2007		23.44	0.004312	334.94	1.79	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
2001 TO 2007		24.45	0.004191	329.20	1.89	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
2000 TO 2007		25.12	0.004043	320.50	1.97	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1999 TO 2007		25.58	0.003909	318.65	2.01	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1998 TO 2007		25.90	0.003783	318.48	2.03	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1997 TO 2007		26.15	0.003671	319.37	2.04	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1996 TO 2007		26.36	0.003564	316.76	2.03	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1995 TO 2007		26.53	0.003482	318.46	2.01	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1994 TO 2007		26.65	0.003432	320.83	2.01	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1993 TO 2007		26.77	0.003383	319.42	2.00	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1992 TO 2007		26.89	0.003337	321.65	1.98	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1991 TO 2007		27.01	0.003311	323.96	1.96	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1990 TO 2007		27.08	0.003318	323.06	1.96	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1989 TO 2007		27.15	0.003324	322.26	1.96	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1988 TO 2007		27.21	0.003329	325.22	1.95	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1987 TO 2007		27.27	0.003334	324.59	1.95	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1986 TO 2007		27.31	0.003337	324.04	1.95	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1985 TO 2007		27.35	0.003340	323.57	1.95	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1984 TO 2007		27.39	0.003336	323.16	1.95	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1983 TO 2007		27.42	0.003306	322.81	1.94	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1982 TO 2007		27.44	0.003306	322.53	1.94	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1981 TO 2007		27.46	0.003290	325.94	1.94	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1980 TO 2007		27.48	0.003283	325.75	1.94	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1979 TO 2007		27.49	0.003283	325.60	1.94	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1978 TO 2007		27.50	0.003282	325.49	1.94	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1977 TO 2007		11.47	0.014120	492.61	0.25	0.00	0.000000	0.00	0.00	15.47	0.018808	300.55	-1.62
1976 TO 2007		11.99	0.012211	471.20	0.37	0.00	0.000000	0.00	0.00	16.61	0.009191	286.03	-1.18
1975 TO 2007		12.35	0.011396	457.52	0.49	0.00	0.000000	0.00	0.00	17.33	0.008695	279.92	-0.94

ORANGE AND ROCKLAND UTILITIES INC. MORTALITY STUDY BY LEAST SQUARE FITTING OF WEIGHTED RETIREMENT RATIOS
ACCOUNT 3390000 STRUCTURES AND IMPROVEMENTS PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2007

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	60.29	0.001707	339.18	1.78	52.33	0.001695	232.18	2.67	51.63	0.001712	217.88	2.77
1953 TO 1962	1953 TO 1962	62.88	0.001463	344.32	1.71	55.08	0.001462	244.21	2.44	0.00	0.000000	0.00	0.00
1954 TO 1963	1954 TO 1963	67.34	0.002302	443.28	0.66	0.00	0.000000	0.00	0.00	48.45	0.002313	195.05	2.16
1955 TO 1964	1955 TO 1964	68.73	0.002232	448.87	0.61	0.00	0.000000	0.00	0.00	49.63	0.002251	198.46	2.11
1956 TO 1965	1956 TO 1965	60.07	0.002229	428.64	0.79	57.64	0.002249	363.48	1.04	47.10	0.002235	202.77	2.07
1957 TO 1966	1957 TO 1966	64.71	0.002174	444.32	0.66	63.76	0.002193	414.81	0.75	49.25	0.002191	204.07	2.01
1958 TO 1967	1958 TO 1967	47.13	0.002988	406.29	1.00	45.31	0.003012	329.93	1.28	42.35	0.003022	227.87	1.74
1959 TO 1968	1959 TO 1968	42.80	0.003921	512.87	0.07	0.00	0.000000	0.00	0.00	37.21	0.003924	243.19	1.07
1960 TO 1969	1960 TO 1969	19.40	0.016450	543.88	-0.18	0.00	0.000000	0.00	0.00	18.41	0.016433	426.31	0.12
1961 TO 1970	1961 TO 1970	19.86	0.015898	501.11	0.17	0.00	0.000000	0.00	0.00	17.87	0.015821	411.30	0.17
1962 TO 1971	1962 TO 1971	20.60	0.012885	473.23	0.40	0.00	0.000000	0.00	0.00	17.85	0.012635	417.31	0.27
1963 TO 1972	1963 TO 1972	21.24	0.012074	454.35	0.56	0.00	0.000000	0.00	0.00	17.96	0.011763	425.97	0.37
1964 TO 1973	1964 TO 1973	22.33	0.011454	423.25	0.81	0.00	0.000000	0.00	0.00	18.90	0.011216	420.57	0.59
1965 TO 1974	1965 TO 1974	22.96	0.010534	415.95	0.90	0.00	0.000000	0.00	0.00	19.43	0.010277	429.82	0.67
1966 TO 1975	1966 TO 1975	23.60	0.010568	404.58	0.99	0.00	0.000000	0.00	0.00	20.14	0.010344	484.10	0.63
1967 TO 1976	1967 TO 1976	23.99	0.010096	402.17	1.04	0.00	0.000000	0.00	0.00	21.39	0.009872	586.65	-0.41
1968 TO 1977	1968 TO 1977	25.80	0.009592	405.11	1.02	0.00	0.000000	0.00	0.00	25.32	0.009397	630.05	-2.60
1969 TO 1978	1969 TO 1978	26.91	0.008706	395.80	1.08	0.00	0.000000	0.00	0.00	39.46	0.008511	1009.78	-2.60
1970 TO 1979	1970 TO 1979	61.39	0.002064	412.94	0.95	0.00	0.000000	0.00	0.00	52.01	0.002037	200.92	1.88
1971 TO 1980	1971 TO 1980	80.13	0.001459	432.43	0.77	0.00	0.000000	0.00	0.00	64.89	0.001386	193.39	1.77
1972 TO 1981	1972 TO 1981	90.26	0.001021	441.51	0.66	0.00	0.000000	0.00	0.00	67.68	0.000938	186.90	2.02
1973 TO 1982	1973 TO 1982	96.95	0.000953	411.05	0.67	0.00	0.000000	0.00	0.00	71.67	0.000900	184.88	2.13
1974 TO 1983	1974 TO 1983	123.61	0.000922	322.40	0.07	0.00	0.000000	0.00	0.00	77.24	0.000881	180.60	2.17
1975 TO 1984	1975 TO 1984	53.29	0.001603	379.99	1.27	0.00	0.000000	0.00	0.00	51.55	0.001614	241.50	1.68
1976 TO 1985	1976 TO 1985	56.61	0.001199	375.38	1.33	0.00	0.000000	0.00	0.00	53.76	0.001202	218.57	1.94
1977 TO 1986	1977 TO 1986	43.40	0.001632	360.60	1.50	43.28	0.001642	340.83	1.56	43.62	0.001641	244.15	1.78
1978 TO 1987	1978 TO 1987	44.04	0.001503	359.87	1.51	43.88	0.001512	338.42	1.58	44.08	0.001515	250.66	1.77
1979 TO 1988	1979 TO 1988	43.95	0.001444	351.54	1.59	43.91	0.001453	347.33	1.61	0.00	0.000000	0.00	0.00
1980 TO 1989	1980 TO 1989	45.42	0.001379	348.95	1.63	45.18	0.001387	324.28	1.72	0.00	0.000000	0.00	0.00
1981 TO 1990	1981 TO 1990	46.57	0.001294	346.76	1.66	46.23	0.001301	319.05	1.77	0.00	0.000000	0.00	0.00
1982 TO 1991	1982 TO 1991	47.76	0.001172	350.70	1.62	47.19	0.001178	314.66	1.77	0.00	0.000000	0.00	0.00
1983 TO 1992	1983 TO 1992	47.21	0.001197	348.44	1.65	46.81	0.001204	321.54	1.75	0.00	0.000000	0.00	0.00
1984 TO 1993	1984 TO 1993	48.38	0.001222	348.27	1.65	48.15	0.001230	333.34	1.70	0.00	0.000000	0.00	0.00
1985 TO 1994	1985 TO 1994	58.38	0.001084	360.59	1.50	0.00	0.000000	0.00	0.00	59.84	0.001095	299.96	1.47
1986 TO 1995	1986 TO 1995	61.46	0.001096	363.65	1.46	0.00	0.000000	0.00	0.00	64.44	0.001108	363.91	1.23
1987 TO 1996	1987 TO 1996	84.01	0.000663	381.50	1.26	0.00	0.000000	0.00	0.00	100.68	0.000649	197.17	1.77
1988 TO 1997	1988 TO 1997	84.99	0.000616	384.15	1.24	0.00	0.000000	0.00	0.00	88.69	0.000603	200.14	1.95
1989 TO 1998	1989 TO 1998	97.27	0.000492	387.08	1.21	0.00	0.000000	0.00	0.00	98.48	0.000490	208.68	1.93
1990 TO 1999	1990 TO 1999	103.77	0.000428	384.04	1.19	0.00	0.000000	0.00	0.00	130.22	0.000427	213.86	1.54
1991 TO 2000	1991 TO 2000	101.70	0.000600	391.82	1.15	0.00	0.000000	0.00	0.00	112.01	0.000600	203.11	1.85
1992 TO 2001	1992 TO 2001	104.86	0.000572	390.02	1.09	0.00	0.000000	0.00	0.00	97.66	0.000567	189.95	2.27
1993 TO 2002	1993 TO 2002	75.15	0.000929	393.20	1.14	0.00	0.000000	0.00	0.00	67.81	0.000926	199.81	2.20
1994 TO 2003	1994 TO 2003	64.27	0.000903	383.56	1.25	63.41	0.000908	360.33	1.32	0.00	0.000000	0.00	0.00
1995 TO 2004	1995 TO 2004	52.40	0.001274	378.84	1.28	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1996 TO 2005	1996 TO 2005	45.93	0.001444	369.01	1.39	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1997 TO 2006	1997 TO 2006	45.29	0.001515	372.02	1.37	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1998 TO 2007	1998 TO 2007	44.13	0.001557	393.18	1.13	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
ACCOUNT 3390000 STRUCTURES AND IMPROVEMENTS PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2007
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
2007 TO 2007	2007	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00	55.90	0.003583	333.64	-1.64
2006 TO 2007	2007	47.78	0.002651	467.78	0.45	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
2005 TO 2007	2007	39.15	0.002779	399.79	1.07	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
2004 TO 2007	2007	35.82	0.002783	400.56	1.05	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
2003 TO 2007	2007	36.52	0.002269	398.40	1.07	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
2002 TO 2007	2007	35.91	0.002430	405.16	1.01	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
2001 TO 2007	2007	38.27	0.002151	408.92	0.98	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
2000 TO 2007	2007	40.22	0.001916	404.04	1.02	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1999 TO 2007	2007	42.36	0.001692	400.16	1.07	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1998 TO 2007	2007	44.13	0.001557	393.18	1.13	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1997 TO 2007	2007	45.33	0.001421	391.57	1.16	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1996 TO 2007	2007	46.25	0.001312	388.09	1.20	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1995 TO 2007	2007	47.51	0.001260	382.03	1.25	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1994 TO 2007	2007	48.38	0.001215	379.27	1.28	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1993 TO 2007	2007	49.00	0.001200	378.58	1.32	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1992 TO 2007	2007	49.21	0.001158	374.94	1.31	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1991 TO 2007	2007	49.79	0.001125	376.56	1.34	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1990 TO 2007	2007	50.31	0.001096	374.65	1.35	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1989 TO 2007	2007	50.71	0.001055	373.67	1.36	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1988 TO 2007	2007	50.61	0.001039	372.44	1.37	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1987 TO 2007	2007	50.89	0.001004	372.34	1.39	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1986 TO 2007	2007	49.29	0.000989	370.29	1.41	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1985 TO 2007	2007	49.62	0.000972	367.80	1.45	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1984 TO 2007	2007	48.49	0.000963	364.02	1.44	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1983 TO 2007	2007	48.69	0.000955	364.57	1.44	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1982 TO 2007	2007	48.97	0.000943	364.51	1.44	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1981 TO 2007	2007	49.21	0.000937	364.78	1.44	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1980 TO 2007	2007	49.44	0.000931	365.07	1.44	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1979 TO 2007	2007	49.55	0.000924	366.31	1.42	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1978 TO 2007	2007	49.59	0.000920	370.03	1.39	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1977 TO 2007	2007	49.78	0.000915	368.62	1.39	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1976 TO 2007	2007	49.93	0.000906	369.52	1.39	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1975 TO 2007	2007	49.94	0.000909	369.44	1.39	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1974 TO 2007	2007	50.09	0.000904	368.31	1.39	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1973 TO 2007	2007	50.07	0.000897	368.51	1.40	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1972 TO 2007	2007	50.15	0.000897	367.93	1.40	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1971 TO 2007	2007	50.17	0.000894	369.78	1.40	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1970 TO 2007	2007	49.95	0.000882	369.39	1.40	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1969 TO 2007	2007	46.71	0.001038	373.60	1.34	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1968 TO 2007	2007	46.60	0.001042	376.60	1.31	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1967 TO 2007	2007	46.25	0.001039	375.10	1.32	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1966 TO 2007	2007	46.39	0.001031	376.14	1.31	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1965 TO 2007	2007	46.37	0.001027	376.34	1.31	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1964 TO 2007	2007	46.47	0.001024	375.54	1.31	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1963 TO 2007	2007	46.40	0.001026	378.26	1.30	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1962 TO 2007	2007	46.49	0.001022	377.49	1.30	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1961 TO 2007	2007	46.55	0.001016	377.00	1.29	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1960 TO 2007	2007	46.58	0.001013	378.95	1.29	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1959 TO 2007	2007	46.49	0.001012	377.49	1.30	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1958 TO 2007	2007	46.57	0.001010	376.88	1.30	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1957 TO 2007	2007	46.64	0.001007	376.31	1.30	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1956 TO 2007	2007	46.69	0.001006	378.05	1.30	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1955 TO 2007	2007	46.75	0.001003	377.54	1.30	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
ACCOUNT 3390000 STRUCTURES AND IMPROVEMENTS PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2007

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)
1954 TO 2007		46.81	0.001001	377.07	1.30	0.00	0.000000	0.00	0.00	0.00
1953 TO 2007		46.81	0.001005	377.07	1.30	0.00	0.000000	0.00	0.00	0.00
1952 TO 2007		46.81	0.001003	377.04	1.31	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 33911100 OFFICE FURNITURE AND EQUIP. PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2007

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		42.46	0.001475	370.96	1.36	0.00	0.000000	0.00	0.00	40.87	0.001487	255.71	1.64
1953 TO 1962		34.23	0.001579	387.06	1.19	0.00	0.000000	0.00	0.00	33.85	0.001598	308.68	1.29
1954 TO 1963		31.00	0.001697	417.76	0.88	0.00	0.000000	0.00	0.00	30.69	0.001679	314.45	0.97
1955 TO 1964		30.46	0.001615	425.09	0.81	0.00	0.000000	0.00	0.00	32.31	0.001573	431.72	0.17
1956 TO 1965		28.18	0.001815	441.86	0.68	0.00	0.000000	0.00	0.00	28.99	0.001750	401.85	0.37
1957 TO 1966		27.33	0.001751	440.96	0.66	0.00	0.000000	0.00	0.00	28.52	0.001696	489.07	0.07
1958 TO 1967		29.16	0.001594	471.56	0.41	0.00	0.000000	0.00	0.00	29.47	0.001561	378.30	0.34
1959 TO 1968		29.21	0.001440	484.44	0.31	0.00	0.000000	0.00	0.00	30.09	0.001361	403.75	-0.02
1960 TO 1969		27.09	0.001850	492.84	0.24	0.00	0.000000	0.00	0.00	27.09	0.001858	415.31	0.21
1961 TO 1970		24.35	0.002203	478.43	0.36	0.00	0.000000	0.00	0.00	24.09	0.002102	396.40	0.26
1962 TO 1971		25.65	0.002021	461.92	0.48	0.00	0.000000	0.00	0.00	25.50	0.001899	405.94	0.23
1963 TO 1972		27.83	0.001895	512.10	0.08	0.00	0.000000	0.00	0.00	27.57	0.001842	382.62	0.00
1964 TO 1973		31.84	0.001822	485.26	0.30	0.00	0.000000	0.00	0.00	33.30	0.001807	442.88	-0.43
1965 TO 1974		33.59	0.001735	471.90	0.41	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1966 TO 1975		37.88	0.001698	481.77	0.32	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1967 TO 1976		35.74	0.001751	538.65	-0.13	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1968 TO 1977		30.40	0.002067	475.37	0.38	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1969 TO 1978		26.65	0.003064	519.77	0.02	0.00	0.000000	0.00	0.00	39.24	0.002065	745.40	-2.60
1970 TO 1979		28.50	0.003112	521.06	0.00	0.00	0.000000	0.00	0.00	26.37	0.002984	343.19	0.08
1971 TO 1980		26.04	0.002987	531.78	-0.10	0.00	0.000000	0.00	0.00	28.09	0.003094	332.81	0.16
1972 TO 1981		27.24	0.002714	512.06	0.06	0.00	0.000000	0.00	0.00	25.88	0.002902	334.27	0.00
1973 TO 1982		29.56	0.002624	471.89	0.41	0.00	0.000000	0.00	0.00	27.07	0.002628	326.88	0.11
1974 TO 1983		29.87	0.002497	450.23	0.59	0.00	0.000000	0.00	0.00	29.45	0.002535	310.75	0.39
1975 TO 1984		31.68	0.002439	443.55	0.66	0.00	0.000000	0.00	0.00	29.83	0.002427	320.12	0.47
1976 TO 1985		33.31	0.002157	430.85	0.77	0.00	0.000000	0.00	0.00	31.72	0.002394	310.51	0.58
1977 TO 1986		15.37	0.005075	484.62	0.26	0.00	0.000000	0.00	0.00	33.46	0.002127	309.33	0.68
1978 TO 1987		16.01	0.004554	484.13	0.27	0.00	0.000000	0.00	0.00	15.18	0.005072	497.38	0.32
1979 TO 1988		17.14	0.004007	463.82	0.44	0.00	0.000000	0.00	0.00	15.88	0.004570	488.10	0.28
1980 TO 1989		18.04	0.003709	446.14	0.63	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1981 TO 1990		19.86	0.003724	430.59	0.77	19.90	0.003745	419.70	0.77	0.00	0.000000	0.00	0.00
1982 TO 1991		19.85	0.003429	430.83	0.77	19.96	0.003439	398.36	0.78	0.00	0.000000	0.00	0.00
1983 TO 1992		19.87	0.003244	420.26	0.86	19.96	0.003255	393.30	0.87	0.00	0.000000	0.00	0.00
1984 TO 1993		18.79	0.003279	428.50	0.75	18.88	0.003282	399.81	0.75	0.00	0.000000	0.00	0.00
1985 TO 1994		17.03	0.003298	449.19	0.57	17.07	0.003311	430.66	0.56	0.00	0.000000	0.00	0.00
1986 TO 1995		17.74	0.003082	436.84	0.69	17.80	0.003080	401.61	0.69	0.00	0.000000	0.00	0.00
1987 TO 1996		35.04	0.001527	472.38	0.41	0.00	0.000000	0.00	0.00	42.73	0.001507	328.83	-0.54
1988 TO 1997		38.27	0.001434	463.77	0.47	0.00	0.000000	0.00	0.00	48.04	0.001422	315.37	-0.41
1989 TO 1998		41.91	0.001326	473.67	0.39	0.00	0.000000	0.00	0.00	51.66	0.001321	299.08	-0.12
1990 TO 1999		32.91	0.001476	451.29	0.58	0.00	0.000000	0.00	0.00	70.23	0.001477	567.40	-2.60
1991 TO 2000		24.64	0.003121	342.95	1.70	24.52	0.002992	283.41	1.73	0.00	0.000000	0.00	0.00
1992 TO 2001		24.88	0.003141	339.67	1.72	24.50	0.002996	279.55	1.72	0.00	0.000000	0.00	0.00
1993 TO 2002		22.76	0.003359	353.64	1.57	22.30	0.003252	298.17	1.50	0.00	0.000000	0.00	0.00
1994 TO 2003		19.73	0.004875	332.04	1.79	19.59	0.004892	324.12	1.73	0.00	0.000000	0.00	0.00
1995 TO 2004		20.71	0.006321	301.81	2.21	20.76	0.006342	286.59	2.21	0.00	0.000000	0.00	0.00
1996 TO 2005		20.27	0.006717	298.42	2.30	20.27	0.006726	278.79	2.27	0.00	0.000000	0.00	0.00
1997 TO 2006		20.18	0.007107	289.86	2.39	20.02	0.007072	267.24	2.27	0.00	0.000000	0.00	0.00
1998 TO 2007		19.60	0.007236	288.25	2.41	18.94	0.007136	266.62	2.07	0.00	0.000000	0.00	0.00

FIRST DEGREE				SECOND DEGREE				THIRD DEGREE					
YEAR	YEAR	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
2007	TO 2007	18.09	0.005395	384.25	1.22	0.00	0.000000	0.00	0.00	42.50	0.005207	683.57	-2.60
2006	TO 2007	22.98	0.005915	302.45	2.23	22.86	0.005948	286.57	2.29	0.00	0.000000	0.00	0.00
2005	TO 2007	22.47	0.005485	287.02	2.44	22.28	0.005486	249.09	2.63	0.00	0.000000	0.00	0.00
2004	TO 2007	22.62	0.007659	263.07	2.87	22.88	0.007540	207.60	3.48	0.00	0.000000	0.00	0.00
2003	TO 2007	18.27	0.009537	283.40	2.46	17.54	0.009485	259.39	2.14	0.00	0.000000	0.00	0.00
2002	TO 2007	17.28	0.009140	315.34	2.03	16.02	0.009116	296.55	1.54	0.00	0.000000	0.00	0.00
2001	TO 2007	17.99	0.008431	319.55	1.96	16.56	0.008404	292.89	1.48	0.00	0.000000	0.00	0.00
2000	TO 2007	19.03	0.008967	270.65	2.74	16.76	0.008239	253.56	1.57	0.00	0.000000	0.00	0.00
1999	TO 2007	18.97	0.007919	282.06	2.50	17.49	0.007597	265.87	1.76	0.00	0.000000	0.00	0.00
1998	TO 2007	19.60	0.007236	288.25	2.41	18.94	0.007136	266.62	2.07	0.00	0.000000	0.00	0.00
1997	TO 2007	20.18	0.006769	294.92	2.34	19.96	0.006743	268.00	2.23	0.00	0.000000	0.00	0.00
1996	TO 2007	20.65	0.006434	297.78	2.29	20.59	0.006436	274.34	2.26	0.00	0.000000	0.00	0.00
1995	TO 2007	21.05	0.005951	301.67	2.24	21.05	0.005965	277.88	2.25	0.00	0.000000	0.00	0.00
1994	TO 2007	20.45	0.005466	320.22	2.00	20.30	0.005475	297.98	1.95	0.00	0.000000	0.00	0.00
1993	TO 2007	20.20	0.005233	329.25	1.86	19.95	0.005238	308.26	1.79	0.00	0.000000	0.00	0.00
1992	TO 2007	20.38	0.005015	331.20	1.85	20.21	0.005029	314.14	1.80	0.00	0.000000	0.00	0.00
1991	TO 2007	20.49	0.004855	334.28	1.80	20.32	0.004868	317.48	1.75	0.00	0.000000	0.00	0.00
1990	TO 2007	20.74	0.004720	335.11	1.79	20.61	0.004736	317.85	1.76	0.00	0.000000	0.00	0.00
1989	TO 2007	20.97	0.004595	336.15	1.79	20.87	0.004613	318.65	1.77	0.00	0.000000	0.00	0.00
1988	TO 2007	21.15	0.004517	333.26	1.79	21.07	0.004536	320.40	1.78	0.00	0.000000	0.00	0.00
1987	TO 2007	21.26	0.004442	336.34	1.77	21.18	0.004461	323.47	1.76	0.00	0.000000	0.00	0.00
1986	TO 2007	19.35	0.004452	352.95	1.54	18.88	0.004423	325.77	1.44	0.00	0.000000	0.00	0.00
1985	TO 2007	19.35	0.004340	353.96	1.52	19.17	0.004331	331.31	1.44	0.00	0.000000	0.00	0.00
1984	TO 2007	19.57	0.004243	355.12	1.50	19.43	0.004246	337.12	1.45	0.00	0.000000	0.00	0.00
1983	TO 2007	19.74	0.004146	357.08	1.49	19.64	0.004156	338.64	1.45	0.00	0.000000	0.00	0.00
1982	TO 2007	19.92	0.004067	358.94	1.48	19.84	0.004082	345.21	1.45	0.00	0.000000	0.00	0.00
1981	TO 2007	20.07	0.003993	361.15	1.46	20.02	0.004011	347.12	1.45	0.00	0.000000	0.00	0.00
1980	TO 2007	19.97	0.003920	363.04	1.43	19.93	0.003939	353.74	1.42	0.00	0.000000	0.00	0.00
1979	TO 2007	20.03	0.003876	367.01	1.41	19.99	0.003895	357.62	1.40	0.00	0.000000	0.00	0.00
1978	TO 2007	19.95	0.003856	368.48	1.36	19.93	0.003876	363.82	1.36	0.00	0.000000	0.00	0.00
1977	TO 2007	19.96	0.003782	368.23	1.37	19.94	0.003802	363.50	1.36	0.00	0.000000	0.00	0.00
1976	TO 2007	19.96	0.003753	373.25	1.34	19.95	0.003773	368.39	1.33	0.00	0.000000	0.00	0.00
1975	TO 2007	20.05	0.003729	371.56	1.32	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1974	TO 2007	20.14	0.003701	374.83	1.31	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1973	TO 2007	20.24	0.003679	373.06	1.30	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1972	TO 2007	20.26	0.003652	377.59	1.28	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1971	TO 2007	20.34	0.003636	376.07	1.27	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1970	TO 2007	20.33	0.003615	376.35	1.27	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1969	TO 2007	20.32	0.003601	376.47	1.26	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1968	TO 2007	20.36	0.003577	380.56	1.25	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1967	TO 2007	20.40	0.003562	379.83	1.24	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1966	TO 2007	20.43	0.003541	379.28	1.24	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1965	TO 2007	20.44	0.003529	383.98	1.23	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1964	TO 2007	20.48	0.003518	383.34	1.22	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1963	TO 2007	20.47	0.003498	383.45	1.21	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1962	TO 2007	20.46	0.003480	383.75	1.21	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1961	TO 2007	20.50	0.003462	383.00	1.21	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1960	TO 2007	20.54	0.003447	382.24	1.20	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1959	TO 2007	20.56	0.003430	386.66	1.20	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1958	TO 2007	20.60	0.003418	385.99	1.20	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1957	TO 2007	20.60	0.003402	385.87	1.20	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1956	TO 2007	20.64	0.003382	385.24	1.20	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1955	TO 2007	20.67	0.003364	384.60	1.19	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
ACCOUNT 3391100 OFFICE FURNITURE AND EQUIP. PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2007

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)
1954 TO 2007		20.70	0.003353	384.03	1.19	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1953 TO 2007		20.72	0.003342	383.60	1.19	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1952 TO 2007		20.75	0.003327	387.96	1.19	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
ACCOUNT 3391200 OFFICE MACHINES PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2007
SUMMARY OF ROLLING BANDS

YEAR	YEAR	AVERAGE SERVICE LIFE (YEARS)	FIRST DEGREE			SECOND DEGREE			THIRD DEGREE				
			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		17.67	0.008222	432.96	0.71	0.00	0.000000	0.00	0.00	17.75	0.008135	346.45	0.71
1953 TO 1962		20.79	0.005692	391.92	1.11	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1954 TO 1963		21.36	0.005974	442.41	0.65	0.00	0.000000	0.00	0.00	31.85	0.005840	384.60	-2.60
1955 TO 1964		20.91	0.005985	423.19	0.84	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1956 TO 1965		23.00	0.005803	441.35	0.66	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1957 TO 1966		24.45	0.005133	480.56	0.31	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1958 TO 1967		34.42	0.002738	387.86	1.19	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1959 TO 1968		38.33	0.002620	395.30	1.12	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1960 TO 1969		36.02	0.002642	365.08	1.42	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1961 TO 1970		28.98	0.003765	367.46	1.41	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1962 TO 1971		30.08	0.003498	367.38	1.42	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1963 TO 1972		25.35	0.004008	400.35	1.05	0.00	0.000000	0.00	0.00	29.69	0.003690	355.37	-1.00
1964 TO 1973		27.86	0.003462	385.86	1.20	0.00	0.000000	0.00	0.00	35.76	0.003170	325.76	-1.42
1965 TO 1974		31.56	0.003121	394.54	1.10	0.00	0.000000	0.00	0.00	34.89	0.002881	276.61	0.41
1966 TO 1975		30.39	0.002802	383.35	1.22	0.00	0.000000	0.00	0.00	33.47	0.002539	300.28	0.32
1967 TO 1976		31.18	0.002939	441.02	0.66	0.00	0.000000	0.00	0.00	32.26	0.002756	271.26	0.51
1968 TO 1977		24.42	0.005093	423.79	0.83	0.00	0.000000	0.00	0.00	25.97	0.004766	340.82	-0.30
1969 TO 1978		22.31	0.005141	419.01	0.87	0.00	0.000000	0.00	0.00	24.25	0.004673	397.93	-1.19
1970 TO 1979		23.77	0.004629	427.09	0.80	0.00	0.000000	0.00	0.00	27.60	0.004174	367.80	-1.98
1971 TO 1980		23.85	0.003679	425.64	0.81	0.00	0.000000	0.00	0.00	29.65	0.003244	403.03	-2.60
1972 TO 1981		24.22	0.003418	431.48	0.77	0.00	0.000000	0.00	0.00	31.78	0.002973	404.32	-2.60
1973 TO 1982		26.37	0.003006	453.16	0.58	0.00	0.000000	0.00	0.00	34.44	0.002735	364.37	-2.60
1974 TO 1983		14.63	0.006187	379.35	1.22	0.00	0.000000	0.00	0.00	14.39	0.005618	469.24	1.57
1975 TO 1984		14.43	0.005978	377.71	1.27	0.00	0.000000	0.00	0.00	14.24	0.005472	460.11	1.60
1976 TO 1985		14.73	0.005577	369.93	1.36	0.00	0.000000	0.00	0.00	14.56	0.005224	442.94	1.64
1977 TO 1986		15.50	0.005032	345.05	1.65	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1978 TO 1987		16.54	0.004361	335.60	1.79	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1979 TO 1988		17.44	0.004463	323.97	1.90	0.00	0.000000	0.00	0.00	15.83	0.005417	337.91	1.91
1980 TO 1989		15.92	0.005355	323.52	1.89	0.00	0.000000	0.00	0.00	16.41	0.005371	326.00	1.86
1981 TO 1990		16.41	0.005295	325.98	1.92	16.42	0.005340	319.73	1.92	16.40	0.005442	307.90	1.76
1982 TO 1991		16.31	0.005450	328.01	1.84	16.33	0.005419	303.20	1.79	16.77	0.005495	277.30	1.78
1983 TO 1992		16.62	0.005870	327.98	1.87	16.61	0.005608	280.01	1.82	16.77	0.005495	277.30	1.78
1984 TO 1993		29.09	0.002702	479.47	0.33	0.00	0.000000	0.00	0.00	37.15	0.002467	211.31	0.70
1985 TO 1994		29.50	0.002924	466.06	0.46	0.00	0.000000	0.00	0.00	36.66	0.002737	214.12	0.78
1986 TO 1995		33.42	0.002615	528.15	-0.05	0.00	0.000000	0.00	0.00	38.24	0.002504	215.73	0.78
1987 TO 1996		34.79	0.002386	521.67	0.00	0.00	0.000000	0.00	0.00	37.40	0.002312	223.24	0.84
1988 TO 1997		32.73	0.002335	496.44	0.20	0.00	0.000000	0.00	0.00	32.56	0.002285	244.13	0.91
1989 TO 1998		32.56	0.002121	489.89	0.26	0.00	0.000000	0.00	0.00	33.70	0.002065	250.76	0.79
1990 TO 1999		37.69	0.001772	542.54	-0.17	0.00	0.000000	0.00	0.00	34.60	0.001758	250.01	0.93
1991 TO 2000		30.15	0.002051	432.79	0.76	27.60	0.002031	306.11	1.27	27.41	0.002035	268.10	1.37
1992 TO 2001		21.90	0.005928	650.72	-1.12	0.00	0.000000	0.00	0.00	22.39	0.005799	292.60	0.09
1993 TO 2002		15.11	0.007257	466.68	0.43	0.00	0.000000	0.00	0.00	16.25	0.007111	427.59	0.56
1994 TO 2003		15.30	0.007780	434.52	0.69	0.00	0.000000	0.00	0.00	16.06	0.007743	389.28	0.96
1995 TO 2004		14.81	0.008211	449.13	0.56	0.00	0.000000	0.00	0.00	15.61	0.008193	374.87	0.92
1996 TO 2005		13.72	0.008260	419.20	0.82	0.00	0.000000	0.00	0.00	14.53	0.008244	381.93	1.27
1997 TO 2006		12.72	0.009048	452.02	0.57	0.00	0.000000	0.00	0.00	13.78	0.009024	395.44	1.18
1998 TO 2007		10.88	0.010231	473.55	0.34	0.00	0.000000	0.00	0.00	12.08	0.010212	434.77	1.15

ORANGE AND ROCKLAND UTILITIES INC. MORTALITY STUDY BY LEAST SQUARE FITTING OF WEIGHTED RETIREMENT RATIOS
ACCOUNT 3391200 OFFICE MACHINES PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2007
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)
2007 TO 2007	2007 TO 2007	4.82	0.030300	715.61	-0.72	0.00	0.000000	0.00	0.00	0.00
2006 TO 2007	2006 TO 2007	7.88	0.019796	526.33	-0.08	0.00	0.000000	0.00	0.00	0.00
2005 TO 2007	2005 TO 2007	10.04	0.014982	383.44	1.13	0.00	0.000000	0.00	0.00	0.00
2004 TO 2007	2004 TO 2007	11.29	0.012484	385.18	1.14	0.00	0.000000	0.00	0.00	0.00
2003 TO 2007	2003 TO 2007	13.15	0.010815	353.55	1.53	0.00	0.000000	0.00	0.00	0.00
2002 TO 2007	2002 TO 2007	10.22	0.012691	405.96	0.97	0.00	0.000000	0.00	0.00	0.00
2001 TO 2007	2001 TO 2007	7.04	0.013825	632.33	-0.85	0.00	0.000000	0.00	0.00	0.00
2000 TO 2007	2000 TO 2007	8.76	0.012578	530.75	-0.11	0.00	0.000000	0.00	0.00	0.00
1999 TO 2007	1999 TO 2007	9.61	0.011622	515.31	0.03	0.00	0.000000	0.00	0.00	0.00
1998 TO 2007	1998 TO 2007	10.88	0.010231	473.55	0.34	0.00	0.000000	0.00	0.00	0.00
1997 TO 2007	1997 TO 2007	11.92	0.009110	448.88	0.58	0.00	0.000000	0.00	0.00	0.00
1996 TO 2007	1996 TO 2007	12.96	0.008323	420.66	0.80	0.00	0.000000	0.00	0.00	0.00
1995 TO 2007	1995 TO 2007	13.62	0.007830	414.98	0.88	0.00	0.000000	0.00	0.00	0.00
1994 TO 2007	1994 TO 2007	14.15	0.007328	406.35	0.93	0.00	0.000000	0.00	0.00	0.00
1993 TO 2007	1993 TO 2007	14.26	0.006865	410.36	0.98	0.00	0.000000	0.00	0.00	0.00
1992 TO 2007	1992 TO 2007	14.56	0.006501	408.73	0.95	0.00	0.000000	0.00	0.00	0.00
1991 TO 2007	1991 TO 2007	14.75	0.006177	410.28	0.95	0.00	0.000000	0.00	0.00	0.00
1990 TO 2007	1990 TO 2007	15.09	0.005843	400.83	1.01	0.00	0.000000	0.00	0.00	0.00
1989 TO 2007	1989 TO 2007	14.91	0.005910	405.84	1.00	0.00	0.000000	0.00	0.00	0.00
1988 TO 2007	1988 TO 2007	15.22	0.005776	397.40	1.05	0.00	0.000000	0.00	0.00	0.00
1987 TO 2007	1987 TO 2007	15.50	0.005622	390.22	1.11	0.00	0.000000	0.00	0.00	0.00
1986 TO 2007	1986 TO 2007	15.75	0.005494	390.53	1.15	0.00	0.000000	0.00	0.00	0.00
1985 TO 2007	1985 TO 2007	15.94	0.005409	385.74	1.19	0.00	0.000000	0.00	0.00	0.00
1984 TO 2007	1984 TO 2007	16.00	0.005275	384.42	1.20	0.00	0.000000	0.00	0.00	0.00
1983 TO 2007	1983 TO 2007	15.22	0.005268	377.76	1.28	0.00	0.000000	0.00	0.00	0.00
1982 TO 2007	1982 TO 2007	15.28	0.005143	376.43	1.25	0.00	0.000000	0.00	0.00	0.00
1981 TO 2007	1981 TO 2007	15.40	0.004985	379.78	1.24	0.00	0.000000	0.00	0.00	0.00
1980 TO 2007	1980 TO 2007	15.47	0.004840	378.18	1.25	0.00	0.000000	0.00	0.00	0.00
1979 TO 2007	1979 TO 2007	15.60	0.004761	381.38	1.25	0.00	0.000000	0.00	0.00	0.00
1978 TO 2007	1978 TO 2007	15.62	0.004722	380.85	1.24	0.00	0.000000	0.00	0.00	0.00
1977 TO 2007	1977 TO 2007	15.60	0.004671	381.38	1.24	0.00	0.000000	0.00	0.00	0.00
1976 TO 2007	1976 TO 2007	15.59	0.004599	381.57	1.20	0.00	0.000000	0.00	0.00	0.00
1975 TO 2007	1975 TO 2007	15.68	0.004547	379.47	1.21	0.00	0.000000	0.00	0.00	0.00
1974 TO 2007	1974 TO 2007	15.77	0.004484	383.70	1.21	0.00	0.000000	0.00	0.00	0.00
1973 TO 2007	1973 TO 2007	15.85	0.004452	381.64	1.21	0.00	0.000000	0.00	0.00	0.00
1972 TO 2007	1972 TO 2007	15.82	0.004432	382.37	1.20	0.00	0.000000	0.00	0.00	0.00
1971 TO 2007	1971 TO 2007	15.89	0.004400	380.69	1.20	0.00	0.000000	0.00	0.00	0.00
1970 TO 2007	1970 TO 2007	15.91	0.004364	380.38	1.21	0.00	0.000000	0.00	0.00	0.00
1969 TO 2007	1969 TO 2007	15.96	0.004344	385.43	1.21	0.00	0.000000	0.00	0.00	0.00
1968 TO 2007	1968 TO 2007	16.01	0.004334	384.25	1.21	0.00	0.000000	0.00	0.00	0.00
1967 TO 2007	1967 TO 2007	16.05	0.004316	383.23	1.20	0.00	0.000000	0.00	0.00	0.00
1966 TO 2007	1966 TO 2007	16.06	0.004301	382.88	1.20	0.00	0.000000	0.00	0.00	0.00
1965 TO 2007	1965 TO 2007	16.10	0.004287	382.06	1.20	0.00	0.000000	0.00	0.00	0.00
1964 TO 2007	1964 TO 2007	16.11	0.004266	381.71	1.20	0.00	0.000000	0.00	0.00	0.00
1963 TO 2007	1963 TO 2007	16.12	0.004241	381.59	1.20	0.00	0.000000	0.00	0.00	0.00
1962 TO 2007	1962 TO 2007	16.14	0.004217	380.94	1.20	0.00	0.000000	0.00	0.00	0.00
1961 TO 2007	1961 TO 2007	16.17	0.004206	386.45	1.20	0.00	0.000000	0.00	0.00	0.00
1960 TO 2007	1960 TO 2007	16.20	0.004192	385.83	1.20	0.00	0.000000	0.00	0.00	0.00
1959 TO 2007	1959 TO 2007	16.22	0.004178	385.34	1.20	0.00	0.000000	0.00	0.00	0.00
1958 TO 2007	1958 TO 2007	16.24	0.004166	384.92	1.20	0.00	0.000000	0.00	0.00	0.00
1957 TO 2007	1957 TO 2007	16.17	0.004145	386.45	1.18	0.00	0.000000	0.00	0.00	0.00
1956 TO 2007	1956 TO 2007	16.18	0.004139	386.35	1.19	0.00	0.000000	0.00	0.00	0.00
1955 TO 2007	1955 TO 2007	16.19	0.004126	386.14	1.19	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 3391200 OFFICE MACHINES PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2007

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
1954 TO 2007	1954 TO 2007	16.20	0.004119	385.91	1.19	0.00	0.000000	0.00	0.00	16.44	0.004017	404.46	1.28
1953 TO 2007	1953 TO 2007	16.20	0.004112	385.75	1.19	0.00	0.000000	0.00	0.00	16.44	0.004012	404.39	1.28
1952 TO 2007	1952 TO 2007	16.17	0.004099	386.57	1.18	0.00	0.000000	0.00	0.00	16.41	0.003997	405.16	1.27

ORANGE AND ROCKLAND UTILITIES INC. MORTALITY STUDY BY LEAST SQUARE FITTING OF WEIGHTED RETIREMENT RATIOS
ACCOUNT 3391700 OFFICE FURNITURE - EDP PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2007

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
1981 TO 1990		14.14	0.015803	328.90	1.87	9.33	0.016273	176.80	3.34	7.87	0.015607	120.64	4.98
1982 TO 1991		23.42	0.005621	394.92	1.08	16.52	0.006055	257.19	2.06	9.47	0.003834	132.05	4.08
1983 TO 1992		31.02	0.004523	436.84	0.71	0.00	0.000000	0.00	0.00	11.42	0.004257	135.68	3.68
1984 TO 1993		39.57	0.003486	486.44	0.29	0.00	0.000000	0.00	0.00	14.04	0.003309	146.04	3.32
1985 TO 1994		18.51	0.003855	348.51	1.59	15.31	0.006087	244.95	2.32	14.70	0.006455	227.95	2.53
1986 TO 1995		20.20	0.007320	353.90	1.52	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1987 TO 1996		15.01	0.006775	356.37	1.46	14.62	0.007072	325.00	1.60	0.00	0.000000	0.00	0.00
1988 TO 1997		16.66	0.006261	381.08	1.21	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1989 TO 1998		12.11	0.021413	317.99	1.99	11.16	0.020032	210.57	2.25	11.20	0.017547	147.31	2.57
1990 TO 1999		11.62	0.017147	339.99	1.62	10.85	0.016023	235.11	1.90	10.83	0.015125	170.81	2.15
1991 TO 2000		11.26	0.016059	377.55	1.24	10.68	0.016066	304.28	1.51	10.59	0.015939	193.65	1.77
1992 TO 2001		10.77	0.015260	376.11	1.22	10.33	0.015166	314.65	1.39	10.35	0.014697	207.73	1.65
1993 TO 2002		10.50	0.013841	414.09	0.91	10.27	0.014169	335.77	1.03	10.19	0.014082	230.61	1.35
1994 TO 2003		9.39	0.016123	367.26	1.32	9.24	0.016268	362.67	1.28	9.39	0.015714	239.60	1.50
1995 TO 2004		9.11	0.014191	378.54	1.23	9.09	0.014550	379.63	1.22	9.14	0.013990	257.14	1.42
1996 TO 2005		8.57	0.012699	402.64	1.44	8.55	0.013004	403.32	1.42	8.62	0.012304	272.59	1.54
1997 TO 2006		8.83	0.011245	390.82	1.67	8.81	0.011499	391.45	1.65	8.86	0.011327	276.60	1.71
1998 TO 2007		8.07	0.010210	414.95	1.77	0.00	0.000000	0.00	0.00	8.09	0.010140	302.89	1.83

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
2007	TO 2007	6.21	0.048125	265.79	2.83	0.000000	0.00	0.00	0.00	0.00	0.000000	0.00	0.00
2006	TO 2007	7.34	0.028456	320.25	2.69	0.000000	0.00	0.00	0.00	0.00	0.000000	0.00	0.00
2005	TO 2007	7.45	0.014810	345.39	2.69	0.000000	0.00	0.00	0.00	0.00	0.000000	0.00	0.00
2004	TO 2007	7.68	0.015749	345.11	2.37	0.000000	0.00	0.00	0.00	0.00	0.000000	0.00	0.00
2003	TO 2007	7.69	0.014591	344.73	2.41	0.000000	0.00	0.00	0.00	0.00	0.000000	0.00	0.00
2002	TO 2007	7.94	0.013981	371.34	2.18	0.000000	0.00	0.00	0.00	0.00	0.013102	367.36	2.23
2001	TO 2007	8.06	0.012780	390.63	2.05	0.000000	0.00	0.00	0.00	0.00	0.012110	322.43	2.07
2000	TO 2007	8.08	0.011327	413.77	1.83	0.000000	0.00	0.00	0.00	0.00	0.010067	307.62	1.87
1999	TO 2007	8.02	0.010380	430.30	1.65	0.000000	0.00	0.00	0.00	0.00	0.009490	305.95	1.74
1998	TO 2007	8.07	0.010210	414.95	1.77	0.000000	0.00	0.00	0.00	0.00	0.010140	302.89	1.78
1997	TO 2007	8.36	0.010894	412.65	1.76	0.000000	0.00	0.00	0.00	0.00	0.010609	281.24	1.73
1996	TO 2007	8.32	0.011238	414.44	1.68	0.000000	0.00	0.00	0.00	0.00	0.010907	273.75	1.74
1995	TO 2007	8.57	0.011370	402.50	1.72	0.000000	0.00	0.00	0.00	0.00	0.010930	283.58	1.77
1994	TO 2007	8.72	0.011435	395.43	1.80	0.011607	403.52	1.68	0.00	0.00	0.011087	269.28	1.79
1993	TO 2007	8.89	0.010877	387.86	1.76	0.011653	378.95	1.73	0.00	0.00	0.010448	260.23	1.82
1992	TO 2007	9.03	0.010492	382.08	1.84	0.010576	362.73	1.75	0.00	0.00	0.009594	258.18	1.83
1991	TO 2007	9.10	0.010069	378.98	1.86	0.010082	360.21	1.76	0.00	0.00	0.009524	256.07	1.85
1990	TO 2007	9.18	0.009954	375.81	1.89	0.009923	346.25	1.78	0.00	0.00	0.009508	255.33	1.86
1989	TO 2007	9.20	0.009895	374.93	1.89	0.009754	343.53	1.82	0.00	0.00	0.009457	253.88	1.89
1988	TO 2007	9.25	0.009808	373.05	1.92	0.009707	342.06	1.86	0.00	0.00	0.009427	252.95	1.91
1987	TO 2007	9.28	0.009754	371.87	1.94	0.009654	341.52	1.87	0.00	0.00	0.009358	252.84	1.92
1986	TO 2007	9.28	0.009684	371.76	1.95	0.009620	341.09	1.87	0.00	0.00	0.009321	252.76	1.91
1985	TO 2007	9.28	0.009645	371.59	1.95	0.009603	341.43	1.87	0.00	0.00	0.009297	252.98	1.91
1984	TO 2007	9.28	0.009629	371.52	1.94	0.009600	341.38	1.87	0.00	0.00	0.009294	252.96	1.91
1983	TO 2007	9.28	0.009625	371.89	1.94	0.009598	341.36	1.87	0.00	0.00	0.009292	252.96	1.91
1982	TO 2007	9.28	0.009623	371.89	1.94	0.009598	341.36	1.87	0.00	0.00	0.009273	253.37	1.91
1981	TO 2007	9.26	0.009607	372.47	1.94	0.009593	341.88	1.87	0.00	0.00	0.009273	253.37	1.91

ORANGE AND ROCKLAND UTILITIES INC. MORTALITY STUDY BY LEAST SQUARE FITTING OF WEIGHTED RETIREMENT RATIOS
ACCOUNT 3392100 TRANS. EQUIP. PASS. CARS PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2007

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		5.63	0.009351	399.96	1.72	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1976 TO 1985		8.01	0.009289	430.90	0.69	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1977 TO 1986		0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00	9.09	0.003434	148.59	1.95
1978 TO 1987		6.17	0.015468	364.51	2.07	5.81	0.012108	197.77	2.11	5.90	0.010900	161.09	2.38
1979 TO 1988		6.65	0.009064	383.66	1.90	6.38	0.008020	227.23	2.03	6.37	0.008083	196.23	2.18
1980 TO 1989		5.98	0.015804	309.61	2.38	5.81	0.009703	197.96	2.19	5.91	0.007984	177.66	2.38
1981 TO 1990		5.89	0.015437	296.98	2.49	5.81	0.010033	198.09	2.34	0.00	0.000000	0.00	0.00
1982 TO 1991		5.97	0.014557	293.23	2.48	5.86	0.010032	196.34	2.34	0.00	0.000000	0.00	0.00
1983 TO 1992		5.88	0.013782	297.86	2.51	5.73	0.008601	200.86	2.27	0.00	0.000000	0.00	0.00
1984 TO 1993		6.13	0.014805	285.33	2.64	6.07	0.008810	189.48	2.57	0.00	0.000000	0.00	0.00
1985 TO 1994		6.27	0.012451	310.85	2.47	6.08	0.006829	189.05	2.32	0.00	0.000000	0.00	0.00
1986 TO 1995		6.15	0.012039	300.75	2.48	6.01	0.007002	191.33	2.30	0.00	0.000000	0.00	0.00
1987 TO 1996		6.32	0.008253	324.24	2.37	6.21	0.005934	217.36	2.29	0.00	0.000000	0.00	0.00
1988 TO 1997		6.70	0.009029	335.67	2.36	6.53	0.006148	206.65	2.23	0.00	0.000000	0.00	0.00
1989 TO 1998		7.02	0.007609	363.44	2.17	6.90	0.007149	253.61	2.16	0.00	0.000000	0.00	0.00
1990 TO 1999		7.99	0.005902	419.49	1.73	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1991 TO 2000		7.84	0.008488	376.46	2.18	7.56	0.007340	244.80	2.03	0.00	0.000000	0.00	0.00
1992 TO 2001		8.33	0.008402	390.19	2.01	8.07	0.008125	291.20	1.95	0.00	0.000000	0.00	0.00
1993 TO 2002		9.01	0.006635	383.04	2.10	8.72	0.006204	280.98	2.06	0.00	0.000000	0.00	0.00
1994 TO 2003		9.22	0.007710	363.20	2.33	9.03	0.007176	260.32	2.31	0.00	0.000000	0.00	0.00
1995 TO 2004		9.27	0.006714	339.92	2.61	9.29	0.005780	231.43	2.73	0.00	0.000000	0.00	0.00
1996 TO 2005		10.07	0.006734	342.58	2.60	10.12	0.006151	242.09	2.85	0.00	0.000000	0.00	0.00
1997 TO 2006		9.33	0.008273	326.85	2.69	9.53	0.007390	225.68	2.89	0.00	0.000000	0.00	0.00
1998 TO 2007		9.33	0.009476	316.29	2.78	9.77	0.007829	209.87	3.17	0.00	0.000000	0.00	0.00

ORANGE AND ROCKLAND UTILITIES INC. MORTALITY STUDY BY LEAST SQUARE FITTING OF WEIGHTED RETIREMENT RATIOS
ACCOUNT 3392100 TRANS. EQUIP. PASS. CARS PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2007

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
2007	TO 2007	6.67	0.018997	277.47	2.78	6.67	0.019302	277.43	2.78	0.00	0.000000	0.00	0.00
2006	TO 2007	6.61	0.013730	294.96	2.63	6.70	0.014002	275.97	2.65	0.00	0.000000	0.00	0.00
2005	TO 2007	7.94	0.016733	333.58	2.53	8.56	0.016514	239.42	2.77	0.00	0.000000	0.00	0.00
2004	TO 2007	8.27	0.016719	320.39	2.67	9.20	0.015399	211.98	3.14	0.00	0.000000	0.00	0.00
2003	TO 2007	8.48	0.014139	324.46	2.70	9.18	0.012871	212.35	3.07	0.00	0.000000	0.00	0.00
2002	TO 2007	8.93	0.012248	319.01	2.78	9.57	0.010936	214.28	3.19	0.00	0.000000	0.00	0.00
2001	TO 2007	9.49	0.011470	310.75	2.86	10.12	0.009782	202.58	3.39	0.00	0.000000	0.00	0.00
2000	TO 2007	8.84	0.009510	311.19	2.82	9.18	0.008788	223.28	3.02	0.00	0.000000	0.00	0.00
1999	TO 2007	9.06	0.009428	325.47	2.77	9.41	0.008287	217.83	3.01	0.00	0.000000	0.00	0.00
1998	TO 2007	9.33	0.009476	316.29	2.78	9.77	0.007829	209.87	3.17	0.00	0.000000	0.00	0.00
1997	TO 2007	9.07	0.008789	325.12	2.72	9.39	0.007702	218.31	2.98	0.00	0.000000	0.00	0.00
1996	TO 2007	9.25	0.008994	318.96	2.74	9.62	0.007588	213.04	3.11	0.00	0.000000	0.00	0.00
1995	TO 2007	8.96	0.008198	329.28	2.65	9.20	0.007087	222.71	2.85	0.00	0.000000	0.00	0.00
1994	TO 2007	8.92	0.008617	341.78	2.56	9.03	0.007073	227.07	2.59	0.00	0.000000	0.00	0.00
1993	TO 2007	8.73	0.008038	349.35	2.44	8.74	0.006518	234.51	2.38	0.00	0.000000	0.00	0.00
1992	TO 2007	8.46	0.007570	360.47	2.33	8.41	0.006375	255.65	2.22	0.00	0.000000	0.00	0.00
1991	TO 2007	8.38	0.007223	364.15	2.29	8.31	0.006028	258.84	2.16	0.00	0.000000	0.00	0.00
1990	TO 2007	8.22	0.006534	358.68	2.26	8.19	0.005686	274.84	2.18	0.00	0.000000	0.00	0.00
1989	TO 2007	7.89	0.005849	373.73	2.21	7.86	0.005389	299.07	2.13	0.00	0.000000	0.00	0.00
1988	TO 2007	7.95	0.005799	371.22	2.22	7.92	0.005286	283.95	2.16	0.00	0.000000	0.00	0.00
1987	TO 2007	7.67	0.005193	371.55	2.16	7.65	0.005063	333.25	2.12	0.00	0.000000	0.00	0.00
1986	TO 2007	7.77	0.005247	366.70	2.19	7.75	0.005009	316.06	2.15	0.00	0.000000	0.00	0.00
1985	TO 2007	7.82	0.005311	364.35	2.21	7.80	0.005018	301.13	2.17	0.00	0.000000	0.00	0.00
1984	TO 2007	7.84	0.005299	363.40	2.22	7.83	0.004988	300.08	2.18	0.00	0.000000	0.00	0.00
1983	TO 2007	7.61	0.005210	387.85	2.04	7.53	0.004800	312.14	1.94	0.00	0.000000	0.00	0.00
1982	TO 2007	7.62	0.005151	387.24	2.05	7.55	0.004751	311.12	1.96	0.00	0.000000	0.00	0.00
1981	TO 2007	7.62	0.005110	387.34	2.05	7.56	0.004714	310.95	1.97	0.00	0.000000	0.00	0.00
1980	TO 2007	7.61	0.005100	387.43	2.05	7.56	0.004702	310.91	1.97	0.00	0.000000	0.00	0.00
1979	TO 2007	7.61	0.005095	387.41	2.05	7.56	0.004698	310.85	1.97	0.00	0.000000	0.00	0.00
1978	TO 2007	7.61	0.005095	387.41	2.05	7.56	0.004698	310.85	1.97	0.00	0.000000	0.00	0.00
1977	TO 2007	7.61	0.005096	387.51	2.05	7.56	0.004701	310.93	1.97	0.00	0.000000	0.00	0.00
1976	TO 2007	7.61	0.005096	387.50	2.05	7.56	0.004701	310.91	1.97	0.00	0.000000	0.00	0.00
1975	TO 2007	7.61	0.005101	387.49	2.05	7.56	0.004707	310.87	1.97	0.00	0.000000	0.00	0.00

ORANGE AND ROCKLAND UTILITIES INC. MORTALITY STUDY BY LEAST SQUARE FITTING OF WEIGHTED RETIREMENT RATIOS
ACCOUNT 3392300 TRANS. EQUIP. OTHER VEH. PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2007

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
1976 TO 1985		23.71	0.003944	318.41	1.99	23.55	0.003987	290.85	2.15	0.00	0.000000	0.00	0.00
1977 TO 1986		25.63	0.003577	325.79	1.94	25.12	0.003614	288.63	2.14	0.00	0.000000	0.00	0.00
1978 TO 1987		23.70	0.003241	322.72	1.97	23.51	0.003275	308.33	2.04	0.00	0.000000	0.00	0.00
1979 TO 1988		31.14	0.003327	374.16	1.31	24.18	0.003266	237.81	2.29	0.00	0.000000	0.00	0.00
1980 TO 1989		18.76	0.003429	349.17	1.59	18.35	0.003456	313.34	1.73	0.00	0.000000	0.00	0.00
1981 TO 1990		16.58	0.003740	328.73	1.84	16.53	0.003777	323.71	1.86	0.00	0.000000	0.00	0.00
1982 TO 1991		12.31	0.009319	288.30	2.33	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1983 TO 1992		11.33	0.010092	304.40	2.50	11.34	0.010207	304.15	2.52	0.00	0.000000	0.00	0.00
1984 TO 1993		10.82	0.011102	318.87	2.64	10.86	0.011223	317.81	2.69	0.00	0.000000	0.00	0.00
1985 TO 1994		11.27	0.010075	306.13	2.58	11.31	0.010180	304.97	2.68	0.00	0.000000	0.00	0.00
1986 TO 1995		11.01	0.009503	313.48	2.60	11.05	0.009598	312.22	2.69	0.00	0.000000	0.00	0.00
1987 TO 1996		11.54	0.008337	299.04	2.56	11.57	0.008433	298.26	2.74	0.00	0.000000	0.00	0.00
1988 TO 1997		10.79	0.009409	319.64	2.67	10.83	0.009521	309.18	2.73	0.00	0.000000	0.00	0.00
1989 TO 1998		11.25	0.008839	306.58	2.68	11.27	0.008958	306.00	2.75	0.00	0.000000	0.00	0.00
1990 TO 1999		11.95	0.008035	288.70	2.63	11.96	0.008135	288.57	2.65	0.00	0.000000	0.00	0.00
1991 TO 2000		10.99	0.011327	313.96	2.88	11.06	0.011441	293.93	2.96	0.00	0.000000	0.00	0.00
1992 TO 2001		11.86	0.010445	290.95	2.78	11.90	0.010571	289.88	2.88	0.00	0.000000	0.00	0.00
1993 TO 2002		12.94	0.008130	274.25	2.67	12.95	0.008238	266.51	2.73	0.00	0.000000	0.00	0.00
1994 TO 2003		13.51	0.007211	277.54	2.61	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1995 TO 2004		12.72	0.008470	271.19	2.87	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1996 TO 2005		13.54	0.007689	269.52	2.77	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1997 TO 2006		12.60	0.009897	273.79	2.92	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1998 TO 2007		12.87	0.010241	268.05	2.92	12.92	0.010377	267.12	2.97	0.00	0.000000	0.00	0.00

ORANGE AND ROCKLAND UTILITIES INC. MORTALITY STUDY BY LEAST SQUARE FITTING OF WEIGHTED RETIREMENT RATIOS
ACCOUNT 3392300 TRANS. EQUIP. OTHER VEH. PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2007

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)
2007	TO 2007	10.19	0.025695	338.68	2.42	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
2006	TO 2007	9.46	0.024299	343.56	2.57	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
2005	TO 2007	11.35	0.015900	304.03	2.54	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
2004	TO 2007	11.02	0.016138	313.14	2.69	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
2003	TO 2007	11.57	0.013268	298.09	2.74	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
2002	TO 2007	12.54	0.011728	275.07	2.86	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
2001	TO 2007	13.16	0.010681	262.13	2.92	13.18	0.010804	261.67	2.94	0.00	0.000000	0.00	0.00
2000	TO 2007	12.24	0.011521	281.78	2.98	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1999	TO 2007	12.59	0.010688	274.03	2.93	12.60	0.010797	273.83	2.94	0.00	0.000000	0.00	0.00
1998	TO 2007	12.87	0.010241	268.05	2.92	12.92	0.010377	267.12	2.97	0.00	0.000000	0.00	0.00
1997	TO 2007	12.39	0.009418	278.52	2.86	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1996	TO 2007	12.60	0.009057	273.72	2.87	12.61	0.009151	273.56	2.88	0.00	0.000000	0.00	0.00
1995	TO 2007	12.42	0.008673	277.68	2.82	12.43	0.008753	277.66	2.82	0.00	0.000000	0.00	0.00
1994	TO 2007	12.51	0.008396	275.83	2.78	12.53	0.008503	275.29	2.81	0.00	0.000000	0.00	0.00
1993	TO 2007	12.31	0.008422	280.35	2.77	12.34	0.008532	279.67	2.80	0.00	0.000000	0.00	0.00
1992	TO 2007	12.13	0.008597	284.37	2.77	12.16	0.008702	283.80	2.79	0.00	0.000000	0.00	0.00
1991	TO 2007	11.93	0.008672	289.09	2.77	11.94	0.008758	288.93	2.77	0.00	0.000000	0.00	0.00
1990	TO 2007	11.95	0.008444	288.71	2.74	11.96	0.008535	288.40	2.76	0.00	0.000000	0.00	0.00
1989	TO 2007	11.92	0.008275	289.42	2.70	11.94	0.008368	289.05	2.72	0.00	0.000000	0.00	0.00
1988	TO 2007	11.95	0.008304	288.68	2.67	11.99	0.008418	287.76	2.70	0.00	0.000000	0.00	0.00
1987	TO 2007	11.99	0.008253	287.69	2.67	12.03	0.008367	286.78	2.71	0.00	0.000000	0.00	0.00
1986	TO 2007	12.03	0.008213	286.88	2.67	12.06	0.008326	286.04	2.71	0.00	0.000000	0.00	0.00
1985	TO 2007	12.05	0.008158	286.35	2.67	12.08	0.008269	285.55	2.71	0.00	0.000000	0.00	0.00
1984	TO 2007	12.06	0.008100	286.11	2.67	12.09	0.008208	285.36	2.70	0.00	0.000000	0.00	0.00
1983	TO 2007	12.05	0.008039	286.33	2.66	12.08	0.008147	285.51	2.69	0.00	0.000000	0.00	0.00
1982	TO 2007	12.05	0.008010	286.28	2.65	12.08	0.008115	285.53	2.69	0.00	0.000000	0.00	0.00
1981	TO 2007	12.05	0.007985	286.34	2.64	12.08	0.008088	285.62	2.68	0.00	0.000000	0.00	0.00
1980	TO 2007	12.04	0.007965	286.47	2.63	12.07	0.008068	285.72	2.66	0.00	0.000000	0.00	0.00
1979	TO 2007	12.05	0.007959	286.34	2.63	12.08	0.008060	285.67	2.66	0.00	0.000000	0.00	0.00
1978	TO 2007	12.05	0.007963	286.22	2.63	12.08	0.008062	285.63	2.65	0.00	0.000000	0.00	0.00
1977	TO 2007	12.06	0.007971	286.13	2.63	12.08	0.008067	285.60	2.65	0.00	0.000000	0.00	0.00
1976	TO 2007	12.06	0.007975	286.07	2.63	12.08	0.008070	285.59	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 3393000 STORES EQUIPMENT PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2007
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
1953 TO 1962	1953 TO 1962	51.09	0.002211	325.93	1.95	43.89	0.002067	199.36	3.61	42.43	0.002021	161.46	4.97
1954 TO 1963	1954 TO 1963	55.07	0.003336	436.68	0.71	40.36	0.003069	201.91	2.50	0.00	0.000000	0.00	0.00
1955 TO 1964	1955 TO 1964	59.40	0.003111	441.93	0.67	42.04	0.002912	203.37	2.48	0.00	0.000000	0.00	0.00
1956 TO 1965	1956 TO 1965	39.86	0.005255	568.29	-0.40	0.00	0.000000	0.00	0.00	32.53	0.005335	225.96	1.27
1957 TO 1966	1957 TO 1966	43.06	0.004883	565.49	-0.37	0.00	0.000000	0.00	0.00	34.35	0.004958	222.68	1.33
1958 TO 1967	1958 TO 1967	45.89	0.004580	567.67	-0.38	0.00	0.000000	0.00	0.00	36.18	0.004659	225.27	1.34
1959 TO 1968	1959 TO 1968	48.96	0.004354	566.80	-0.38	0.00	0.000000	0.00	0.00	38.22	0.004434	228.96	1.34
1960 TO 1969	1960 TO 1969	51.09	0.003943	558.82	-0.30	0.00	0.000000	0.00	0.00	40.60	0.004020	237.68	1.27
1961 TO 1970	1961 TO 1970	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00	42.41	0.004527	208.69	1.55
1962 TO 1971	1962 TO 1971	0.00	0.000000	0.00	0.00	66.07	0.004425	377.65	-0.03	44.36	0.004460	208.52	1.54
1963 TO 1972	1963 TO 1972	0.00	0.000000	0.00	0.00	119.96	0.003517	269.68	0.35	48.37	0.003537	193.30	1.72
1964 TO 1973	1964 TO 1973	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00	51.75	0.002977	171.03	2.39
1965 TO 1974	1965 TO 1974	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00	53.33	0.002608	169.70	2.44
1966 TO 1975	1966 TO 1975	230.44	0.000571	172.93	1.65	97.50	0.000571	222.05	2.91	0.00	0.000000	0.00	0.00
1967 TO 1976	1967 TO 1976	0.00	0.000000	0.00	0.00	158.21	0.001734	222.18	2.11	65.10	0.001732	163.60	3.23
1968 TO 1977	1968 TO 1977	0.00	0.000000	0.00	0.00	139.98	0.001668	223.24	2.19	67.39	0.001668	165.45	3.25
1969 TO 1978	1969 TO 1978	0.00	0.000000	0.00	0.00	130.24	0.001656	221.51	2.28	69.77	0.001659	165.54	3.27
1970 TO 1979	1970 TO 1979	0.00	0.000000	0.00	0.00	125.29	0.001680	215.10	2.45	71.45	0.001684	164.45	3.33
1971 TO 1980	1971 TO 1980	0.00	0.000000	0.00	0.00	192.00	0.001248	188.80	3.04	72.96	0.001243	159.67	3.58
1972 TO 1981	1972 TO 1981	52.68	0.004860	369.22	1.40	0.00	0.000000	0.00	0.00	48.09	0.004897	190.28	2.18
1973 TO 1982	1973 TO 1982	25.91	0.008863	353.17	1.55	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1974 TO 1983	1974 TO 1983	24.38	0.010123	358.93	1.47	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1975 TO 1984	1975 TO 1984	24.76	0.009616	357.42	1.51	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1976 TO 1985	1976 TO 1985	25.20	0.009150	355.16	1.56	0.00	0.000000	0.00	0.00	22.66	0.010033	412.54	1.68
1977 TO 1986	1977 TO 1986	24.11	0.009977	329.74	1.87	0.00	0.000000	0.00	0.00	19.11	0.009564	384.56	1.85
1978 TO 1987	1978 TO 1987	20.31	0.009650	327.36	1.87	0.00	0.000000	0.00	0.00	19.24	0.009401	371.67	1.96
1979 TO 1988	1979 TO 1988	20.26	0.009356	323.23	1.97	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1980 TO 1989	1980 TO 1989	20.15	0.008397	315.18	2.06	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1981 TO 1990	1981 TO 1990	20.06	0.008549	306.57	2.15	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1982 TO 1991	1982 TO 1991	20.84	0.006992	304.70	2.20	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1983 TO 1992	1983 TO 1992	26.56	0.005280	310.61	2.13	27.83	0.005269	256.93	2.42	27.98	0.005291	248.41	2.27
1984 TO 1993	1984 TO 1993	25.86	0.005596	326.75	1.92	26.03	0.005644	297.72	2.01	26.59	0.005588	246.30	1.87
1985 TO 1994	1985 TO 1994	25.86	0.005562	334.43	1.80	25.90	0.005602	299.19	1.90	26.95	0.005495	235.66	1.80
1986 TO 1995	1986 TO 1995	27.33	0.005269	338.43	1.76	27.21	0.005320	314.17	1.84	28.01	0.005273	226.74	1.91
1987 TO 1996	1987 TO 1996	30.95	0.004262	350.60	1.59	0.00	0.000000	0.00	0.00	31.36	0.004240	212.02	1.94
1988 TO 1997	1988 TO 1997	70.85	0.002751	476.36	0.37	0.00	0.000000	0.00	0.00	50.61	0.002692	164.98	2.50
1989 TO 1998	1989 TO 1998	100.82	0.002508	395.26	-0.88	0.00	0.000000	0.00	0.00	51.78	0.002458	163.19	2.64
1990 TO 1999	1990 TO 1999	22.08	0.008358	423.53	0.83	0.00	0.000000	0.00	0.00	53.21	0.008000	421.94	-2.60
1991 TO 2000	1991 TO 2000	21.30	0.008712	382.68	1.24	0.00	0.000000	0.00	0.00	53.21	0.008729	312.70	1.27
1992 TO 2001	1992 TO 2001	21.40	0.008548	390.21	1.13	0.00	0.000000	0.00	0.00	22.55	0.008729	312.70	1.27
1993 TO 2002	1993 TO 2002	21.44	0.007381	408.16	0.97	0.00	0.000000	0.00	0.00	22.78	0.008606	313.85	1.26
1994 TO 2003	1994 TO 2003	22.33	0.008642	356.07	1.52	22.02	0.008715	338.38	1.45	22.98	0.007436	311.21	1.19
1995 TO 2004	1995 TO 2004	22.97	0.008751	324.39	1.96	22.46	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1996 TO 2005	1996 TO 2005	21.17	0.009012	309.34	2.12	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1997 TO 2006	1997 TO 2006	18.72	0.012058	323.23	1.92	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1998 TO 2007	1998 TO 2007	18.27	0.012346	331.10	1.84	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
ACCOUNT 3393000 STORES EQUIPMENT PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2007

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)	EQUIV. H CURVE	
2007 TO 2007	2007 TO 2007	38.02	0.006269	314.28	2.10	36.21	0.006234	211.26	3.41	0.00	0.000000	0.00	0.000000	0.00
2006 TO 2007	2006 TO 2007	16.24	0.025277	348.01	1.60	0.00	0.000000	0.00	0.00	14.74	0.025296	647.68	-0.31	0.00
2005 TO 2007	2005 TO 2007	15.91	0.022425	323.60	1.90	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.000000	0.00
2004 TO 2007	2004 TO 2007	18.00	0.019523	308.28	2.17	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.000000	0.00
2003 TO 2007	2003 TO 2007	19.02	0.016659	291.84	2.37	19.07	0.016801	291.04	2.38	0.00	0.000000	0.00	0.000000	0.00
2002 TO 2007	2002 TO 2007	20.52	0.014091	290.03	2.40	20.56	0.014213	284.46	2.41	0.00	0.000000	0.00	0.000000	0.00
2001 TO 2007	2001 TO 2007	21.72	0.013338	287.71	2.45	21.78	0.013455	282.41	2.48	0.00	0.000000	0.00	0.000000	0.00
2000 TO 2007	2000 TO 2007	22.21	0.012919	272.46	2.68	22.71	0.013003	244.43	2.85	0.00	0.000000	0.00	0.000000	0.00
1999 TO 2007	1999 TO 2007	17.06	0.013483	337.08	1.74	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.000000	0.00
1998 TO 2007	1998 TO 2007	18.27	0.012346	331.10	1.84	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.000000	0.00
1997 TO 2007	1997 TO 2007	19.28	0.011458	324.18	1.91	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.000000	0.00
1996 TO 2007	1996 TO 2007	20.12	0.010607	320.54	1.97	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.000000	0.00
1995 TO 2007	1995 TO 2007	20.78	0.010083	320.02	2.01	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.000000	0.00
1994 TO 2007	1994 TO 2007	20.88	0.009591	323.21	1.92	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.000000	0.00
1993 TO 2007	1993 TO 2007	20.44	0.009004	335.17	1.78	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.000000	0.00
1992 TO 2007	1992 TO 2007	20.92	0.008654	332.18	1.83	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.000000	0.00
1991 TO 2007	1991 TO 2007	21.33	0.008257	330.58	1.87	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.000000	0.00
1990 TO 2007	1990 TO 2007	21.65	0.007860	325.58	1.90	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.000000	0.00
1989 TO 2007	1989 TO 2007	21.91	0.007672	326.27	1.92	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.000000	0.00
1988 TO 2007	1988 TO 2007	22.12	0.007440	323.16	1.93	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.000000	0.00
1987 TO 2007	1987 TO 2007	21.52	0.007339	318.35	1.99	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.000000	0.00
1986 TO 2007	1986 TO 2007	21.49	0.007363	318.79	2.04	21.49	0.007424	314.12	2.04	0.00	0.000000	0.00	0.000000	0.00
1985 TO 2007	1985 TO 2007	21.68	0.007190	320.61	2.00	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.000000	0.00
1984 TO 2007	1984 TO 2007	21.85	0.007079	322.61	1.98	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.000000	0.00
1983 TO 2007	1983 TO 2007	21.83	0.007145	322.91	1.96	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.000000	0.00
1982 TO 2007	1982 TO 2007	21.16	0.007382	319.04	2.01	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.000000	0.00
1981 TO 2007	1981 TO 2007	21.17	0.007190	318.83	2.01	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.000000	0.00
1980 TO 2007	1980 TO 2007	21.38	0.007150	320.37	1.98	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.000000	0.00
1979 TO 2007	1979 TO 2007	21.58	0.006985	322.12	1.96	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.000000	0.00
1978 TO 2007	1978 TO 2007	21.75	0.006949	324.07	1.94	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.000000	0.00
1977 TO 2007	1977 TO 2007	21.91	0.006920	326.29	1.92	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.000000	0.00
1976 TO 2007	1976 TO 2007	21.99	0.006870	325.13	1.89	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.000000	0.00
1975 TO 2007	1975 TO 2007	22.13	0.006774	327.67	1.88	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.000000	0.00
1974 TO 2007	1974 TO 2007	22.25	0.006731	330.35	1.87	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.000000	0.00
1973 TO 2007	1973 TO 2007	22.36	0.006705	328.67	1.86	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.000000	0.00
1972 TO 2007	1972 TO 2007	22.47	0.006675	331.57	1.85	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.000000	0.00
1971 TO 2007	1971 TO 2007	22.56	0.006662	330.25	1.84	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.000000	0.00
1970 TO 2007	1970 TO 2007	22.63	0.006581	333.56	1.84	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.000000	0.00
1969 TO 2007	1969 TO 2007	22.72	0.006478	332.38	1.83	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.000000	0.00
1968 TO 2007	1968 TO 2007	22.79	0.006437	331.28	1.83	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.000000	0.00
1967 TO 2007	1967 TO 2007	22.86	0.006383	334.67	1.82	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.000000	0.00
1966 TO 2007	1966 TO 2007	22.92	0.006350	333.78	1.82	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.000000	0.00
1965 TO 2007	1965 TO 2007	22.84	0.006323	334.92	1.80	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.000000	0.00
1964 TO 2007	1964 TO 2007	22.90	0.006311	334.11	1.80	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.000000	0.00
1963 TO 2007	1963 TO 2007	22.88	0.006285	334.32	1.78	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.000000	0.00
1962 TO 2007	1962 TO 2007	22.91	0.006270	338.21	1.78	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.000000	0.00
1961 TO 2007	1961 TO 2007	22.96	0.006234	337.60	1.78	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.000000	0.00
1960 TO 2007	1960 TO 2007	22.98	0.006214	337.31	1.78	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.000000	0.00
1959 TO 2007	1959 TO 2007	23.01	0.006208	336.75	1.78	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.000000	0.00
1958 TO 2007	1958 TO 2007	23.05	0.006197	336.24	1.78	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.000000	0.00
1957 TO 2007	1957 TO 2007	23.08	0.006186	335.79	1.78	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.000000	0.00
1956 TO 2007	1956 TO 2007	23.11	0.006148	335.42	1.78	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.000000	0.00
1955 TO 2007	1955 TO 2007	23.13	0.006130	335.04	1.77	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.000000	0.00

ORANGE AND ROCKLAND UTILITIES INC. MORTALITY STUDY BY LEAST SQUARE FITTING OF WEIGHTED RETIREMENT RATIOS
ACCOUNT 3393000 STORES EQUIPMENT PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2007
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)
1954 TO 2007		23.15	0.006108	334.72	1.77	0.00	0.000000	0.00	0.00	0.00
1953 TO 2007		23.17	0.006102	338.82	1.77	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 3394000 TOOLS AND SHOP EQUIPMENT PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2007
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	18.94	0.006547	620.48	-0.86	0.00	0.000000	0.00	0.00	17.93	0.006287	393.14	-0.85	
1953 TO 1962	1953 TO 1962	18.87	0.006461	606.81	-0.73	0.00	0.000000	0.00	0.00	18.01	0.006198	380.44	-0.66	
1954 TO 1963	1954 TO 1963	14.28	0.006539	808.71	-2.60	0.00	0.000000	0.00	0.00	13.86	0.006201	501.38	-2.33	
1955 TO 1964	1955 TO 1964	14.85	0.005962	872.21	-2.60	0.00	0.000000	0.00	0.00	14.47	0.005641	480.35	-2.60	
1956 TO 1965	1956 TO 1965	15.55	0.005289	987.43	-2.60	0.00	0.000000	0.00	0.00	15.27	0.004851	428.85	-2.60	
1957 TO 1966	1957 TO 1966	16.61	0.004579	869.71	-2.60	0.00	0.000000	0.00	0.00	16.38	0.004231	424.38	-2.40	
1958 TO 1967	1958 TO 1967	17.51	0.004272	819.70	-2.60	0.00	0.000000	0.00	0.00	17.35	0.004060	412.02	-1.94	
1959 TO 1968	1959 TO 1968	18.98	0.004052	861.65	-2.60	0.00	0.000000	0.00	0.00	18.78	0.003897	386.05	-1.78	
1960 TO 1969	1960 TO 1969	20.47	0.003724	764.62	-2.32	0.00	0.000000	0.00	0.00	20.37	0.003590	370.62	-1.28	
1961 TO 1970	1961 TO 1970	24.59	0.002753	685.28	-1.43	0.00	0.000000	0.00	0.00	24.48	0.002717	377.91	-0.93	
1962 TO 1971	1962 TO 1971	30.59	0.002324	930.09	-2.60	0.00	0.000000	0.00	0.00	28.69	0.002327	346.85	-0.75	
1963 TO 1972	1963 TO 1972	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00	37.58	0.001995	400.53	-2.37	
1964 TO 1973	1964 TO 1973	54.02	0.001883	485.92	0.30	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00	
1965 TO 1974	1965 TO 1974	57.55	0.001346	431.77	0.77	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00	
1966 TO 1975	1966 TO 1975	36.30	0.002352	411.89	0.95	0.00	0.000000	0.00	0.00	38.96	0.002143	245.15	0.98	
1967 TO 1976	1967 TO 1976	35.63	0.002365	411.17	0.95	0.00	0.000000	0.00	0.00	38.67	0.002158	252.13	0.91	
1968 TO 1977	1968 TO 1977	32.17	0.002560	436.73	0.71	0.00	0.000000	0.00	0.00	36.27	0.002117	255.04	0.57	
1969 TO 1978	1969 TO 1978	34.03	0.002384	442.31	0.67	0.00	0.000000	0.00	0.00	38.48	0.001965	240.38	0.70	
1970 TO 1979	1970 TO 1979	35.15	0.002216	445.19	0.63	0.00	0.000000	0.00	0.00	39.93	0.001828	239.19	0.73	
1971 TO 1980	1971 TO 1980	39.50	0.002163	472.10	0.42	0.00	0.000000	0.00	0.00	43.78	0.001860	215.85	0.98	
1972 TO 1981	1972 TO 1981	36.76	0.002220	482.88	0.33	0.00	0.000000	0.00	0.00	41.92	0.001826	227.84	0.71	
1973 TO 1982	1973 TO 1982	38.03	0.002154	490.35	0.25	0.00	0.000000	0.00	0.00	42.85	0.001742	222.89	0.73	
1974 TO 1983	1974 TO 1983	29.71	0.002977	435.89	0.73	0.00	0.000000	0.00	0.00	35.79	0.002444	289.20	-0.26	
1975 TO 1984	1975 TO 1984	30.98	0.002881	434.14	0.73	0.00	0.000000	0.00	0.00	37.09	0.002342	273.69	-0.13	
1976 TO 1985	1976 TO 1985	39.35	0.002562	407.92	0.99	0.00	0.000000	0.00	0.00	50.54	0.002286	236.44	0.36	
1977 TO 1986	1977 TO 1986	15.03	0.005807	435.73	0.71	0.00	0.000000	0.00	0.00	15.13	0.005534	525.36	1.08	
1978 TO 1987	1978 TO 1987	15.76	0.005619	415.73	0.91	0.00	0.000000	0.00	0.00	15.71	0.005383	505.93	1.22	
1979 TO 1988	1979 TO 1988	16.00	0.005466	396.94	1.05	0.00	0.000000	0.00	0.00	15.80	0.005202	490.44	1.34	
1980 TO 1989	1980 TO 1989	16.27	0.005527	384.09	1.18	0.00	0.000000	0.00	0.00	15.98	0.005289	472.51	1.44	
1981 TO 1990	1981 TO 1990	16.51	0.005503	372.52	1.32	0.00	0.000000	0.00	0.00	16.11	0.005278	456.14	1.54	
1982 TO 1991	1982 TO 1991	17.07	0.005165	354.44	1.49	0.00	0.000000	0.00	0.00	16.62	0.005008	424.09	1.65	
1983 TO 1992	1983 TO 1992	17.06	0.005079	348.70	1.58	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00	
1984 TO 1993	1984 TO 1993	17.83	0.004016	344.97	1.66	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00	
1985 TO 1994	1985 TO 1994	18.13	0.003809	333.78	1.80	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00	
1986 TO 1995	1986 TO 1995	18.36	0.003539	324.11	1.92	18.46	0.003570	316.93	1.92	0.00	0.000000	0.00	0.00	
1987 TO 1996	1987 TO 1996	94.44	0.000385	376.45	1.32	0.00	0.000000	0.00	0.00	91.39	0.000391	264.25	1.69	
1988 TO 1997	1988 TO 1997	106.30	0.000382	374.87	1.10	0.00	0.000000	0.00	0.00	73.82	0.000384	191.68	2.64	
1989 TO 1998	1989 TO 1998	29.44	0.003678	358.30	1.50	0.00	0.000000	0.00	0.00	31.39	0.003612	275.60	1.14	
1990 TO 1999	1990 TO 1999	30.98	0.003519	363.09	1.44	0.00	0.000000	0.00	0.00	33.18	0.003480	266.76	1.22	
1991 TO 2000	1991 TO 2000	24.71	0.003188	325.74	1.95	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00	
1992 TO 2001	1992 TO 2001	24.14	0.003077	321.08	2.00	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00	
1993 TO 2002	1993 TO 2002	23.04	0.003250	314.73	2.07	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00	
1994 TO 2003	1994 TO 2003	22.70	0.003341	314.98	2.07	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00	
1995 TO 2004	1995 TO 2004	22.62	0.003409	316.11	2.06	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00	
1996 TO 2005	1996 TO 2005	22.59	0.003310	312.07	2.09	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00	
1997 TO 2006	1997 TO 2006	21.83	0.003371	309.25	2.12	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00	
1998 TO 2007	1998 TO 2007	21.19	0.003456	309.10	2.12	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
ACCOUNT 3394000 TOOLS AND SHOP EQUIPMENT PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2007

SUMMARY OF SHRINKING BANDS

YEAR	YEAR	AVERAGE SERVICE LIFE (YEARS)	FIRST DEGREE			SECOND DEGREE			THIRD DEGREE				
			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
2007 TO 2007	2007 TO 2007	21.11	0.004965	338.78	1.71	0.00	0.000000	0.00	0.00	28.65	0.004509	595.15	-2.60
2006 TO 2007	2006 TO 2007	21.46	0.004012	323.84	1.96	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
2005 TO 2007	2005 TO 2007	23.34	0.003461	319.20	2.03	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
2004 TO 2007	2004 TO 2007	24.26	0.003185	319.45	1.99	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
2003 TO 2007	2003 TO 2007	24.02	0.003024	322.61	1.95	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
2002 TO 2007	2002 TO 2007	23.15	0.003444	321.86	1.96	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
2001 TO 2007	2001 TO 2007	23.31	0.003622	319.58	2.01	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
2000 TO 2007	2000 TO 2007	22.01	0.003334	302.09	2.27	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1999 TO 2007	1999 TO 2007	22.83	0.003179	304.42	2.22	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1998 TO 2007	1998 TO 2007	21.19	0.003456	309.10	2.12	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1997 TO 2007	1997 TO 2007	21.78	0.003237	314.53	2.08	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1996 TO 2007	1996 TO 2007	22.35	0.003058	315.45	2.06	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1995 TO 2007	1995 TO 2007	22.83	0.002913	317.55	2.05	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1994 TO 2007	1994 TO 2007	23.25	0.002836	316.19	2.04	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1993 TO 2007	1993 TO 2007	23.46	0.002716	317.58	2.02	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1992 TO 2007	1992 TO 2007	23.65	0.002646	319.27	1.99	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1991 TO 2007	1991 TO 2007	23.91	0.002581	319.99	1.98	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1990 TO 2007	1990 TO 2007	24.14	0.002542	321.05	1.97	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1989 TO 2007	1989 TO 2007	24.34	0.002514	322.53	1.97	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1988 TO 2007	1988 TO 2007	24.51	0.002470	324.35	1.96	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1987 TO 2007	1987 TO 2007	24.64	0.002436	322.60	1.96	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1986 TO 2007	1986 TO 2007	21.11	0.002532	319.81	2.00	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1985 TO 2007	1985 TO 2007	21.43	0.002474	319.59	1.97	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1984 TO 2007	1984 TO 2007	21.73	0.002438	324.43	1.94	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1983 TO 2007	1983 TO 2007	21.68	0.002473	325.14	1.94	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1982 TO 2007	1982 TO 2007	21.91	0.002436	326.33	1.91	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1981 TO 2007	1981 TO 2007	22.03	0.002465	329.12	1.89	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1980 TO 2007	1980 TO 2007	22.24	0.002424	330.55	1.87	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1979 TO 2007	1979 TO 2007	22.40	0.002413	328.18	1.86	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1978 TO 2007	1978 TO 2007	22.57	0.002402	330.10	1.85	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1977 TO 2007	1977 TO 2007	22.55	0.002403	334.75	1.82	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1976 TO 2007	1976 TO 2007	22.63	0.002371	333.70	1.81	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1975 TO 2007	1975 TO 2007	22.47	0.002328	336.07	1.79	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1974 TO 2007	1974 TO 2007	22.60	0.002302	334.10	1.79	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1973 TO 2007	1973 TO 2007	22.72	0.002290	336.74	1.78	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1972 TO 2007	1972 TO 2007	22.83	0.002274	335.12	1.78	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1971 TO 2007	1971 TO 2007	22.93	0.002264	338.06	1.78	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1970 TO 2007	1970 TO 2007	22.97	0.002253	337.43	1.78	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1969 TO 2007	1969 TO 2007	23.03	0.002242	336.55	1.78	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1968 TO 2007	1968 TO 2007	23.09	0.002233	335.69	1.77	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1967 TO 2007	1967 TO 2007	23.12	0.002220	335.14	1.77	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1966 TO 2007	1966 TO 2007	23.15	0.002213	339.11	1.76	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1965 TO 2007	1965 TO 2007	23.11	0.002206	339.64	1.75	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1964 TO 2007	1964 TO 2007	23.11	0.002200	339.63	1.73	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1963 TO 2007	1963 TO 2007	22.85	0.002189	343.55	1.66	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1962 TO 2007	1962 TO 2007	22.84	0.002175	343.70	1.66	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1961 TO 2007	1961 TO 2007	22.83	0.002168	343.90	1.65	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1960 TO 2007	1960 TO 2007	22.70	0.002154	345.76	1.63	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1959 TO 2007	1959 TO 2007	22.70	0.002153	350.29	1.61	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1958 TO 2007	1958 TO 2007	22.71	0.002150	350.05	1.61	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1957 TO 2007	1957 TO 2007	22.72	0.002142	349.86	1.60	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1956 TO 2007	1956 TO 2007	22.70	0.002133	350.15	1.59	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1955 TO 2007	1955 TO 2007	22.67	0.002129	350.75	1.59	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
ACCOUNT 3394000 TOOLS AND SHOP EQUIPMENT PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2007
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)
1954 TO 2007		22.66	0.002125	350.77	1.58	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1953 TO 2007		22.66	0.002122	350.85	1.58	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1952 TO 2007		22.67	0.002124	350.74	1.57	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
ACCOUNT 3395000 LABORATORY EQUIPMENT PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2007
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	40.64	0.002578	340.77	1.75	39.69	0.002594	275.92	2.08	0.00	0.000000	0.00	0.00
1953 TO 1962	1953 TO 1962	37.88	0.002391	339.23	1.77	37.79	0.002415	326.80	1.82	0.00	0.000000	0.00	0.00
1954 TO 1963	1954 TO 1963	33.21	0.003616	435.06	0.74	32.73	0.003646	368.14	0.94	0.00	0.000000	0.00	0.00
1955 TO 1964	1955 TO 1964	33.10	0.003505	415.35	0.90	32.58	0.003527	336.14	1.15	0.00	0.000000	0.00	0.00
1956 TO 1965	1956 TO 1965	33.86	0.003190	417.91	0.88	33.71	0.003219	396.00	0.94	0.00	0.000000	0.00	0.00
1957 TO 1966	1957 TO 1966	35.23	0.003200	418.62	0.89	35.20	0.003229	413.32	0.90	0.00	0.000000	0.00	0.00
1958 TO 1967	1958 TO 1967	34.09	0.003787	385.72	1.19	33.64	0.003796	301.73	1.45	0.00	0.000000	0.00	0.00
1959 TO 1968	1959 TO 1968	35.98	0.003619	384.98	1.21	35.37	0.003633	303.89	1.49	0.00	0.000000	0.00	0.00
1960 TO 1969	1960 TO 1969	35.22	0.003550	393.30	1.14	35.01	0.003579	358.44	1.23	0.00	0.000000	0.00	0.00
1961 TO 1970	1961 TO 1970	44.55	0.003105	418.67	0.89	42.73	0.003128	326.44	1.33	41.14	0.003150	246.71	1.54
1962 TO 1971	1962 TO 1971	49.95	0.002602	417.43	0.90	47.14	0.002620	319.28	1.33	44.52	0.002635	230.25	1.71
1963 TO 1972	1963 TO 1972	59.94	0.002277	424.57	0.83	52.51	0.002289	282.82	1.59	49.26	0.002301	214.15	1.97
1964 TO 1973	1964 TO 1973	65.69	0.001700	350.89	1.61	61.04	0.001712	279.33	2.04	57.40	0.001724	215.17	2.47
1965 TO 1974	1965 TO 1974	66.49	0.001725	370.76	1.37	0.00	0.000000	0.00	0.00	56.40	0.001723	192.39	2.30
1966 TO 1975	1966 TO 1975	74.72	0.001487	371.41	1.37	0.00	0.000000	0.00	0.00	60.31	0.001484	184.87	2.51
1967 TO 1976	1967 TO 1976	73.65	0.001372	374.08	1.35	0.00	0.000000	0.00	0.00	61.60	0.001364	189.13	2.36
1968 TO 1977	1968 TO 1977	109.25	0.001020	364.76	1.01	0.00	0.000000	0.00	0.00	71.71	0.000959	165.25	2.78
1969 TO 1978	1969 TO 1978	122.17	0.000890	326.19	0.96	0.00	0.000000	0.00	0.00	73.84	0.000833	163.18	2.95
1970 TO 1979	1970 TO 1979	154.03	0.000607	258.71	1.18	0.00	0.000000	0.00	0.00	84.31	0.000574	160.71	3.45
1971 TO 1980	1971 TO 1980	171.23	0.000528	232.73	1.27	0.00	0.000000	0.00	0.00	89.45	0.000501	160.43	3.65
1972 TO 1981	1972 TO 1981	183.94	0.000615	216.65	1.07	0.00	0.000000	0.00	0.00	83.97	0.000581	160.17	3.49
1973 TO 1982	1973 TO 1982	194.77	0.000554	204.60	1.15	0.00	0.000000	0.00	0.00	86.24	0.000522	159.44	3.59
1974 TO 1983	1974 TO 1983	198.70	0.000467	200.55	1.26	0.00	0.000000	0.00	0.00	89.24	0.000438	159.68	3.73
1975 TO 1984	1975 TO 1984	283.64	0.000222	140.50	2.19	0.00	0.000000	0.00	0.00	106.41	0.000214	162.11	4.39
1976 TO 1985	1976 TO 1985	288.30	0.000207	138.23	2.27	0.00	0.000000	0.00	0.00	108.17	0.000200	161.32	4.46
1977 TO 1986	1977 TO 1986	0.00	0.000000	0.00	0.00	45.16	0.004570	246.92	0.12	0.00	0.000000	0.00	0.00
1978 TO 1987	1978 TO 1987	0.00	0.000000	0.00	0.00	47.39	0.004146	243.72	0.32	0.00	0.000000	0.00	0.00
1979 TO 1988	1979 TO 1988	0.00	0.000000	0.00	0.00	50.47	0.003670	236.80	0.57	0.00	0.000000	0.00	0.00
1980 TO 1989	1980 TO 1989	0.00	0.000000	0.00	0.00	51.88	0.003680	231.90	0.66	0.00	0.000000	0.00	0.00
1981 TO 1990	1981 TO 1990	0.00	0.000000	0.00	0.00	53.69	0.003402	231.90	0.80	0.00	0.000000	0.00	0.00
1982 TO 1991	1982 TO 1991	25.11	0.004107	464.02	0.46	26.12	0.003843	315.86	0.67	0.00	0.000000	0.00	0.00
1983 TO 1992	1983 TO 1992	23.87	0.004042	446.10	0.63	24.76	0.003804	321.08	0.73	0.00	0.000000	0.00	0.00
1984 TO 1993	1984 TO 1993	23.11	0.004145	421.92	0.83	23.77	0.003975	330.19	0.85	0.00	0.000000	0.00	0.00
1985 TO 1994	1985 TO 1994	23.34	0.003906	417.70	0.87	23.97	0.003694	319.14	0.91	0.00	0.000000	0.00	0.00
1986 TO 1995	1986 TO 1995	24.05	0.003722	409.50	0.97	24.67	0.003453	305.98	1.06	0.00	0.000000	0.00	0.00
1987 TO 1996	1987 TO 1996	28.57	0.002427	309.75	2.14	29.66	0.002316	254.55	2.43	0.00	0.000000	0.00	0.00
1988 TO 1997	1988 TO 1997	29.10	0.002288	307.61	2.17	30.33	0.002079	242.32	2.59	0.00	0.000000	0.00	0.00
1989 TO 1998	1989 TO 1998	29.29	0.002402	305.53	2.21	30.53	0.002097	234.22	2.72	0.00	0.000000	0.00	0.00
1990 TO 1999	1990 TO 1999	29.11	0.002616	310.86	2.13	29.82	0.002219	229.75	2.55	30.15	0.002188	223.87	2.50
1991 TO 2000	1991 TO 2000	27.12	0.003753	296.80	2.31	28.56	0.002934	211.80	2.84	29.01	0.002812	205.07	2.80
1992 TO 2001	1992 TO 2001	34.06	0.002936	336.18	1.79	32.50	0.002902	253.84	2.20	32.85	0.002840	211.57	2.28
1993 TO 2002	1993 TO 2002	28.81	0.003698	328.00	1.89	28.63	0.003716	295.14	2.02	28.58	0.003726	257.13	2.02
1994 TO 2003	1994 TO 2003	28.11	0.002986	329.12	1.87	28.03	0.003004	312.19	1.93	27.93	0.003004	266.72	1.95
1995 TO 2004	1995 TO 2004	27.15	0.002931	322.26	1.98	27.12	0.002950	304.17	2.04	27.10	0.002967	289.71	2.04
1996 TO 2005	1996 TO 2005	24.66	0.004012	310.23	2.12	24.83	0.004024	279.88	2.25	0.00	0.000000	0.00	0.00
1997 TO 2006	1997 TO 2006	24.42	0.003608	309.19	2.13	24.61	0.003613	278.38	2.26	0.00	0.000000	0.00	0.00
1998 TO 2007	1998 TO 2007	23.73	0.003406	305.53	2.17	24.02	0.003386	268.48	2.32	0.00	0.000000	0.00	0.00

ORANGE AND ROCKLAND UTILITIES INC. MORTALITY STUDY BY LEAST SQUARE FITTING OF WEIGHTED RETIREMENT RATIOS
ACCOUNT 3395000 LABORATORY EQUIPMENT PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2007
SUMMARY OF SHRINKING BANDS

YEAR	YEAR	AVERAGE SERVICE LIFE (YEARS)	FIRST DEGREE			SECOND DEGREE			THIRD DEGREE			
			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)
2007 TO 2007	2007 TO 2007	24.28	0.006618	298.63	2.31	25.25	0.006529	231.71	2.82	0.000000	0.00	0.00
2006 TO 2007	2006 TO 2007	26.09	0.005594	304.66	2.19	26.43	0.005583	247.78	2.57	0.000000	0.00	0.00
2005 TO 2007	2005 TO 2007	22.40	0.005961	292.47	2.37	23.54	0.005836	235.76	2.79	0.000000	0.00	0.00
2004 TO 2007	2004 TO 2007	22.90	0.005085	294.70	2.34	23.83	0.005006	241.26	2.71	0.000000	0.00	0.00
2003 TO 2007	2003 TO 2007	22.94	0.004485	298.65	2.29	23.50	0.004470	257.46	2.53	0.000000	0.00	0.00
2002 TO 2007	2002 TO 2007	21.64	0.004221	298.12	2.28	21.98	0.004234	270.71	2.39	0.000000	0.00	0.00
2001 TO 2007	2001 TO 2007	22.06	0.003758	305.94	2.16	22.21	0.003782	290.46	2.23	0.000000	0.00	0.00
2000 TO 2007	2000 TO 2007	22.43	0.003892	300.87	2.27	22.99	0.003831	258.80	2.47	0.000000	0.00	0.00
1999 TO 2007	1999 TO 2007	22.99	0.003653	306.71	2.18	23.33	0.003624	267.86	2.33	0.000000	0.00	0.00
1998 TO 2007	1998 TO 2007	23.73	0.003406	305.53	2.17	24.02	0.003386	268.48	2.32	0.000000	0.00	0.00
1997 TO 2007	1997 TO 2007	24.42	0.003213	309.19	2.15	24.67	0.003200	269.58	2.31	0.000000	0.00	0.00
1996 TO 2007	1996 TO 2007	24.93	0.003125	310.83	2.14	25.15	0.003118	272.42	2.30	0.000000	0.00	0.00
1995 TO 2007	1995 TO 2007	25.44	0.003020	312.56	2.12	25.62	0.003014	271.29	2.30	0.000000	0.00	0.00
1994 TO 2007	1994 TO 2007	25.75	0.002873	312.62	2.09	25.89	0.002869	276.14	2.27	0.000000	0.00	0.00
1993 TO 2007	1993 TO 2007	25.68	0.002911	313.51	2.10	25.82	0.002913	276.93	2.27	0.000000	0.00	0.00
1992 TO 2007	1992 TO 2007	25.56	0.002798	314.99	2.09	25.72	0.002790	274.13	2.27	0.000000	0.00	0.00
1991 TO 2007	1991 TO 2007	24.13	0.003024	304.56	2.23	24.89	0.002779	243.06	2.52	0.000000	239.26	2.45
1990 TO 2007	1990 TO 2007	24.58	0.002754	307.21	2.20	25.21	0.002609	255.87	2.45	0.000000	0.00	0.00
1989 TO 2007	1989 TO 2007	24.93	0.002608	306.85	2.18	25.43	0.002526	261.51	2.38	0.000000	0.00	0.00
1988 TO 2007	1988 TO 2007	25.29	0.002522	310.41	2.15	25.70	0.002477	270.46	2.32	0.000000	0.00	0.00
1987 TO 2007	1987 TO 2007	25.59	0.002443	310.69	2.13	25.92	0.002421	275.81	2.28	0.000000	0.00	0.00
1986 TO 2007	1986 TO 2007	24.87	0.002580	335.80	1.80	24.87	0.002510	287.46	1.85	0.000000	0.00	0.00
1985 TO 2007	1985 TO 2007	25.14	0.002538	336.12	1.79	25.14	0.002485	292.34	1.84	0.000000	0.00	0.00
1984 TO 2007	1984 TO 2007	25.39	0.002509	336.80	1.78	25.38	0.002468	293.49	1.83	0.000000	0.00	0.00
1983 TO 2007	1983 TO 2007	25.61	0.002484	337.79	1.77	25.60	0.002452	298.80	1.82	0.000000	0.00	0.00
1982 TO 2007	1982 TO 2007	25.81	0.002459	339.06	1.76	25.79	0.002433	300.45	1.81	0.000000	0.00	0.00
1981 TO 2007	1981 TO 2007	25.97	0.002426	340.82	1.75	25.95	0.002405	302.54	1.80	0.000000	0.00	0.00
1980 TO 2007	1980 TO 2007	26.13	0.002405	338.68	1.74	26.11	0.002388	304.51	1.79	0.000000	0.00	0.00
1979 TO 2007	1979 TO 2007	26.28	0.002373	340.56	1.73	26.25	0.002359	306.63	1.78	0.000000	0.00	0.00
1978 TO 2007	1978 TO 2007	26.42	0.002350	338.81	1.73	26.39	0.002340	308.88	1.78	0.000000	0.00	0.00
1977 TO 2007	1977 TO 2007	26.54	0.002329	340.99	1.72	26.51	0.002321	311.23	1.77	0.000000	0.00	0.00
1976 TO 2007	1976 TO 2007	26.64	0.002303	339.74	1.72	26.60	0.002298	310.11	1.76	0.000000	0.00	0.00
1975 TO 2007	1975 TO 2007	26.74	0.002282	342.18	1.72	26.71	0.002278	312.67	1.76	0.000000	0.00	0.00
1974 TO 2007	1974 TO 2007	26.79	0.002260	341.48	1.71	26.76	0.002258	312.03	1.75	0.000000	0.00	0.00
1973 TO 2007	1973 TO 2007	26.88	0.002250	340.44	1.71	26.84	0.002249	314.81	1.75	0.000000	0.00	0.00
1972 TO 2007	1972 TO 2007	26.95	0.002239	343.21	1.70	26.92	0.002231	316.84	1.75	0.000000	0.00	0.00
1971 TO 2007	1971 TO 2007	27.02	0.002230	342.33	1.70	27.04	0.002220	316.18	1.74	0.000000	0.00	0.00
1970 TO 2007	1970 TO 2007	27.08	0.002218	341.62	1.70	27.12	0.002207	319.58	1.73	0.000000	0.00	0.00
1969 TO 2007	1969 TO 2007	27.10	0.002204	344.99	1.69	27.17	0.002197	318.99	1.73	0.000000	0.00	0.00
1968 TO 2007	1968 TO 2007	27.15	0.002194	344.35	1.69	27.14	0.002183	318.72	1.74	0.000000	0.00	0.00
1967 TO 2007	1967 TO 2007	27.18	0.002181	344.06	1.69	27.19	0.002171	318.19	1.73	0.000000	0.00	0.00
1966 TO 2007	1966 TO 2007	27.22	0.002169	343.48	1.69	27.22	0.002162	317.84	1.73	0.000000	0.00	0.00
1965 TO 2007	1965 TO 2007	27.25	0.002159	343.10	1.69	27.24	0.002156	317.53	1.73	0.000000	0.00	0.00
1964 TO 2007	1964 TO 2007	27.28	0.002153	342.76	1.69	27.24	0.002152	317.86	1.72	0.000000	0.00	0.00
1963 TO 2007	1963 TO 2007	27.25	0.002149	343.08	1.68	27.21	0.002146	321.44	1.72	0.000000	0.00	0.00
1962 TO 2007	1962 TO 2007	27.26	0.002143	342.99	1.68	27.22	0.002142	321.25	1.72	0.000000	0.00	0.00
1961 TO 2007	1961 TO 2007	27.28	0.002139	346.45	1.67	27.24	0.002141	317.92	1.72	0.000000	0.00	0.00
1960 TO 2007	1960 TO 2007	27.25	0.002138	343.18	1.68	27.21	0.002136	321.27	1.72	0.000000	0.00	0.00
1959 TO 2007	1959 TO 2007	27.27	0.002133	342.82	1.68	27.24	0.002130	321.04	1.72	0.000000	0.00	0.00
1958 TO 2007	1958 TO 2007	27.29	0.002126	346.24	1.68	27.25	0.002127	320.78	1.71	0.000000	0.00	0.00
1957 TO 2007	1957 TO 2007	27.32	0.002124	345.95	1.67	27.30	0.002124	320.51	1.71	0.000000	0.00	0.00
1956 TO 2007	1956 TO 2007	27.34	0.002120	345.65	1.67	27.32	0.002120	320.33	1.71	0.000000	0.00	0.00
1955 TO 2007	1955 TO 2007	27.36	0.002116	345.45	1.67	27.32	0.002116	320.51	1.71	0.000000	0.00	0.00

ORANGE AND ROCKLAND UTILITIES INC. MORTALITY STUDY BY LEAST SQUARE FITTING OF WEIGHTED RETIREMENT RATIOS
ACCOUNT 3395000 LABORATORY EQUIPMENT PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2007

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
1954 TO 2007		27.38	0.002112	345.20	1.67	27.34	0.002115	320.10	1.71	0.00	0.000000	0.00	0.00
1953 TO 2007		27.40	0.002109	344.94	1.67	27.36	0.002112	319.87	1.71	0.00	0.000000	0.00	0.00
1952 TO 2007		27.41	0.002105	344.71	1.67	27.37	0.002108	319.67	1.71	0.00	0.000000	0.00	0.00

ORANGE AND ROCKLAND UTILITIES INC. MORTALITY STUDY BY LEAST SQUARE FITTING OF WEIGHTED RETIREMENT RATIOS
ACCOUNT 3396000 POWER OPERATED EQUIPMENT PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2007

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		16.53	0.021183	390.30	1.14	0.00	0.000000	0.00	0.00	13.14	0.020402	361.53	0.26
1976 TO 1985		23.61	0.009175	328.26	1.87	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1977 TO 1986		24.42	0.007986	329.60	1.87	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1978 TO 1987		18.36	0.011113	313.11	2.10	18.42	0.011282	306.66	2.12	0.00	0.000000	0.00	0.00
1979 TO 1988		17.55	0.010805	304.77	2.16	18.85	0.010910	252.00	2.51	0.00	0.000000	0.00	0.00
1980 TO 1989		17.25	0.010547	298.47	2.24	18.74	0.010610	242.78	2.64	0.00	0.000000	0.00	0.00
1981 TO 1990		16.10	0.010429	301.27	2.24	16.56	0.010590	274.76	2.35	0.00	0.000000	0.00	0.00
1982 TO 1991		16.95	0.010120	297.98	2.29	17.77	0.010236	256.03	2.55	0.00	0.000000	0.00	0.00
1983 TO 1992		16.04	0.009812	289.88	2.36	16.58	0.009952	262.38	2.54	0.00	0.000000	0.00	0.00
1984 TO 1993		17.02	0.007567	296.80	2.37	17.49	0.007625	248.71	2.60	0.00	0.000000	0.00	0.00
1985 TO 1994		17.74	0.007378	290.32	2.51	16.13	0.007270	234.05	2.85	0.00	0.000000	0.00	0.00
1986 TO 1995		15.79	0.008741	281.74	2.51	16.65	0.008650	232.42	2.89	0.00	0.000000	0.00	0.00
1987 TO 1996		16.49	0.008812	281.97	2.55	17.46	0.008253	213.15	3.27	0.00	0.000000	0.00	0.00
1988 TO 1997		18.12	0.005522	289.80	2.41	19.09	0.005112	214.75	3.16	0.00	0.000000	0.00	0.00
1989 TO 1998		20.08	0.004599	296.35	2.30	20.55	0.004589	233.07	2.84	0.00	0.000000	0.00	0.00
1990 TO 1999		21.52	0.004381	313.60	2.07	19.32	0.004427	260.36	2.41	0.00	0.000000	0.00	0.00
1991 TO 2000		20.16	0.005297	300.04	2.28	20.85	0.005336	240.74	2.72	0.00	0.000000	0.00	0.00
1992 TO 2001		21.64	0.005140	311.91	2.13	20.85	0.005207	261.39	2.40	0.00	0.000000	0.00	0.00
1993 TO 2002		24.69	0.004385	330.05	1.88	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1994 TO 2003		18.63	0.012532	260.35	2.92	17.60	0.012046	196.04	2.84	0.00	0.000000	0.00	0.00
1995 TO 2004		18.21	0.013060	255.35	2.99	17.61	0.012633	195.89	3.02	0.00	0.000000	0.00	0.00
1996 TO 2005		18.66	0.013038	259.86	2.97	18.62	0.012682	190.61	3.60	0.00	0.000000	0.00	0.00
1997 TO 2006		17.01	0.014180	255.79	2.99	17.63	0.013815	195.65	3.74	0.00	0.000000	0.00	0.00
1998 TO 2007		16.44	0.014578	258.57	2.95	17.45	0.013939	197.70	3.80	0.00	0.000000	0.00	0.00

ORANGE AND ROCKLAND UTILITIES INC. MORTALITY STUDY BY LEAST SQUARE FITTING OF WEIGHTED RETIREMENT RATIOS
ACCOUNT 3396000 POWER OPERATED EQUIPMENT PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2007
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
2007	TO 2007	12.14	0.032678	284.27	2.58	14.90	0.032372	224.89	3.36	0.00	0.000000	0.00	0.00
2006	TO 2007	10.83	0.027603	318.49	2.45	10.98	0.027998	314.10	2.47	0.00	0.000000	0.00	0.00
2005	TO 2007	12.08	0.027440	285.64	2.37	12.50	0.027808	275.97	2.45	0.00	0.000000	0.00	0.00
2004	TO 2007	13.03	0.023090	280.08	2.48	13.85	0.023297	249.02	2.70	0.00	0.000000	0.00	0.00
2003	TO 2007	13.04	0.021892	264.55	2.84	14.75	0.021418	233.90	3.46	0.00	0.000000	0.00	0.00
2002	TO 2007	14.38	0.019746	260.81	2.88	16.09	0.019223	214.47	3.73	0.00	0.000000	0.00	0.00
2001	TO 2007	15.42	0.017770	256.24	2.95	17.01	0.017158	202.87	3.97	0.00	0.000000	0.00	0.00
2000	TO 2007	15.58	0.016316	253.49	2.97	16.84	0.015877	204.85	3.80	0.00	0.000000	0.00	0.00
1999	TO 2007	15.94	0.015278	260.34	2.91	17.06	0.014721	202.20	3.70	0.00	0.000000	0.00	0.00
1998	TO 2007	16.44	0.014578	258.57	2.95	17.45	0.013939	197.70	3.80	0.00	0.000000	0.00	0.00
1997	TO 2007	16.52	0.013888	257.22	2.95	17.41	0.013209	198.12	3.73	0.00	0.000000	0.00	0.00
1996	TO 2007	16.79	0.013231	259.16	2.96	17.59	0.012485	196.09	3.77	0.00	0.000000	0.00	0.00
1995	TO 2007	16.49	0.012709	257.77	2.91	17.24	0.012063	200.08	3.63	0.00	0.000000	0.00	0.00
1994	TO 2007	16.64	0.012350	261.34	2.91	17.37	0.011697	198.57	3.68	0.00	0.000000	0.00	0.00
1993	TO 2007	16.65	0.011856	261.24	2.88	17.35	0.011207	198.87	3.64	0.00	0.000000	0.00	0.00
1992	TO 2007	16.53	0.011411	263.20	2.84	17.22	0.010779	200.30	3.59	0.00	0.000000	0.00	0.00
1991	TO 2007	16.57	0.011162	262.54	2.82	17.27	0.010543	199.74	3.61	0.00	0.000000	0.00	0.00
1990	TO 2007	16.46	0.010899	270.36	2.77	17.16	0.010344	201.02	3.55	0.00	0.000000	0.00	0.00
1989	TO 2007	16.45	0.010682	270.48	2.75	17.18	0.010096	200.82	3.56	0.00	0.000000	0.00	0.00
1988	TO 2007	16.41	0.010602	271.21	2.73	17.17	0.009932	200.92	3.52	0.00	0.000000	0.00	0.00
1987	TO 2007	16.22	0.010843	268.12	2.73	17.08	0.010075	201.93	3.53	0.00	0.000000	0.00	0.00
1986	TO 2007	16.28	0.010738	273.37	2.70	17.11	0.010188	207.54	3.45	0.00	0.000000	0.00	0.00
1985	TO 2007	16.33	0.010437	272.46	2.68	17.09	0.010013	207.72	3.35	0.00	0.000000	0.00	0.00
1984	TO 2007	16.38	0.010319	271.75	2.65	17.09	0.009983	213.58	3.27	0.00	0.000000	0.00	0.00
1983	TO 2007	16.33	0.010451	272.53	2.65	17.05	0.010150	214.09	3.25	0.00	0.000000	0.00	0.00
1982	TO 2007	16.35	0.010394	278.26	2.63	17.05	0.010135	214.05	3.20	0.00	0.000000	0.00	0.00
1981	TO 2007	16.35	0.010197	278.36	2.62	17.04	0.009953	220.08	3.17	0.00	0.000000	0.00	0.00
1980	TO 2007	16.40	0.010126	277.37	2.61	17.08	0.009908	219.60	3.14	0.00	0.000000	0.00	0.00
1979	TO 2007	16.46	0.010049	276.44	2.60	17.11	0.009848	219.12	3.13	0.00	0.000000	0.00	0.00
1978	TO 2007	16.51	0.010013	275.61	2.59	17.15	0.009823	218.65	3.12	0.00	0.000000	0.00	0.00
1977	TO 2007	16.53	0.009907	275.22	2.59	17.16	0.009725	218.55	3.10	0.00	0.000000	0.00	0.00
1976	TO 2007	16.57	0.009889	280.60	2.58	17.19	0.009710	218.12	3.10	0.00	0.000000	0.00	0.00
1975	TO 2007	16.43	0.009659	276.85	2.56	16.98	0.009522	226.72	3.00	0.00	0.000000	0.00	0.00

ORANGE AND ROCKLAND UTILITIES INC. MORTALITY STUDY BY LEAST SQUARE FITTING OF WEIGHTED RETIREMENT RATIOS
ACCOUNT 3397000 COMMUNICATION EQUIPMENT PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2007
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	18.86	0.006457	416.18	0.88	0.00	0.000000	0.00	0.00	19.34	0.006129	312.80	0.42
1953 TO 1962	1953 TO 1962	20.70	0.006269	422.74	0.83	0.00	0.000000	0.00	0.00	21.48	0.006070	295.61	0.51
1954 TO 1963	1954 TO 1963	18.51	0.006836	451.20	0.57	0.00	0.000000	0.00	0.00	20.05	0.006151	311.66	-0.26
1955 TO 1964	1955 TO 1964	18.01	0.007332	452.63	0.55	0.00	0.000000	0.00	0.00	20.42	0.006465	325.68	-0.90
1956 TO 1965	1956 TO 1965	18.81	0.006960	459.85	0.50	0.00	0.000000	0.00	0.00	21.95	0.006167	321.12	-1.09
1957 TO 1966	1957 TO 1966	19.62	0.006684	461.28	0.51	0.00	0.000000	0.00	0.00	21.29	0.005250	293.63	-0.33
1958 TO 1967	1958 TO 1967	21.69	0.006021	440.31	0.67	0.00	0.000000	0.00	0.00	23.42	0.004718	275.37	0.01
1959 TO 1968	1959 TO 1968	23.41	0.005318	442.14	0.64	0.00	0.000000	0.00	0.00	25.31	0.004044	262.72	0.17
1960 TO 1969	1960 TO 1969	28.15	0.004185	449.37	0.58	0.00	0.000000	0.00	0.00	29.25	0.003160	230.74	0.70
1961 TO 1970	1961 TO 1970	29.59	0.004228	454.49	0.55	0.00	0.000000	0.00	0.00	30.03	0.003315	224.76	0.82
1962 TO 1971	1962 TO 1971	32.09	0.003896	453.37	0.56	0.00	0.000000	0.00	0.00	31.33	0.003066	212.24	1.00
1963 TO 1972	1963 TO 1972	30.75	0.004059	414.69	0.92	0.00	0.000000	0.00	0.00	29.17	0.003535	214.24	1.32
1964 TO 1973	1964 TO 1973	35.20	0.003163	376.44	1.32	0.00	0.000000	0.00	0.00	33.21	0.002960	209.25	1.70
1965 TO 1974	1965 TO 1974	36.11	0.002768	355.83	1.56	0.00	0.000000	0.00	0.00	34.51	0.002748	221.65	1.89
1966 TO 1975	1966 TO 1975	36.09	0.003689	428.13	0.78	0.00	0.000000	0.00	0.00	32.85	0.003693	214.61	1.59
1967 TO 1976	1967 TO 1976	34.41	0.003658	399.65	1.06	0.00	0.000000	0.00	0.00	33.61	0.003669	242.46	1.31
1968 TO 1977	1968 TO 1977	36.39	0.003107	386.13	1.19	0.00	0.000000	0.00	0.00	35.90	0.003105	235.35	1.39
1969 TO 1978	1969 TO 1978	38.50	0.002773	377.92	1.28	0.00	0.000000	0.00	0.00	38.66	0.002772	234.08	1.43
1970 TO 1979	1970 TO 1979	33.23	0.002927	356.62	1.52	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1971 TO 1980	1971 TO 1980	35.24	0.002264	353.33	1.59	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1972 TO 1981	1972 TO 1981	36.52	0.002111	349.09	1.63	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1973 TO 1982	1973 TO 1982	40.53	0.001763	351.63	1.60	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1974 TO 1983	1974 TO 1983	42.67	0.001553	350.40	1.61	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1975 TO 1984	1975 TO 1984	48.33	0.001385	356.94	1.55	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1976 TO 1985	1976 TO 1985	52.04	0.001103	342.98	1.72	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1977 TO 1986	1977 TO 1986	38.17	0.001863	341.89	1.73	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1978 TO 1987	1978 TO 1987	40.53	0.001829	341.73	1.71	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1979 TO 1988	1979 TO 1988	29.61	0.004198	329.34	1.87	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1980 TO 1989	1980 TO 1989	30.62	0.003640	331.45	1.84	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1981 TO 1990	1981 TO 1990	21.00	0.009519	340.44	1.70	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1982 TO 1991	1982 TO 1991	21.46	0.009313	347.13	1.63	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1983 TO 1992	1983 TO 1992	20.92	0.009087	356.16	1.50	0.00	0.000000	0.00	0.00	33.50	0.008814	628.39	-2.60
1984 TO 1993	1984 TO 1993	21.07	0.008373	382.06	1.25	0.00	0.000000	0.00	0.00	27.79	0.008140	440.74	-2.60
1985 TO 1994	1985 TO 1994	21.51	0.007860	388.24	1.18	0.00	0.000000	0.00	0.00	26.76	0.007591	379.25	-2.60
1986 TO 1995	1986 TO 1995	22.30	0.007442	387.93	1.18	0.00	0.000000	0.00	0.00	27.45	0.007180	355.13	-1.74
1987 TO 1996	1987 TO 1996	24.57	0.007078	384.56	1.21	0.00	0.000000	0.00	0.00	31.89	0.006859	318.30	-1.43
1988 TO 1997	1988 TO 1997	25.77	0.006691	386.09	1.18	0.00	0.000000	0.00	0.00	33.60	0.006476	296.09	-0.97
1989 TO 1998	1989 TO 1998	25.51	0.006594	421.35	0.85	0.00	0.000000	0.00	0.00	32.04	0.006298	273.07	-0.45
1990 TO 1999	1990 TO 1999	23.41	0.006179	471.93	0.42	0.00	0.000000	0.00	0.00	28.73	0.005841	290.62	-0.71
1991 TO 2000	1991 TO 2000	36.26	0.003162	550.14	-0.23	0.00	0.000000	0.00	0.00	39.33	0.003058	225.01	0.66
1992 TO 2001	1992 TO 2001	16.12	0.007473	425.04	0.79	0.00	0.000000	0.00	0.00	16.66	0.007280	447.12	0.87
1993 TO 2002	1993 TO 2002	15.54	0.007124	421.55	0.84	0.00	0.000000	0.00	0.00	15.89	0.007016	456.17	0.99
1994 TO 2003	1994 TO 2003	15.31	0.007050	408.14	0.97	0.00	0.000000	0.00	0.00	15.49	0.006869	461.71	1.11
1995 TO 2004	1995 TO 2004	15.63	0.006652	399.85	1.05	0.00	0.000000	0.00	0.00	15.63	0.006473	451.02	1.10
1996 TO 2005	1996 TO 2005	14.41	0.006555	378.20	1.25	0.00	0.000000	0.00	0.00	14.19	0.006286	454.62	1.42
1997 TO 2006	1997 TO 2006	14.63	0.006523	365.69	1.38	0.00	0.000000	0.00	0.00	14.25	0.006285	445.53	1.47
1998 TO 2007	1998 TO 2007	13.25	0.007455	366.08	1.37	0.00	0.000000	0.00	0.00	12.72	0.006959	475.48	1.56

ORANGE AND ROCKLAND UTILITIES INC. MORTALITY STUDY BY LEAST SQUARE FITTING OF WEIGHTED RETIREMENT RATIOS
ACCOUNT 3397000 COMMUNICATION EQUIPMENT PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2007
SUMMARY OF SHRINKING BANDS

		FIRST DEGREE				SECOND DEGREE				THIRD DEGREE			
YEAR	YEAR	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
2007	TO 2007	10.50	0.020335	328.64	1.75	0.00	0.000000	0.00	0.00	9.40	0.018731	1005.38	2.14
2006	TO 2007	14.14	0.014209	335.93	1.71	0.00	0.000000	0.00	0.00	13.38	0.013643	743.60	-1.41
2005	TO 2007	12.96	0.014533	312.57	2.04	0.00	0.000000	0.00	0.00	11.91	0.014343	424.13	2.07
2004	TO 2007	14.41	0.010340	322.60	1.90	0.00	0.000000	0.00	0.00	13.28	0.010134	628.98	1.73
2003	TO 2007	14.69	0.008785	330.24	1.82	0.00	0.000000	0.00	0.00	13.58	0.008529	615.10	1.61
2002	TO 2007	14.55	0.008214	333.24	1.75	0.00	0.000000	0.00	0.00	13.71	0.008086	470.35	1.65
2001	TO 2007	12.04	0.009400	327.95	1.80	0.00	0.000000	0.00	0.00	11.35	0.009090	383.43	1.92
2000	TO 2007	12.91	0.008511	336.93	1.67	0.00	0.000000	0.00	0.00	12.24	0.008190	412.67	1.80
1999	TO 2007	13.05	0.008143	356.20	1.47	0.00	0.000000	0.00	0.00	12.49	0.007781	444.38	1.65
1998	TO 2007	13.25	0.007455	366.08	1.37	0.00	0.000000	0.00	0.00	12.72	0.006959	475.48	1.56
1997	TO 2007	13.90	0.007167	370.54	1.35	0.00	0.000000	0.00	0.00	13.41	0.006732	480.92	1.49
1996	TO 2007	14.46	0.006690	370.01	1.34	0.00	0.000000	0.00	0.00	13.99	0.006276	482.53	1.44
1995	TO 2007	14.95	0.006434	371.16	1.35	0.00	0.000000	0.00	0.00	14.49	0.006054	486.43	1.40
1994	TO 2007	15.31	0.006230	368.93	1.33	0.00	0.000000	0.00	0.00	15.14	0.005852	481.03	1.34
1993	TO 2007	15.55	0.006000	376.15	1.29	0.00	0.000000	0.00	0.00	15.28	0.005645	485.44	1.27
1992	TO 2007	15.71	0.005792	372.26	1.29	0.00	0.000000	0.00	0.00	15.55	0.005402	487.54	1.22
1991	TO 2007	15.99	0.005418	372.18	1.29	0.00	0.000000	0.00	0.00	15.86	0.005012	485.49	1.19
1990	TO 2007	15.50	0.005775	377.52	1.29	0.00	0.000000	0.00	0.00	14.99	0.005208	503.55	1.19
1989	TO 2007	15.73	0.005635	371.98	1.31	0.00	0.000000	0.00	0.00	15.25	0.005104	501.48	1.18
1988	TO 2007	15.76	0.005449	371.22	1.32	0.00	0.000000	0.00	0.00	15.58	0.004897	506.51	1.20
1987	TO 2007	15.99	0.005373	372.07	1.32	0.00	0.000000	0.00	0.00	15.86	0.004864	503.99	1.19
1986	TO 2007	16.03	0.005252	371.10	1.32	0.00	0.000000	0.00	0.00	15.64	0.004746	501.80	1.18
1985	TO 2007	16.23	0.005129	372.86	1.32	0.00	0.000000	0.00	0.00	15.86	0.004648	501.18	1.18
1984	TO 2007	16.39	0.005053	369.06	1.33	0.00	0.000000	0.00	0.00	16.06	0.004593	501.23	1.18
1983	TO 2007	16.54	0.004995	371.79	1.34	0.00	0.000000	0.00	0.00	16.23	0.004551	496.08	1.18
1982	TO 2007	16.68	0.004901	368.74	1.35	0.00	0.000000	0.00	0.00	16.38	0.004464	497.70	1.18
1981	TO 2007	16.80	0.004854	366.15	1.36	0.00	0.000000	0.00	0.00	16.50	0.004424	500.10	1.18
1980	TO 2007	16.90	0.004812	369.80	1.37	0.00	0.000000	0.00	0.00	16.60	0.004386	497.03	1.18
1979	TO 2007	16.96	0.004749	368.43	1.38	0.00	0.000000	0.00	0.00	16.65	0.004320	495.58	1.19
1978	TO 2007	17.04	0.004716	366.69	1.39	0.00	0.000000	0.00	0.00	16.72	0.004287	493.48	1.18
1977	TO 2007	17.11	0.004691	365.22	1.39	0.00	0.000000	0.00	0.00	16.77	0.004264	491.82	1.17
1976	TO 2007	17.12	0.004665	364.99	1.39	0.00	0.000000	0.00	0.00	16.77	0.004235	497.90	1.16
1975	TO 2007	17.13	0.004646	364.86	1.38	0.00	0.000000	0.00	0.00	16.79	0.004217	497.30	1.15
1974	TO 2007	17.16	0.004627	364.17	1.38	0.00	0.000000	0.00	0.00	16.83	0.004201	496.26	1.15
1973	TO 2007	17.19	0.004615	369.30	1.38	0.00	0.000000	0.00	0.00	16.86	0.004190	495.24	1.14
1972	TO 2007	17.22	0.004594	368.69	1.39	0.00	0.000000	0.00	0.00	16.89	0.004173	494.39	1.15
1971	TO 2007	17.25	0.004577	368.05	1.39	0.00	0.000000	0.00	0.00	16.92	0.004156	493.48	1.14
1970	TO 2007	17.27	0.004573	367.62	1.39	0.00	0.000000	0.00	0.00	16.94	0.004153	492.83	1.14
1969	TO 2007	17.29	0.004568	367.21	1.39	0.00	0.000000	0.00	0.00	16.96	0.004149	492.20	1.14
1968	TO 2007	17.31	0.004558	366.77	1.39	0.00	0.000000	0.00	0.00	16.99	0.004140	491.53	1.13
1967	TO 2007	17.33	0.004552	366.38	1.39	0.00	0.000000	0.00	0.00	17.01	0.004135	490.93	1.13
1966	TO 2007	17.32	0.004552	366.72	1.38	0.00	0.000000	0.00	0.00	16.99	0.004129	491.36	1.12
1965	TO 2007	17.33	0.004548	366.42	1.38	0.00	0.000000	0.00	0.00	17.01	0.004127	490.89	1.12
1964	TO 2007	17.33	0.004544	366.36	1.38	0.00	0.000000	0.00	0.00	17.01	0.004121	490.77	1.12
1963	TO 2007	17.32	0.004530	366.58	1.38	0.00	0.000000	0.00	0.00	17.01	0.004101	485.09	1.11
1962	TO 2007	17.33	0.004526	366.31	1.38	0.00	0.000000	0.00	0.00	17.02	0.004099	484.69	1.11
1961	TO 2007	17.35	0.004522	366.09	1.38	0.00	0.000000	0.00	0.00	17.03	0.004093	484.15	1.11
1960	TO 2007	17.35	0.004519	365.94	1.38	0.00	0.000000	0.00	0.00	17.03	0.004086	484.43	1.11
1959	TO 2007	17.34	0.004514	366.13	1.38	0.00	0.000000	0.00	0.00	17.04	0.004084	484.25	1.11
1958	TO 2007	17.35	0.004512	366.01	1.38	0.00	0.000000	0.00	0.00	17.04	0.004082	484.24	1.11
1957	TO 2007	17.35	0.004508	366.06	1.38	0.00	0.000000	0.00	0.00	17.01	0.004070	484.89	1.11
1956	TO 2007	17.32	0.004500	366.57	1.37	0.00	0.000000	0.00	0.00	17.01	0.004070	484.89	1.11
1955	TO 2007	17.33	0.004496	366.43	1.38	0.00	0.000000	0.00	0.00	17.02	0.004068	484.67	1.11

ORANGE AND ROCKLAND UTILITIES INC. MORTALITY STUDY BY LEAST SQUARE FITTING OF WEIGHTED RETIREMENT RATIOS
ACCOUNT 3397000 COMMUNICATION EQUIPMENT PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2007

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)
1954 TO 2007		17.34	0.004492	366.31	1.38	0.00	0.000000	0.00	0.00	484.47
1953 TO 2007		17.34	0.004483	366.20	1.38	0.00	0.000000	0.00	0.00	484.30
1952 TO 2007		17.34	0.004480	366.18	1.38	0.00	0.000000	0.00	0.00	484.26
						17.03	0.004063	484.47	1.11	
						17.03	0.004055	484.30	1.11	
						17.04	0.004053	484.26	1.11	

ORANGE AND ROCKLAND UTILITIES INC. MORTALITY STUDY BY LEAST SQUARE FITTING OF WEIGHTED RETIREMENT RATIOS
ACCOUNT 3398000 MISCELLANEOUS EQUIPMENT PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2007

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
1953 TO 1962		34.85	0.002936	431.88	0.76	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1954 TO 1963		37.61	0.002805	469.24	0.43	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1955 TO 1964		34.58	0.003386	446.78	0.62	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1956 TO 1965		35.07	0.003354	420.59	0.85	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1957 TO 1966		35.49	0.004087	480.41	0.34	0.00	0.000000	0.00	0.00	36.44	0.004022	297.77	0.20
1958 TO 1967		33.58	0.004108	451.13	0.58	0.00	0.000000	0.00	0.00	32.93	0.004042	302.12	0.56
1959 TO 1968		33.53	0.004346	457.80	0.53	0.00	0.000000	0.00	0.00	31.20	0.004224	280.48	0.65
1960 TO 1969		33.20	0.004361	459.30	0.52	0.00	0.000000	0.00	0.00	30.61	0.004250	285.90	0.52
1961 TO 1970		38.59	0.003832	454.82	0.56	0.00	0.000000	0.00	0.00	33.42	0.003682	237.89	0.92
1962 TO 1971		47.74	0.002716	476.53	0.37	0.00	0.000000	0.00	0.00	37.63	0.002422	203.31	1.26
1963 TO 1972		51.49	0.002504	449.56	0.61	0.00	0.000000	0.00	0.00	41.02	0.002332	198.68	1.47
1964 TO 1973		53.25	0.002436	423.47	0.84	0.00	0.000000	0.00	0.00	43.44	0.002285	196.84	1.57
1965 TO 1974		60.77	0.002361	440.21	0.69	0.00	0.000000	0.00	0.00	46.46	0.002210	186.19	1.75
1966 TO 1975		63.67	0.002137	451.55	0.59	0.00	0.000000	0.00	0.00	47.72	0.001958	181.28	1.81
1967 TO 1976		63.03	0.001674	414.89	0.92	0.00	0.000000	0.00	0.00	54.84	0.001609	197.85	1.69
1968 TO 1977		80.35	0.001328	437.44	0.72	0.00	0.000000	0.00	0.00	60.61	0.001265	180.67	2.11
1969 TO 1978		45.14	0.001780	382.14	1.26	0.00	0.000000	0.00	0.00	45.49	0.001795	286.90	1.24
1970 TO 1979		47.44	0.001647	369.92	1.39	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1971 TO 1980		50.01	0.001542	368.92	1.40	0.00	0.000000	0.00	0.00	58.35	0.001532	359.06	0.51
1972 TO 1981		50.78	0.001517	375.14	1.33	0.00	0.000000	0.00	0.00	31.84	0.003754	381.55	0.64
1973 TO 1982		30.78	0.003788	375.20	1.30	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1974 TO 1983		22.28	0.004554	356.84	1.52	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1975 TO 1984		22.90	0.004367	347.23	1.61	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1976 TO 1985		23.76	0.004032	343.01	1.69	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1977 TO 1986		22.05	0.004496	337.82	1.77	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1978 TO 1987		22.65	0.003992	333.31	1.79	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1979 TO 1988		21.95	0.004629	325.71	1.88	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1980 TO 1989		22.24	0.004121	325.99	1.89	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1981 TO 1990		22.74	0.003696	327.55	1.91	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1982 TO 1991		23.39	0.003633	331.28	1.86	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1983 TO 1992		19.76	0.005033	311.19	2.07	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1984 TO 1993		22.25	0.004048	321.37	1.99	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1985 TO 1994		20.96	0.004898	315.18	2.03	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1986 TO 1995		21.73	0.004442	317.73	2.02	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1987 TO 1996		23.45	0.004390	320.08	2.01	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1988 TO 1997		24.53	0.004115	324.21	1.92	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1989 TO 1998		27.30	0.004136	332.72	1.84	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1990 TO 1999		28.70	0.004000	343.14	1.70	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1991 TO 2000		29.58	0.003794	352.58	1.58	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1992 TO 2001		29.64	0.003794	352.58	1.58	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1993 TO 2002		44.67	0.002113	413.07	0.93	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1994 TO 2003		27.42	0.002699	370.11	1.37	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1995 TO 2004		27.83	0.003196	364.67	1.41	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1996 TO 2005		24.03	0.004848	330.90	1.84	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1997 TO 2006		22.50	0.004976	335.59	1.77	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1998 TO 2007		21.99	0.004719	352.49	1.58	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
ACCOUNT 3398000 MISCELLANEOUS EQUIPMENT PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2007

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
2007 TO 2007	2007 TO 2007	29.68	0.004394	432.89	0.75	0.00	0.000000	0.00	0.00	43.69	0.004398	310.16	-1.99
2006 TO 2007	2006 TO 2007	20.84	0.005899	371.81	1.33	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
2005 TO 2007	2005 TO 2007	18.83	0.007533	326.58	1.90	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
2004 TO 2007	2004 TO 2007	19.68	0.007532	327.74	1.86	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
2003 TO 2007	2003 TO 2007	17.65	0.007598	342.74	1.65	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
2002 TO 2007	2002 TO 2007	18.78	0.006472	348.83	1.63	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
2001 TO 2007	2001 TO 2007	19.39	0.006001	353.36	1.52	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
2000 TO 2007	2000 TO 2007	20.21	0.005471	358.75	1.50	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1999 TO 2007	1999 TO 2007	21.03	0.004975	359.05	1.51	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1998 TO 2007	1998 TO 2007	21.99	0.004719	352.49	1.58	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1997 TO 2007	1997 TO 2007	22.79	0.004485	344.44	1.65	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1996 TO 2007	1996 TO 2007	23.38	0.004275	340.00	1.72	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1995 TO 2007	1995 TO 2007	23.92	0.004167	336.47	1.76	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1994 TO 2007	1994 TO 2007	23.52	0.004113	338.06	1.77	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1993 TO 2007	1993 TO 2007	23.83	0.003955	337.85	1.77	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1992 TO 2007	1992 TO 2007	22.57	0.004135	334.48	1.82	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1991 TO 2007	1991 TO 2007	22.78	0.004045	335.82	1.79	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1990 TO 2007	1990 TO 2007	23.01	0.003958	332.45	1.80	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1989 TO 2007	1989 TO 2007	23.16	0.003876	334.67	1.80	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1988 TO 2007	1988 TO 2007	23.06	0.003815	331.81	1.82	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1987 TO 2007	1987 TO 2007	23.22	0.003758	333.74	1.82	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1986 TO 2007	1986 TO 2007	23.09	0.003732	331.25	1.83	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1985 TO 2007	1985 TO 2007	23.24	0.003663	333.54	1.84	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1984 TO 2007	1984 TO 2007	23.33	0.003620	332.14	1.84	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1983 TO 2007	1983 TO 2007	22.93	0.003597	329.21	1.85	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1982 TO 2007	1982 TO 2007	22.72	0.003535	332.24	1.83	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1981 TO 2007	1981 TO 2007	22.82	0.003486	330.90	1.82	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1980 TO 2007	1980 TO 2007	22.92	0.003455	333.76	1.82	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1979 TO 2007	1979 TO 2007	23.01	0.003419	332.47	1.82	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1978 TO 2007	1978 TO 2007	23.00	0.003393	332.60	1.81	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1977 TO 2007	1977 TO 2007	23.08	0.003367	331.46	1.81	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1976 TO 2007	1976 TO 2007	23.14	0.003351	334.90	1.81	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1975 TO 2007	1975 TO 2007	23.19	0.003316	334.16	1.80	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1974 TO 2007	1974 TO 2007	23.24	0.003289	333.52	1.80	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1973 TO 2007	1973 TO 2007	23.28	0.003276	332.88	1.80	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1972 TO 2007	1972 TO 2007	23.32	0.003262	336.60	1.79	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1971 TO 2007	1971 TO 2007	23.36	0.003243	336.04	1.79	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1970 TO 2007	1970 TO 2007	23.39	0.003237	335.56	1.79	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1969 TO 2007	1969 TO 2007	23.41	0.003227	335.32	1.78	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1968 TO 2007	1968 TO 2007	23.43	0.003216	335.09	1.77	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1967 TO 2007	1967 TO 2007	23.44	0.003207	334.89	1.77	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1966 TO 2007	1966 TO 2007	23.45	0.003204	339.02	1.77	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1965 TO 2007	1965 TO 2007	23.47	0.003200	338.74	1.77	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1964 TO 2007	1964 TO 2007	23.48	0.003157	338.63	1.76	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1963 TO 2007	1963 TO 2007	23.49	0.003156	338.47	1.76	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1962 TO 2007	1962 TO 2007	23.49	0.003154	338.38	1.76	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1961 TO 2007	1961 TO 2007	23.50	0.003154	338.32	1.76	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1960 TO 2007	1960 TO 2007	23.50	0.003156	338.27	1.76	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1959 TO 2007	1959 TO 2007	23.52	0.003152	338.04	1.75	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1958 TO 2007	1958 TO 2007	23.53	0.003141	337.86	1.75	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1957 TO 2007	1957 TO 2007	23.54	0.003139	337.67	1.75	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1956 TO 2007	1956 TO 2007	23.55	0.003135	337.60	1.75	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
1955 TO 2007	1955 TO 2007	23.56	0.003128	337.46	1.75	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
ACCOUNT 3398000 MISCELLANEOUS EQUIPMENT PSC CASE 1 ORANGE AND ROCKLAND UTILITIES INC STUDY NO. 2007

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)
1954 TO 2007	2007	23.57	0.003105	337.32	1.75	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
	1953 TO 2007	23.57	0.003102	337.32	1.74	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00

ORANGE AND ROCKLAND UTILITIES, INC.

GAS PLANT

SUMMARY OF HISTORICAL NET SALVAGE

NOVEMBER 2008

ORANGE AND ROCKLAND UTILITIES, INC.
SUMMARY OF HISTORICAL NET SALVAGE

ACCOUNT	305000	STRUCTURES AND IMPROVEMENTS									
		BOOK COST OF PLANT RETIRED	AMOUNT \$	N E T		PERCENTAGE OF BOOK COST RETIRED					
				ONE YEAR BAND %	SHRINKING BAND ENDING				5 YEAR ROLLING BAND %		
					IN 2007		IN 1983				
YEAR				%	%	%	%	%	%	%	
1983		3,572.57	(1,600.00)	(44.79)	(44.66)	(44.79)					
1984		0.00	0.00	0.00	(44.65)	(44.79)					
1985		0.00	0.00	0.00	(44.65)	(44.79)					
1986		0.00	0.00	0.00	(44.65)	(44.79)					
1987		0.00	0.00	0.00	(44.65)	(44.79)				(44.79)	
1988		6,398.62	(6,435.08)	(100.57)	(44.65)	(80.58)				(100.57)	
1989		25.00	0.00	0.00	(42.92)	(80.38)				(100.18)	
1990		1,450.54	(2,705.96)	(186.55)	(42.93)	(93.84)				(116.09)	
1991		19,876.16	(2,368.00)	(11.91)	(41.91)	(41.85)				(41.47)	
1992		23,399.75	(1,064.58)	(4.55)	(45.13)	(25.90)				(24.58)	
1993		158.57	0.00	0.00	(51.01)	(25.83)				(13.67)	
1994		36,368.38	0.00	0.00	(51.06)	(15.53)				(7.55)	
1995		48,217.82	(9,891.86)	(20.51)	(65.91)	(17.26)				(10.41)	
1996		5,284.75	(20,552.23)	(388.90)	(94.39)	(30.82)				(27.78)	
1997		0.00	0.00	0.00	(72.64)	(30.82)				(33.82)	
1998		785.10	(3,046.47)	(388.04)	(72.64)	(32.75)				(36.94)	
1999		0.00	0.00	0.00	(69.14)	(32.75)				(61.69)	
2000		33,147.16	0.00	0.00	(69.14)	(26.68)				(60.17)	
2001		8,573.31	(48,125.30)	(561.34)	(130.04)	(51.15)				(120.39)	
2002		402.18	(810.70)	(201.58)	(2.79)	(51.48)				(121.15)	
2003		21,215.16	0.00	0.00	0.00	(46.25)				(77.26)	
2004		7,442.13	0.00	0.00	0.00	(44.66)				(69.14)	
2005		0.00	0.00	0.00	0.00	(44.66)				0.00	
2006		0.00	0.00	0.00	0.00	(44.66)				0.00	
2007		0.00	0.00	0.00	0.00	(44.66)				0.00	
TOTAL		216,317.20	(96,600.18)								

ORANGE AND ROCKLAND UTILITIES, INC.
SUMMARY OF HISTORICAL NET SALVAGE

ACCOUNT	311002	LP GAS EQUIPMENT	N E T S A L V A G E				
			PERCENTAGE OF BOOK COST RETIRED				
			AMOUNT	ONE YEAR		SHRINKING BAND ENDING	
				BAND	%	IN 2007	IN 1983
YEAR	BOOK COST OF PLANT RETIRED	\$	\$		%	%	%
1983	0.00	131.25	**	(28.86)	**		
1984	0.00	0.00	0.00	(28.88)	**		
1985	0.00	(111.74)	**	(28.88)	**		
1986	0.00	0.00	0.00	(28.86)	**		
1987	0.00	0.00	0.00	(28.86)	**		**
1988	14,753.32	(10,290.97)	(69.75)	(28.86)	(69.62)		(70.51)
1989	1,323.89	(1,341.28)	(101.31)	(27.52)	(72.23)		(73.05)
1990	30,396.09	(13,297.10)	(43.75)	(27.31)	(53.60)		(53.64)
1991	5,219.19	(817.59)	(15.67)	(26.12)	(49.77)		(49.81)
1992	35,888.18	(14,693.85)	(40.94)	(26.25)	(46.15)		(46.18)
1993	1,503.63	(2,634.78)	(175.23)	(24.86)	(48.33)		(44.11)
1994	101,191.42	(29,125.67)	(28.78)	(24.26)	(37.94)		(34.77)
1995	28,231.26	(14,011.54)	(49.63)	(22.60)	(39.45)		(35.62)
1996	492.99	(539.38)	(109.41)	(19.52)	(39.60)		(36.46)
1997	0.00	0.00	0.00	(19.34)	(39.60)		(35.24)
1998	26,978.12	(8,882.49)	(32.92)	(19.34)	(38.87)		(33.50)
1999	31,873.25	(10,636.54)	(33.37)	(17.68)	(38.24)		(38.90)
2000	2,508.37	(318.55)	(12.70)	(15.03)	(38.01)		(32.94)
2001	32,369.62	(17,094.37)	(52.81)	(15.06)	(39.54)		(39.40)
2002	7,046.32	(4,195.31)	(59.54)	(7.11)	(39.98)		(40.81)
2003	146,329.87	0.00	0.00	(4.59)	(27.43)		(14.65)
2004	281.03	(6,722.75)	(2,392.18)	(2,392.18)	(28.86)		(15.03)
2005	1,447.56	0.00	0.00	(388.92)	(28.77)		0.00
2006	8,972.07	(838.63)	(9.35)	(70.66)	(28.40)		0.00
2007	667.96	(9,644.93)	(1,443.94)	(151.35)	(30.38)		0.00
TOTAL	477,474.14	(145,066.22)					

ORANGE AND ROCKLAND UTILITIES, INC.
SUMMARY OF HISTORICAL NET SALVAGE

ACCOUNT		375000	STRUCTURES AND IMPROVEMENTS						
YEAR	BOOK COST OF PLANT RETIRED	AMOUNT \$	N E T S A L V A G E					5 YEAR ROLLING BAND %	
			PERCENTAGE OF BOOK COST RETIRED						
			ONE YEAR BAND	SHRINKING BAND ENDING			IN 1983		
			%	IN 2007		%			
1983	0.00	(100.00)	**	(70.34)	**				
1984	6,164.80	(2,544.15)	(41.27)	(70.27)	(42.89)				
1985	465.06	0.00	0.00	(71.64)	(39.88)				
1986	531.60	(200.00)	(37.62)	(71.89)	(39.71)				
1987	5,896.37	(2,925.19)	(49.61)	(72.03)	(44.18)			(44.18)	
1988	3,195.38	(3,709.22)	(116.08)	(73.10)	(58.32)			(57.70)	
1989	386.42	(100.41)	(25.98)	(71.96)	(57.57)			(66.20)	
1990	1,437.73	(10,696.89)	(744.01)	(72.11)	(112.16)			(154.02)	
1991	6,650.49	(2,864.00)	(43.06)	(63.98)	(93.58)			(115.54)	
1992	74.99	0.00	0.00	(65.22)	(93.30)			(147.90)	
1993	0.00	0.00	0.00	(65.27)	(93.30)			(159.79)	
1994	45,165.01	(2,330.00)	(5.16)	(65.27)	(36.40)			(29.80)	
1995	3,036.49	(3,736.00)	(123.04)	(105.78)	(40.01)			(16.26)	
1996	1,112.51	(3,000.05)	(269.66)	(104.96)	(43.45)			(18.36)	
1997	0.00	0.00	0.00	(102.05)	(43.45)			(18.38)	
1998	52,954.70	(42,775.80)	(80.78)	(102.05)	(59.01)			(50.69)	
1999	8,364.37	(21,269.97)	(254.29)	(215.79)	(71.07)			(108.12)	
2000	0.00	0.00	0.00	(6.50)	(71.07)			(107.39)	
2001	0.00	0.00	0.00	(6.50)	(71.07)			(104.45)	
2002	1,538.82	(100.00)	(6.50)	(6.50)	(70.34)			(102.05)	
2003	0.00	0.00	0.00	**	(70.34)			(215.79)	
2004	0.00	0.00	0.00	**	(70.34)			(6.50)	
2005	0.00	0.00	0.00	**	(70.34)			(6.50)	
2006	5,445.35	(16,610.80)	(305.05)	(305.05)	(79.32)			(239.27)	
2007	0.00	0.00	0.00	0.00	(79.32)			(305.05)	
TOTAL		142,420.09	(112,962.48)						

ORANGE AND ROCKLAND UTILITIES, INC.
SUMMARY OF HISTORICAL NET SALVAGE

ACCOUNT	376000	MAINS	N E T S A L V A G E				
			PERCENTAGE OF BOOK COST RETIRED				
			AMOUNT	ONE YEAR		SHRINKING BAND ENDING	
				BAND	IN 2007	IN 1983	5 YEAR
YEAR	RETIRED		\$ \$	%	%	%	ROLLING BAND
1983	35,228.49		(53,818.39)	(152.77)	(85.15)	(152.77)	(164.87)
1984	19,702.10		(44,201.97)	(224.35)	(84.59)	(178.44)	(133.77)
1985	27,235.41		(22,129.73)	(81.25)	(83.94)	(146.23)	(102.20)
1986	9,469.01		(20,078.09)	(212.04)	(83.96)	(153.03)	(113.01)
1987	10,299.46		(27,833.03)	(270.24)	(83.67)	(164.87)	(119.69)
1988	77,633.73		(78,834.90)	(101.55)	(83.21)	(137.49)	(131.62)
1989	220,431.53		(203,801.21)	(92.46)	(82.86)	(112.67)	(144.38)
1990	304,637.87		(372,915.12)	(122.41)	(82.32)	(116.88)	(157.30)
1991	132,299.03		(208,679.87)	(157.73)	(78.90)	(123.34)	(183.33)
1992	141,934.66		(290,031.86)	(204.34)	(75.87)	(135.09)	(177.46)
1993	161,134.72		(311,222.35)	(193.14)	(70.35)	(143.29)	(127.04)
1994	130,275.54		(186,092.47)	(142.85)	(64.05)	(143.25)	(80.69)
1995	135,486.88		(289,363.16)	(213.57)	(60.64)	(150.02)	(72.77)
1996	125,311.02		(155,090.08)	(123.76)	(53.43)	(147.88)	(51.57)
1997	144,603.25		56,572.76	39.12	(50.22)	(131.74)	(41.63)
1998	345,423.88		(137,021.36)	(39.67)	(55.18)	(116.00)	(45.28)
1999	283,761.90		(227,917.35)	(80.32)	(57.55)	(111.61)	(55.99)
2000	373,825.71		(193,038.92)	(51.64)	(54.28)	(103.24)	(54.28)
2001	424,496.01		(153,136.23)	(36.07)	(54.90)	(94.05)	(62.39)
2002	308,726.47		(74,967.90)	(24.28)	(61.69)	(87.74)	(58.68)
2003	409,107.71		(358,767.57)	(87.70)	(74.99)	(87.73)	(71.39)
2004	459,152.53		(292,373.10)	(63.68)	(63.68)	(85.15)	
2005	284,613.68		(297,449.44)	(104.51)	(79.30)	(86.36)	
2006	585,827.31		(177,900.41)	(30.37)	(57.74)	(79.99)	
2007	377,937.76		(384,637.30)	(101.77)	(67.49)	(81.48)	
TOTAL	5,528,555.66		(4,504,729.05)				

ORANGE AND ROCKLAND UTILITIES, INC.
SUMMARY OF HISTORICAL NET SALVAGE

ACCOUNT		378000	MEASURING AND REGULATING EQUIPMENT						
YEAR	BOOK COST OF PLANT RETIRED	AMOUNT \$	PERCENTAGE OF BOOK COST RETIRED						
			ONE YEAR BAND %	SHRINKING BAND ENDING		5 YEAR ROLLING BAND %			
					IN 2007 %	IN 1983 %			
1983	17,396.13	(4,332.24)	(24.90)	(24.70)	(24.90)				
1984	80,981.35	(24,083.66)	(29.74)	(24.70)	(28.88)				
1985	(465.06)	(7,300.00)	*	(24.50)	(36.48)				
1986	33,464.81	(34,972.27)	(104.50)	(24.14)	(53.81)		(50.47)		
1987	50,693.33	(21,194.80)	(41.81)	(22.81)	(50.47)		(47.57)		
1988	55,801.79	(17,327.23)	(31.05)	(22.32)	(45.91)		(29.09)		
1989	214,367.08	(22,153.35)	(10.33)	(22.06)	(29.05)		(30.86)		
1990	81,636.24	(38,872.20)	(47.62)	(23.54)	(31.89)		(22.50)		
1991	91,102.93	(11,495.21)	(12.62)	(22.33)	(29.08)		(12.98)		
1992	297,436.75	(6,254.27)	(2.10)	(22.91)	(20.38)		(13.04)		
1993	72,186.76	(19,900.09)	(27.57)	(27.96)	(20.90)		(12.74)		
1994	114,000.14	(7,123.75)	(6.25)	(27.98)	(19.39)		(11.74)		
1995	28,405.28	(26,021.35)	(91.61)	(30.37)	(21.20)		(12.77)		
1996	84,251.39	(16,875.34)	(20.03)	(28.65)	(21.12)		(23.27)		
1997	79,000.25	(17,989.53)	(22.77)	(29.43)	(21.22)		(49.10)		
1998	47,961.41	(105,616.39)	(220.21)	(30.05)	(28.30)		(60.18)		
1999	85,013.51	(28,864.63)	(33.95)	(18.64)	(28.63)		(52.52)		
2000	61,139.83	(18,354.07)	(30.02)	(16.81)	(28.69)		(66.89)		
2001	39,754.86	(38,442.57)	(96.70)	(15.58)	(30.45)		(32.94)		
2002	380,294.13	(11,026.39)	(2.90)	(10.31)	(24.98)		(15.79)		
2003	73,896.34	(4,413.14)	(5.97)	(22.44)	(24.27)		(16.81)		
2004	158,697.45	(47,771.73)	(30.10)	(30.10)	(24.70)		(17.01)		
2005	467,808.02	(88,943.48)	(19.01)	(21.82)	(23.69)		(13.46)		
2006	251,790.59	(27,195.05)	(10.80)	(18.66)	(22.55)		(15.08)		
2007	264,843.47	(15,261.02)	(5.76)	(15.67)	(21.13)				
TOTAL	3,131,458.78	(661,783.76)							

ORANGE AND ROCKLAND UTILITIES, INC.
SUMMARY OF HISTORICAL NET SALVAGE

ACCOUNT	380000	SERVICES	N E T	PERCENTAGE OF BOOK COST RETIRED						
				BOOK COST OF PLANT RETIRED	ONE YEAR		SHRINKING BAND ENDING		5 YEAR ROLLING BAND	
					AMOUNT	BAND	IN 2007			IN 1983
							\$	%		
YEAR										
		\$								%
1983	73,844.50	(111,123.37)	(150.48)	(134.95)	(150.48)					
1984	29,383.18	(65,755.38)	(223.79)	(134.52)	(171.35)					
1985	78,437.99	(109,828.80)	(140.02)	(133.53)	(157.82)					
1986	63,018.22	(103,602.47)	(164.40)	(133.33)	(159.52)					
1987	36,242.40	(117,127.84)	(323.18)	(132.55)	(180.63)					(180.63)
1988	147,535.06	(137,313.89)	(93.07)	(129.75)	(150.48)					(150.48)
1989	138,161.59	(83,486.20)	(60.43)	(132.08)	(128.52)					(118.98)
1990	112,090.19	(137,642.41)	(122.80)	(136.62)	(127.58)					(116.52)
1991	102,140.71	(159,410.96)	(156.07)	(137.36)	(131.30)					(118.43)
1992	150,360.56	(137,296.51)	(91.31)	(136.39)	(124.85)					(100.75)
1993	131,520.17	(145,982.63)	(111.00)	(140.12)	(123.13)					(104.66)
1994	124,133.91	(168,064.20)	(135.39)	(142.40)	(124.41)					(120.66)
1995	90,144.74	(163,487.80)	(181.36)	(142.96)	(128.43)					(129.41)
1996	118,541.40	(152,058.24)	(128.27)	(140.60)	(128.42)					(124.76)
1997	156,982.34	(160,578.69)	(102.29)	(141.68)	(125.78)					(127.18)
1998	14,539.51	(164,704.57)	(1,132.81)	(146.85)	(135.12)					(160.39)
1999	618,739.20	(174,600.23)	(28.22)	(134.72)	(104.86)					(81.63)
2000	182,858.01	(192,084.84)	(105.05)	(251.92)	(104.88)					(77.32)
2001	142,842.60	(230,180.80)	(161.14)	(322.73)	(108.08)					(82.63)
2002	50,788.20	(280,072.21)	(551.45)	(420.32)	(116.86)					(103.16)
2003	95,188.01	(348,125.03)	(365.72)	(384.46)	(125.78)					(112.35)
2004	90,515.74	(365,837.50)	(404.17)	(404.17)	(134.95)					(251.92)
2005	165,258.25	(435,551.63)	(263.56)	(313.32)	(142.24)					(304.77)
2006	155,384.78	(541,112.16)	(348.24)	(326.52)	(152.67)					(353.72)
2007	214,383.62	(785,482.96)	(366.39)	(340.18)	(166.63)					(343.56)
TOTAL	3,283,034.88	(5,470,511.32)								

ORANGE AND ROCKLAND UTILITIES, INC.
SUMMARY OF HISTORICAL NET SALVAGE

ACCOUNT		381000	METERS & HOUSE REGULATORS						
YEAR	BOOK COST OF PLANT RETIRED \$\$	AMOUNT \$	N	E	T	PERCENTAGE OF BOOK COST RETIRED			
						ONE YEAR BAND %	SHRINKING BAND ENDING		5 YEAR ROLLING BAND %
							IN 2007 %	IN 1983 %	
1983	24,282.10	29.62				0.12	4.37	0.12	
1984	17,976.81	(8,271.95)				(46.01)	4.43	(19.50)	
1985	50,680.90	1,602.57				3.16	4.96	(7.14)	
1986	50,227.95	(1,217.04)				(2.42)	5.01	(5.49)	
1987	22,274.22	(159.92)				(0.72)	5.24	(4.85)	
1988	50,861.82	(40.12)				(0.08)	5.33	(3.72)	(4.85)
1989	49,548.70	(808.83)				(1.63)	5.51	(3.33)	(4.21)
1990	90,113.53	(14,593.57)				(16.19)	5.75	(6.59)	(0.28)
1991	72,597.18	(697.18)				(0.96)	7.16	(5.64)	(6.39)
1992	73,867.18	(23.32)				(0.03)	7.61	(4.81)	(5.71)
1993	75,334.96	4,038.00				5.36	8.06	(3.49)	(4.80)
1994	161,112.92	26,655.00				16.54	8.24	0.88	(3.34)
1995	116,977.12	13,288.22				11.36	6.91	2.31	3.25
1996	37,127.50	6,900.92				18.59	6.33	2.99	8.65
1997	57,211.03	17,240.44				30.13	5.80	4.62	10.95
1998	201,175.07	6,966.40				3.46	4.06	4.42	15.21
1999	77,288.44	14,000.35				18.11	4.26	5.28	12.39
2000	8,036.00	11,525.35				143.42	2.21	6.18	11.92
2001	11,728.72	0.00				0.00	0.00	6.12	14.87
2002	358,369.87	0.00				0.00	0.00	4.76	13.99
2003	63,554.06	0.00				0.00	0.00	4.58	4.95
2004	80,058.24	0.00				0.00	0.00	4.37	4.92
2005	74,130.40	0.00				0.00	0.00	4.19	2.21
2006	448,638.76	0.00				0.00	0.00	3.36	0.00
2007	133,207.68	0.00				0.00	0.00	3.18	0.00
TOTAL	2,406,381.16	76,434.94							

ORANGE AND ROCKLAND UTILITIES, INC.
SUMMARY OF HISTORICAL NET SALVAGE

ACCOUNT		382000	METER & HOUSE REGULATOR INSTALLATIONS						
YEAR	BOOK COST OF PLANT RETIRED	AMOUNT \$	N E T S A L V A G E					5 YEAR ROLLING BAND %	
			PERCENTAGE OF BOOK COST RETIRED						
			ONE YEAR BAND %	SHRINKING BAND ENDING IN 2007		IN 1983			
1983	25,367.74	(39,769.37)	(156.77)	(160.51)	(156.77)				
1984	47,393.71	(44,114.59)	(93.08)	(160.75)	(115.29)				
1985	50,589.79	(83,665.01)	(165.38)	(169.97)	(135.83)				
1986	36,414.04	(46,015.21)	(126.37)	(170.75)	(133.67)				
1987	14,007.56	(7,983.42)	(56.99)	(176.94)	(127.49)				(127.49)
1988	14,470.03	(13,042.21)	(90.13)	(183.74)	(124.62)				(119.61)
1989	27,144.73	(6,950.27)	(25.60)	(189.56)	(112.14)				(110.54)
1990	11,844.28	(59,056.08)	(498.60)	(211.23)	(132.29)				(128.08)
1991	8,718.03	(35,848.13)	(411.20)	(193.65)	(142.59)				(161.29)
1992	11,186.84	(27,201.89)	(243.16)	(183.39)	(147.14)				(193.69)
1993	14,186.96	(20,340.70)	(143.38)	(179.54)	(146.94)				(204.43)
1994	9,229.12	(22,775.01)	(246.77)	(182.75)	(150.34)				(299.50)
1995	19,008.14	(15,792.11)	(83.08)	(178.82)	(145.93)				(195.67)
1996	5,960.59	(11,750.92)	(197.14)	(192.69)	(146.96)				(164.27)
1997	618.46	(23,724.35)	(3,836.04)	(192.47)	(154.67)				(192.61)
1998	3,030.59	(20,432.92)	(674.22)	(174.40)	(159.93)				(249.62)
1999	10,719.46	(21,452.20)	(200.12)	(161.95)	(161.32)				(236.80)
2000	425.89	(42,406.02)	(9,957.04)	(158.26)	(174.76)				(577.05)
2001	9,580.66	(43,904.92)	(458.27)	(120.49)	(183.25)				(623.26)
2002	55,114.72	(29,957.70)	(54.36)	(88.42)	(164.31)				(200.52)
2003	3,090.21	(31,697.69)	(1,025.75)	(129.42)	(171.35)				(214.64)
2004	42,710.73	(27,576.34)	(64.57)	(64.57)	(160.51)				(158.26)
2005	41,094.69	(32,866.90)	(79.98)	(72.12)	(153.35)				(109.51)
2006	166,285.17	(41,435.50)	(24.92)	(40.74)	(119.35)				(53.04)
2007	54,109.73	(38,526.09)	(71.20)	(46.16)	(115.53)				(56.01)
TOTAL		<u>682,301.87</u>							
							</		

ORANGE AND ROCKLAND UTILITIES, INC.
SUMMARY OF HISTORICAL NET SALVAGE

ACCOUNT	385000	INDUSTRIAL MEAS/REG EQUIPMENT							
		BOOK COST OF PLANT RETIRED	AMOUNT \$\$	N E T S A L V A G E				5 YEAR ROLLING BAND %	
				PERCENTAGE OF BOOK COST RETIRED					
				ONE YEAR BAND %	SHRINKING BAND ENDING				
YEAR				IN 2007	IN 1983				
				%	%	%			
1983	4,185.44	(264.42)	(6.32)	(2.08)	(6.32)				
1984	0.00	0.00	0.00	(1.91)	(6.32)				
1985	2,524.82	0.00	0.00	(1.91)	(3.94)				
1986	0.00	0.00	0.00	(1.96)	(3.94)				
1987	0.00	0.00	0.00	(1.96)	(3.94)			(3.94)	
1988	0.00	(307.85)	**	(1.96)	(8.53)			(12.19)	
1989	423.10	(50.57)	(11.95)	(1.67)	(8.73)			(12.16)	
1990	0.00	(646.52)	**	(1.62)	(17.79)			(237.52)	
1991	0.00	0.00	0.00	(1.01)	(17.79)			(237.52)	
1992	10,321.37	(1,053.72)	(10.21)	(1.01)	(13.31)			(19.16)	
1993	0.00	0.00	0.00	0.00	(13.31)			(16.29)	
1994	6,977.82	0.00	0.00	0.00	(9.51)			(9.83)	
1995	3,066.52	0.00	0.00	0.00	(8.45)			(5.17)	
1996	0.00	0.00	0.00	0.00	(8.45)			(5.17)	
1997	0.00	0.00	0.00	0.00	(8.45)			0.00	
1998	0.00	0.00	0.00	0.00	(8.45)			0.00	
1999	0.00	0.00	0.00	0.00	(8.45)			0.00	
2000	0.00	0.00	0.00	0.00	(8.45)			0.00	
2001	0.00	0.00	0.00	0.00	(8.45)			0.00	
2002	0.00	0.00	0.00	0.00	(8.45)			0.00	
2003	84,337.35	0.00	0.00	0.00	(2.08)			0.00	
2004	0.00	0.00	0.00	**	(2.08)			0.00	
2005	53,517.26	0.00	0.00	0.00	(1.40)			0.00	
2006	0.00	(663.00)	**	(1.24)	(1.81)			(0.48)	
2007	0.00	0.00	0.00	0.00	(1.81)			(0.48)	
TOTAL	165,353.68	(2,986.08)							

ORANGE AND ROCKLAND UTILITIES, INC.
SUMMARY OF HISTORICAL NET SALVAGE

ACCOUNT	386000	OTHER PROP. ON CUSTOMER PREMISES							
		BOOK COST OF PLANT RETIRED \$\$	N E T		PERCENTAGE OF BOOK COST RETIRED				
			AMOUNT \$\$	ONE YEAR BAND %	SHRINKING BAND		5 YEAR ROLLING BAND		
					IN 2007 %	ENDING IN 1983 %		%	
YEAR									
1983		0.00	0.00	0.00	0.00	0.00			0.00
1984		0.00	0.00	0.00	0.00	0.00			0.00
1985		0.00	0.00	0.00	0.00	0.00			0.00
1986		0.00	0.00	0.00	0.00	0.00			0.00
1987		0.00	0.00	0.00	0.00	0.00			0.00
1988		0.00	0.00	0.00	0.00	0.00			0.00
1989		0.00	0.00	0.00	0.00	0.00			0.00
1990		0.00	0.00	0.00	0.00	0.00			0.00
1991		0.00	0.00	0.00	0.00	0.00			0.00
1992		0.00	0.00	0.00	0.00	0.00			0.00
1993		0.00	0.00	0.00	0.00	0.00			0.00
1994		0.00	0.00	0.00	0.00	0.00			0.00
1995		0.00	0.00	0.00	0.00	0.00			0.00
1996		0.00	0.00	0.00	0.00	0.00			0.00
1997		0.00	0.00	0.00	0.00	0.00			0.00
1998		0.00	0.00	0.00	0.00	0.00			0.00
1999		0.00	0.00	0.00	0.00	0.00			0.00
2000		0.00	0.00	0.00	0.00	0.00			0.00
2001		0.00	0.00	0.00	0.00	0.00			0.00
2002		0.00	0.00	0.00	0.00	0.00			0.00
2003		20,141.42	0.00	0.00	0.00	0.00			0.00
2004		0.00	0.00	**	0.00	0.00			0.00
2005		13,025.61	0.00	0.00	0.00	0.00			0.00
2006		11,343.70	0.00	0.00	0.00	0.00			0.00
2007		0.00	0.00	0.00	0.00	0.00			0.00
TOTAL		44,510.73							

ORANGE AND ROCKLAND UTILITIES, INC.
SUMMARY OF HISTORICAL NET SALVAGE

ACCOUNT		390000	STRUCTURES AND IMPROVEMENTS								
YEAR	BOOK COST OF PLANT RETIRED	AMOUNT	N E T				PERCENTAGE OF BOOK COST RETIRED				
			ONE YEAR		SHRINKING BAND ENDING		5 YEAR				
			BAND	%	IN 2007	%	IN 1983	%	ROLLING BAND	%	
	\$ \$	\$ \$									
1983	98,356.22	(59,461.56)	(60.46)		(33.19)		(60.46)				
1984	26,605.40	(15,064.30)	(56.62)		(32.69)		(59.64)				
1985	11,864.42	(33,120.03)	(279.15)		(32.58)		(78.67)				
1986	548,520.83	(72,625.73)	(13.24)		(32.03)		(26.30)				
1987	100,262.57	(57,048.25)	(56.90)		(34.18)		(30.21)				(30.21)
1988	211,109.69	(21,988.64)	(10.42)		(33.70)		(26.02)				(22.25)
1989	93,115.31	(23,263.98)	(24.98)		(34.80)		(25.93)				(21.56)
1990	46,844.68	(17,589.08)	(37.55)		(35.01)		(26.41)				(19.25)
1991	150,501.54	(19,757.06)	(13.13)		(34.98)		(24.85)				(23.20)
1992	169,552.59	(30,126.09)	(17.77)		(35.77)		(24.03)				(16.80)
1993	162,651.47	(3,910.78)	(2.40)		(36.53)		(21.86)				(15.20)
1994	98,555.41	(15,809.49)	(16.04)		(37.98)		(21.52)				(13.88)
1995	21,649.88	(14,099.86)	(65.13)		(38.56)		(22.07)				(13.88)
1996	159,837.93	(26,305.33)	(16.46)		(38.40)		(21.59)				(14.74)
1997	163,656.44	(31,993.81)	(19.55)		(39.39)		(21.43)				(15.19)
1998	55,101.52	(22,980.47)	(41.71)		(40.34)		(21.96)				(22.29)
1999	43,349.31	(36,915.44)	(85.16)		(40.32)		(23.23)				(29.82)
2000	177,060.68	(11,326.13)	(6.40)		(39.73)		(21.95)				(21.62)
2001	185,547.11	(58,608.23)	(31.59)		(41.63)		(22.66)				(25.90)
2002	960,634.22	(998,849.38)	(103.98)		(42.26)		(45.08)				(79.39)
2003	721,072.01	(42,657.06)	(5.92)		(12.20)		(38.36)				(55.01)
2004	1,251,413.81	(198,036.56)	(15.83)		(15.83)		(33.19)				(39.73)
2005	1,084,966.23	(53,747.97)	(4.95)		(10.78)		(28.51)				0.00
2006	501,724.48	(81,587.34)	(16.26)		(11.75)		(27.64)				0.00
2007	854,951.53	(203,788.43)	(23.84)		(14.55)		(27.23)				0.00
TOTAL	7,898,905.28	(2,150,661.00)									

ORANGE AND ROCKLAND UTILITIES, INC.
SUMMARY OF HISTORICAL NET SALVAGE

ACCOUNT	391100	OFFICE FURN/EQUIP-FURNITURE										
		BOOK COST OF PLANT RETIRED	AMOUNT	N	E	T	PERCENTAGE OF BOOK COST				5 YEAR ROLLING BAND	
							RETIRED	ONE YEAR BAND	SHRINKING BAND			ENDING
									IN 2007	IN 1983		
YEAR		5 YEAR ROLLING BAND	%	%	%	%	%	%	%	%	%	
1983	9,390.52	0.00	0.00	9.91	0.00	0.00	0.01	0.01	0.01	0.01	0.01	
1984	366.25	85.00	23.21	9.95	0.87	0.87	0.60	0.60	0.60	0.60	0.60	
1985	4,477.14	0.00	0.00	9.95	0.60	0.60	0.01	0.01	0.01	0.01	0.01	
1986	701,236.20	0.00	0.00	9.97	0.01	0.01	0.01	0.01	0.01	0.01	0.01	
1987	(15,299.04)	0.00	*	13.99	0.01	0.01	0.01	0.01	0.01	0.01	0.01	
1988	9,700.71	0.00	0.00	13.87	0.01	0.01	0.01	0.01	0.01	0.01	0.01	
1989	1,632.99	0.00	0.00	13.95	0.01	0.01	0.01	0.01	0.01	0.01	0.01	
1990	9,889.65	0.00	0.00	13.96	0.01	0.01	0.01	0.01	0.01	0.01	0.01	
1991	57,123.04	0.00	0.00	14.04	0.01	0.01	0.01	0.01	0.01	0.01	0.01	
1992	48,418.20	1,650.65	3.41	14.52	0.21	0.21	0.21	0.21	0.21	0.21	0.21	
1993	182,669.68	6,099.09	3.34	14.85	0.78	0.78	0.78	0.78	0.78	0.78	0.78	
1994	189,624.26	33,076.73	17.44	16.31	3.41	3.41	3.41	3.41	3.41	3.41	3.41	
1995	663.24	2,381.00	359.00	16.14	3.61	3.61	3.61	3.61	3.61	3.61	3.61	
1996	1,141.22	139.79	12.25	15.96	3.62	3.62	3.62	3.62	3.62	3.62	3.62	
1997	214.87	3,325.00	1,547.45	15.96	3.89	3.89	3.89	3.89	3.89	3.89	3.89	
1998	7,581.78	3,325.00	43.86	15.70	4.14	4.14	4.14	4.14	4.14	4.14	4.14	
1999	150.35	0.00	0.00	15.52	4.14	4.14	4.14	4.14	4.14	4.14	4.14	
2000	21,542.71	(3,325.00)	(15.43)	15.53	3.80	3.80	3.80	3.80	3.80	3.80	3.80	
2001	94,528.34	0.00	0.00	16.07	3.53	3.53	3.53	3.53	3.53	3.53	3.53	
2002	334,863.49	196,269.78	58.61	17.42	14.64	14.64	14.64	14.64	14.64	14.64	14.64	
2003	673,142.10	0.00	0.00	0.00	10.42	10.42	10.42	10.42	10.42	10.42	10.42	
2004	118,677.73	0.00	0.00	0.00	9.91	9.91	9.91	9.91	9.91	9.91	9.91	
2005	159,001.10	0.00	0.00	0.00	9.31	9.31	9.31	9.31	9.31	9.31	9.31	
2006	79,689.30	0.00	0.00	0.00	9.03	9.03	9.03	9.03	9.03	9.03	9.03	
2007	194,338.68	0.00	0.00	0.00	8.42	8.42	8.42	8.42	8.42	8.42	8.42	
TOTAL	2,884,764.51	243,027.04										

ORANGE AND ROCKLAND UTILITIES, INC.
SUMMARY OF HISTORICAL NET SALVAGE

ACCOUNT	391200	OFFICE FURN/EQUIP-OFFICE MACHINES						
		BOOK COST OF PLANT RETIRED	N E T	PERCENTAGE OF BOOK COST RETIRED			5 YEAR ROLLING BAND %	
				AMOUNT \$ \$	ONE YEAR BAND	SHRINKING BAND ENDING		
					%	IN 2007		IN 1983
YEAR					%	%	%	
1983		230,609.49		0.42	1.91	0.42		
1984		19,786.32		12.23	2.21	1.35		
1985		1,530.70		0.00	2.03	1.34		
1986		0.00		0.00	2.03	1.34		
1987		0.00		0.00	2.03	1.34	1.34	
1988		0.00		**	2.03	1.74	16.04	
1989		67,212.86		25.44	1.95	6.73	26.33	
1990		11,036.40		8.15	0.47	6.78	24.28	
1991		36,788.73		0.00	0.39	6.10	16.52	
1992		24,405.15		(1.27)	0.40	5.64	13.40	
1993		55,285.58		7.90	0.44	5.92	11.33	
1994		29,191.22		0.00	0.01	5.56	3.16	
1995		16,303.81		0.00	0.01	5.37	2.51	
1996		5,126.83		0.00	0.01	5.32	3.11	
1997		27,689.22		0.00	0.01	5.04	3.27	
1998		18,068.47		0.00	0.01	4.87	0.00	
1999		2,316.38		0.00	0.01	4.85	0.00	
2000		1,695.50		2.95	0.01	4.84	0.09	
2001		344,157.36		0.00	0.00	2.97	0.01	
2002		388,344.78		0.00	0.00	2.07	0.01	
2003		51,251.70		0.00	0.00	1.99	0.01	
2004		57,529.83		0.00	0.00	1.91	0.01	
2005		171,616.90		0.00	0.00	1.70	0.00	
2006		49,669.30		1.01	0.18	1.68	0.00	
2007		223,868.90		0.00	0.10	1.47	0.00	
TOTAL		1,833,485.43		26,988.00				

ORANGE AND ROCKLAND UTILITIES, INC.
SUMMARY OF HISTORICAL NET SALVAGE

ACCOUNT		391700	OFFICE FURN/EQUIP-P/C EQUIPMENT & COMM. EQUIP. TELE SYS COMPUTER								
YEAR	BOOK COST OF PLANT RETIRED	AMOUNT	N	E	T	PERCENTAGE OF BOOK COST RETIRED				5 YEAR ROLLING BAND	
						ONE YEAR BAND	SHRINKING BAND ENDING				
							IN 2007	IN 1983	%		
											%
1983		\$									
1984	0.00		0.00					0.61	0.00		
1985	48,553.70		16,150.00					0.61	33.26		
1986	0.00		(4,462.50)					0.51	24.07		
1987	60,978.96		17,231.26					0.54	26.40		
1988	0.00		0.00					0.42	26.40		26.40
1989	0.00		0.00					0.42	26.40		26.40
1990	201,053.65		20,500.00					0.42	15.91		12.70
1991	43,773.89		0.00					0.29	13.95		12.34
1992	140,241.08		5,574.00					0.29	11.12		6.77
1993	95,790.06		1,312.50					0.25	9.54		5.70
1994	108,529.13		6,475.00					0.25	8.98		5.75
1995	440,579.33		0.00					0.20	5.51		1.61
1996	125,111.40		1,000.00					0.21	5.04		1.58
1997	1,545,375.47		3,415.00					0.20	2.39		0.53
1998	192,317.33		0.00					0.20	2.24		0.45
1999	2,310,585.85		27,325.00					0.20	1.78		0.69
2000	940,328.01		2,730.00					(0.03)	1.56		0.67
2001	99,072.26		75.00					(0.07)	1.53		0.66
2002	1,760,274.38		(5,206.18)					(0.07)	1.14		0.47
2003	1,479,860.47		(1,615.97)					(0.01)	0.94		0.35
2004	3,523,106.58		1,000.00					0.03	0.70		(0.04)
2005	1,819,197.18		0.00					0.00	0.61		(0.07)
2006	3,007,928.37		2,377.81					0.05	0.52		0.00
2007	1,204,242.67		0.00					0.04	0.49		0.00
	4,153,584.58		0.00					0.02	0.40		0.00
TOTAL	23,300,484.35		93,880.92								

ORANGE AND ROCKLAND UTILITIES, INC.
SUMMARY OF HISTORICAL NET SALVAGE

ACCOUNT		392100	TRANSP EQUIP-PASSENGER CARS & LIGHT TRUCKS																						
YEAR	BOOK COST OF PLANT RETIRED	\$	AMOUNT	N		E		T		S		A		L		V		A		G		E		5 YEAR ROLLING BAND %	
				ONE YEAR BAND	%	SHRINKING BAND ENDING IN 2007	%	IN 1983	%	IN 1983	%	IN 1983	%	IN 1983	%	IN 1983	%	IN 1983	%	IN 1983	%	IN 1983	%		
1983	539,132.24	148,267.16	27.50	14.91	27.50	14.91	27.50	14.91	27.50	14.91	27.50	14.91	27.50	14.91	27.50	14.91	27.50	14.91	27.50	14.91	27.50	14.91	27.50	14.91	27.50
1984	81,884.56	32,639.25	39.86	14.30	29.13	14.30	29.13	14.30	29.13	14.30	29.13	14.30	29.13	14.30	29.13	14.30	29.13	14.30	29.13	14.30	29.13	14.30	29.13	14.30	29.13
1985	67,294.34	22,300.00	33.14	14.10	29.52	14.10	29.52	14.10	29.52	14.10	29.52	14.10	29.52	14.10	29.52	14.10	29.52	14.10	29.52	14.10	29.52	14.10	29.52	14.10	29.52
1986	25,390.03	6,085.00	23.97	13.99	29.32	13.99	29.32	13.99	29.32	13.99	29.32	13.99	29.32	13.99	29.32	13.99	29.32	13.99	29.32	13.99	29.32	13.99	29.32	13.99	29.32
1987	1,360,942.27	200,635.95	14.74	13.96	19.76	13.96	19.76	13.96	19.76	13.96	19.76	13.96	19.76	13.96	19.76	13.96	19.76	13.96	19.76	13.96	19.76	13.96	19.76	13.96	19.76
1988	152,737.87	29,230.23	19.14	13.85	19.72	13.85	19.72	13.85	19.72	13.85	19.72	13.85	19.72	13.85	19.72	13.85	19.72	13.85	19.72	13.85	19.72	13.85	19.72	13.85	19.72
1989	1,382,620.47	230,242.76	16.65	13.77	18.54	13.77	18.54	13.77	18.54	13.77	18.54	13.77	18.54	13.77	18.54	13.77	18.54	13.77	18.54	13.77	18.54	13.77	18.54	13.77	18.54
1990	655,442.73	67,214.18	10.25	13.26	17.27	13.26	17.27	13.26	17.27	13.26	17.27	13.26	17.27	13.26	17.27	13.26	17.27	13.26	17.27	13.26	17.27	13.26	17.27	13.26	17.27
1991	427,162.53	34,130.29	7.99	13.53	16.42	13.53	16.42	13.53	16.42	13.53	16.42	13.53	16.42	13.53	16.42	13.53	16.42	13.53	16.42	13.53	16.42	13.53	16.42	13.53	16.42
1992	895,221.73	146,806.65	16.40	13.88	14.45	13.88	14.45	13.88	14.45	13.88	14.45	13.88	14.45	13.88	14.45	13.88	14.45	13.88	14.45	13.88	14.45	13.88	14.45	13.88	14.45
1993	629,895.12	135,225.03	21.47	13.50	15.38	13.50	15.38	13.50	15.38	13.50	15.38	13.50	15.38	13.50	15.38	13.50	15.38	13.50	15.38	13.50	15.38	13.50	15.38	13.50	15.38
1994	352,750.20	102,075.16	28.94	12.57	16.40	12.57	16.40	12.57	16.40	12.57	16.40	12.57	16.40	12.57	16.40	12.57	16.40	12.57	16.40	12.57	16.40	12.57	16.40	12.57	16.40
1995	931,381.05	161,458.21	17.34	11.41	17.91	11.41	17.91	11.41	17.91	11.41	17.91	11.41	17.91	11.41	17.91	11.41	17.91	11.41	17.91	11.41	17.91	11.41	17.91	11.41	17.91
1996	0.00	0.00	0.00	10.06	19.42	10.06	19.42	10.06	19.42	10.06	19.42	10.06	19.42	10.06	19.42	10.06	19.42	10.06	19.42	10.06	19.42	10.06	19.42	10.06	19.42
1997	890,836.70	108,371.60	12.17	10.06	18.08	10.06	16.98	10.06	16.98	10.06	16.98	10.06	16.98	10.06	16.98	10.06	16.98	10.06	16.98	10.06	16.98	10.06	16.98	10.06	16.98
1998	0.00	0.00	0.00	9.48	17.10	9.48	16.98	9.48	16.98	9.48	16.98	9.48	16.98	9.48	16.98	9.48	16.98	9.48	16.98	9.48	16.98	9.48	16.98	9.48	16.98
1999	81,081.16	66,168.53	81.61	9.48	17.65	9.48	17.59	9.48	17.59	9.48	17.59	9.48	17.59	9.48	17.59	9.48	17.59	9.48	17.59	9.48	17.59	9.48	17.59	9.48	17.59
2000	1,578,117.70	101,138.18	6.41	7.59	10.81	7.59	15.84	7.59	15.84	7.59	15.84	7.59	15.84	7.59	15.84	7.59	15.84	7.59	15.84	7.59	15.84	7.59	15.84	7.59	15.84
2001	33,324.30	36,405.92	109.25	8.82	12.08	8.82	16.15	8.82	16.15	8.82	16.15	8.82	16.15	8.82	16.15	8.82	16.15	8.82	16.15	8.82	16.15	8.82	16.15	8.82	16.15
2002	388,467.64	19,472.04	5.01	6.58	10.72	6.58	15.73	6.58	15.73	6.58	15.73	6.58	15.73	6.58	15.73	6.58	15.73	6.58	15.73	6.58	15.73	6.58	15.73	6.58	15.73
2003	739,469.45	45,100.70	6.10	7.13	9.51	7.13	15.10	7.13	15.10	7.13	15.10	7.13	15.10	7.13	15.10	7.13	15.10	7.13	15.10	7.13	15.10	7.13	15.10	7.13	15.10
2004	369,324.13	33,981.25	9.20	9.20	7.59	9.20	14.91	9.20	14.91	9.20	14.91	9.20	14.91	9.20	14.91	9.20	14.91	9.20	14.91	9.20	14.91	9.20	14.91	9.20	14.91
2005	0.00	0.00	0.00	9.20	0.00	9.20	0.00	14.91	0.00	14.91	0.00	14.91	0.00	14.91	0.00	14.91	0.00	14.91	0.00	14.91	0.00	14.91	0.00	14.91	0.00
2006	1,211,213.77	21,450.00	1.77	3.51	0.00	3.51	13.67	3.51	13.67	3.51	13.67	3.51	13.67	3.51	13.67	3.51	13.67	3.51	13.67	3.51	13.67	3.51	13.67	3.51	13.67
2007	734,623.70	33,750.00	4.59	3.85	0.00	3.85	13.17	3.85	13.17	3.85	13.17	3.85	13.17	3.85	13.17	3.85	13.17	3.85	13.17	3.85	13.17	3.85	13.17	3.85	13.17
TOTAL	13,528,313.69	1,782,148.09																							

ORANGE AND ROCKLAND UTILITIES, INC.
SUMMARY OF HISTORICAL NET SALVAGE

ACCOUNT		392300	TRANSP EQUIP-HEAVY TRUCKS & TRAILERS									
YEAR	BOOK COST OF PLANT RETIRED	AMOUNT	N	E	T	PERCENTAGE OF BOOK COST RETIRED					5 YEAR ROLLING BAND %	
						ONE YEAR BAND	SHRINKING BAND ENDING					
							IN 2007	A	V	G		E
		\$				%					%	
1983	35,949.72	2,063.72				5.74		11.38		5.74		
1984	0.00	0.00				0.00		11.40		5.74		
1985	0.00	0.00				0.00		11.40		5.74		
1986	45,766.03	0.00				0.00		11.40		2.53		
1987	82,295.76	38,492.50				46.77		11.44		24.73	24.73	
1988	248,939.91	55,123.62				22.14		11.22		23.17	24.83	
1989	578,483.71	111,053.66				19.20		11.02		20.85	21.42	
1990	370,141.41	56,873.57				15.37		10.64		19.36	19.73	
1991	1,262,746.84	107,213.59				8.49		10.50		14.13	14.50	
1992	980,008.77	114,629.71				11.70		10.73		13.47	12.93	
1993	961,336.41	125,788.54				13.08		10.64		13.39	12.41	
1994	0.00	0.00				0.00		10.38		13.39	11.32	
1995	995,982.57	114,056.43				11.45		10.38		13.04	10.99	
1996	0.00	0.00				0.00		10.25		13.04	12.07	
1997	2,022,696.87	220,911.28				10.92		10.25		12.48	11.58	
1998	0.00	0.00				0.00		10.03		12.48	11.10	
1999	535,666.27	191,950.05				35.83		10.03		14.02	14.82	
2000	2,885,890.46	204,682.11				7.09		7.54		12.20	11.34	
2001	0.00	66,575.07				**		8.03		12.81	12.57	
2002	0.00	0.00				0.00		5.55		12.81	13.54	
2003	1,038,594.28	37,856.59				3.64		5.55		12.02	11.23	
2004	1,645,607.64	111,139.00				6.75		6.75		11.38	7.54	
2005	5,409.95	0.00				0.00		6.73		11.38	0.00	
2006	2,904,506.57	127,907.27				4.40		5.25		10.16	0.00	
2007	1,272,996.07	108,512.50				8.52		5.96		10.04	0.00	
TOTAL	17,873,019.24	1,794,829.21										

ORANGE AND ROCKLAND UTILITIES, INC.
SUMMARY OF HISTORICAL NET SALVAGE

ACCOUNT	393000	STORES EQUIPMENT							
		BOOK COST OF PLANT RETIRED	N E T	PERCENTAGE OF BOOK COST RETIRED				5 YEAR ROLLING BAND %	
				AMOUNT	ONE YEAR BAND		SHRINKING BAND ENDING		
					\$	%	IN 2007		IN 1983
YEAR									
1983	6,607.16	6,132.27	92.81	2.19	92.81				
1984	0.00	0.00	0.00	(2.11)	92.81				
1985	0.00	0.00	0.00	(2.11)	92.81				
1986	7,959.49	0.00	0.00	(2.11)	42.10				
1987	26,206.99	0.00	0.00	(2.24)	15.04		15.04		
1988	0.00	0.00	0.00	(2.80)	15.04		0.00		
1989	0.00	0.00	0.00	(2.80)	15.04		0.00		
1990	0.00	0.00	0.00	(2.80)	15.04		0.00		
1991	0.00	0.00	0.00	(2.80)	15.04		0.00		
1992	450.28	0.00	0.00	(2.80)	14.88		0.00		
1993	24,718.89	0.00	0.00	(2.81)	9.30		0.00		
1994	10,448.42	(2,940.68)	(28.14)	(3.68)	4.18		(8.26)		
1995	507.16	0.00	0.00	0.00	4.15		(8.14)		
1996	302.00	0.00	0.00	0.00	4.13		(8.07)		
1997	0.00	0.00	0.00	0.00	4.13		(8.17)		
1998	0.00	0.00	0.00	0.00	4.13		(26.12)		
1999	35,237.94	0.00	0.00	0.00	2.84		0.00		
2000	0.00	0.00	0.00	0.00	2.84		0.00		
2001	835.54	0.00	0.00	0.00	2.82		0.00		
2002	2,410.14	0.00	0.00	0.00	2.76		0.00		
2003	19,318.66	0.00	0.00	0.00	2.36		0.00		
2004	10,913.00	0.00	0.00	0.00	2.19		0.00		
2005	42,129.43	(1,053.00)	(2.50)	(1.99)	1.14		0.00		
2006	55,192.41	0.00	0.00	(0.97)	0.88		0.00		
2007	3,146.69	0.00	0.00	(0.95)	0.87		0.00		
TOTAL	246,384.20	2,138.59							

ORANGE AND ROCKLAND UTILITIES, INC.
SUMMARY OF HISTORICAL NET SALVAGE

ACCOUNT		394000	TOOLS, SHOP AND WORK EQUIPMENT						
YEAR	BOOK COST OF PLANT RETIRED	AMOUNT	N	E	T	PERCENTAGE OF BOOK COST RETIRED			5 YEAR ROLLING BAND %
						ONE YEAR BAND	SHRINKING BAND ENDING		
							IN 2007	IN 1983	
	\$	\$				%	%	%	
1983	66,144.50	6,087.67				9.20	0.67	9.20	
1984	0.00	0.00				0.00	0.19	9.20	
1985	267.93	0.00				0.00	0.19	9.17	
1986	634,637.43	150.00				0.02	0.19	0.89	
1987	(1,890.08)	1,461.11				*	0.38	1.10	1.10
1988	0.00	0.00				0.00	0.11	1.10	0.25
1989	185.86	0.00				0.00	0.11	1.10	0.25
1990	0.00	0.00				0.00	0.11	1.10	0.25
1991	1,193.53	0.00				0.00	0.11	1.10	*
1992	20,006.76	528.24				2.64	0.11	1.14	2.47
1993	24,118.08	842.01				3.49	0.01	1.22	3.01
1994	202.32	0.00				0.00	(0.17)	1.22	3.01
1995	741.50	(7,999.53)				(1,078.83)	(0.17)	0.14	(14.33)
1996	1,396.92	0.00				0.00	1.48	0.14	(14.27)
1997	19,453.59	6,244.01				32.10	1.48	0.95	(1.99)
1998	2,597.32	0.00				0.00	0.20	0.95	(7.20)
1999	353.49	0.00				0.00	0.21	0.95	(7.15)
2000	32,743.38	0.00				0.00	0.21	0.91	11.04
2001	66,534.05	0.00				0.00	0.22	0.84	5.13
2002	164,089.90	0.00				0.00	0.26	0.71	0.00
2003	122,308.12	0.00				0.00	0.48	0.63	0.00
2004	76,622.10	950.60				1.24	1.24	0.67	0.21
2005	65,562.40	0.00				0.00	0.67	0.64	0.00
2006	159,875.77	150.00				0.09	0.36	0.58	0.00
2007	182,801.31	5,065.00				2.77	1.27	0.82	0.00
TOTAL	1,639,946.18	13,479.11							

ORANGE AND ROCKLAND UTILITIES, INC.
SUMMARY OF HISTORICAL NET SALVAGE

ACCOUNT	395000	LABORATORY EQUIPMENT								
		BOOK COST OF PLANT RETIRED	AMOUNT \$	N	E	T	PERCENTAGE OF BOOK COST RETIRED			5 YEAR ROLLING BAND %
							ONE YEAR BAND	SHRINKING BAND ENDING		
								IN 2007	IN 1983	
YEAR										
1983		0.00	0.00					0.10	0.00	
1984		0.00	0.00					0.10	0.00	
1985		0.00	0.00					0.10	0.00	
1986		715.12	0.00					0.10	0.00	
1987		4,402.82	0.00					0.10	0.00	
1988		0.00	0.00					0.10	0.00	0.00
1989		8,886.80	(1,206.95)				(13.58)	0.10	0.00	0.00
1990		1,744.00	0.00				0.00	0.23	(8.62)	(8.62)
1991		182,740.14	0.00				0.00	0.23	(7.66)	(7.66)
1992		51,681.80	0.00				0.00	0.29	(0.61)	(0.61)
1993		47,209.17	0.00				0.00	0.31	(0.48)	(0.49)
1994		17,126.63	0.00				0.00	0.33	(0.41)	(0.41)
1995		452.60	0.00				0.00	0.34	(0.38)	0.00
1996		8,612.81	0.00				0.00	0.34	(0.37)	0.00
1997		0.00	0.00				0.00	0.35	(0.37)	0.00
1998		6,878.38	325.00				4.72	0.35	(0.27)	0.98
1999		0.00	0.00				0.00	0.30	(0.27)	2.04
2000		16,180.30	0.00				0.00	0.30	(0.25)	1.03
2001		96,188.94	(36.45)				(0.04)	0.31	(0.21)	0.24
2002		255,048.78	(200.00)				(0.08)	0.38	(0.16)	0.02
2003		126,665.47	2,000.00				1.58	0.89	0.11	0.36
2004		97,265.43	0.00				0.00	0.00	0.10	0.30
2005		205,068.46	0.00				0.00	0.00	0.08	0.23
2006		75,918.29	5,000.00				6.59	1.32	0.49	0.89
2007		111,528.72	0.00				0.00	1.02	0.45	1.14
TOTAL		1,314,314.66	5,881.60							

ORANGE AND ROCKLAND UTILITIES, INC.
SUMMARY OF HISTORICAL NET SALVAGE

ACCOUNT	396000	POWER OPERATED EQUIPMENT & POW. OPER. EQUIP. NON FLEET									
		YEAR	BOOK COST OF PLANT RETIRED \$\$	N E T	PERCENTAGE OF BOOK COST RETIRED				5 YEAR ROLLING BAND %		
					AMOUNT \$\$	ONE YEAR	SHRINKING BAND ENDING				
						BAND %	IN 2007	IN 1983			
1983		16,195.00	2,772.43	17.12	24.64	17.12					
1984		0.00	0.00	0.00	24.74	17.12					
1985		0.00	0.00	0.00	24.74	17.12					
1986		0.00	0.00	0.00	24.74	17.12					
1987		76,615.90	39,587.48	51.67	24.74	45.64				45.64	
1988		18,215.57	8,217.47	45.11	22.91	45.55				50.41	
1989		5,477.20	2,431.50	44.39	22.54	45.50				50.08	
1990		60,487.65	0.00	0.00	22.43	29.95				31.24	
1991		817.51	556.47	68.07	23.74	30.13				31.43	
1992		76,779.43	3,422.60	4.46	23.70	22.38				9.04	
1993		34,213.20	4,600.27	13.45	25.23	21.33				6.19	
1994		0.00	0.00	0.00	25.67	21.33				4.98	
1995		170,299.70	62,412.40	36.65	25.67	27.01				25.16	
1996		0.00	0.00	0.00	23.20	27.01				25.04	
1997		82,816.43	20,927.92	25.27	23.20	26.74				30.61	
1998		0.00	0.00	0.00	22.95	26.74				32.93	
1999		43,560.97	14,254.99	32.72	22.95	27.19				32.90	
2000		177,859.44	12,873.43	7.24	22.28	22.54				15.80	
2001		4,039.07	3,996.80	98.95	28.16	22.94				16.89	
2002		0.00	0.00	0.00	27.52	22.94				13.81	
2003		491,515.91	52,260.01	10.63	27.52	18.14				11.63	
2004		(40,424.94)	71,895.75	*	*	24.64				22.28	
2005		139,432.20	29,500.00	21.16	102.41	24.28				0.00	
2006		394,995.71	50,195.80	12.71	30.69	21.67				0.00	
2007		248,956.68	60,524.69	24.31	28.55	22.00				0.00	
TOTAL		2,001,852.63	440,430.01								

ORANGE AND ROCKLAND UTILITIES, INC.
SUMMARY OF HISTORICAL NET SALVAGE

ACCOUNT		397000	COMMUNICATION EQUIPMENT & COMM. EQUIP. TELE SYS EQUIP.									
YEAR	BOOK COST OF PLANT RETIRED	AMOUNT	N	E	T	PERCENTAGE OF BOOK COST RETIRED					5 YEAR ROLLING BAND %	
						ONE YEAR BAND	SHRINKING BAND ENDING					
							IN 2007	IN 1983	IN 1983	IN 1983		
												%
1983		\$										
1984	3,646.88	1,468.34	40.26					(0.88)		40.26		
1985	1,918.39	0.00	0.00					(0.92)		26.38		
1986	3,861.60	0.00	0.00					(0.92)		15.58		
1987	126,384.49	(17,819.13)	(14.10)					(0.92)		(12.04)		
1988	1,284.90	0.00	0.00					(0.50)		(11.93)		(11.93)
1989	18,989.03	(6,727.56)	(35.43)					(0.50)		(14.79)		(16.10)
1990	35,572.47	(371.88)	(1.05)					(0.34)		(12.24)		(13.39)
1991	526,543.26	(2,600.00)	(0.49)					(0.33)		(3.63)		(3.88)
1992	24,686.84	(2,298.25)	(9.31)					(0.30)		(3.82)		(1.98)
1993	126,322.03	(5,697.10)	(4.51)					(0.24)		(3.92)		(2.42)
1994	100,207.81	275.00	0.27					(0.07)		(3.48)		(1.31)
1995	54,877.42	(1,000.00)	(1.82)					(0.08)		(3.39)		(1.36)
1996	15,756.40	(398.90)	(2.53)					(0.05)		(3.38)		(2.83)
1997	18,224.62	0.00	0.00					(0.04)		(3.32)		(2.16)
1998	1,688.68	0.00	0.00					(0.04)		(3.32)		(0.59)
1999	350,213.12	0.00	0.00					(0.04)		(2.49)		(0.32)
2000	5,461.44	0.00	0.00					(0.04)		(2.48)		(0.10)
2001	8,364.43	0.00	0.00					(0.04)		(2.47)		0.00
2002	1,932,517.35	0.00	0.00					(0.04)		(1.05)		0.00
2003	402,592.32	(1,179.75)	(0.29)					(0.16)		(0.97)		(0.04)
2004	294,958.84	0.00	0.00					0.00		(0.90)		(0.04)
2005	59,705.99	0.00	0.00					0.00		(0.88)		(0.04)
2006	723,597.04	0.00	0.00					0.00		(0.75)		0.00
2007	23,922.46	0.00	0.00					0.00		(0.75)		0.00
	961,151.22	0.00	0.00					0.00		(0.62)		0.00
TOTAL	5,822,449.03	(36,349.23)										

ORANGE AND ROCKLAND UTILITIES, INC.
SUMMARY OF HISTORICAL NET SALVAGE

ACCOUNT	398000	MISCELLANEOUS EQUIPMENT							
		BOOK COST OF PLANT RETIRED	N E T	S A L V A G E	PERCENTAGE OF BOOK COST RETIRED			5 YEAR ROLLING BAND %	
					AMOUNT	ONE YEAR			SHRINKING BAND ENDING IN 1983
						BAND	%		
YEAR		\$							
1983		49,982.13	639.81	1.28	0.02	1.28			
1984		2,558.82	1,385.25	54.14	(0.08)	3.85			
1985		775.55	(180.75)	(23.31)	(0.30)	3.46			
1986		27,432.40	0.00	0.00	(0.27)	2.28			
1987		3,096.69	25.00	0.81	(0.28)	2.23			2.23
1988		27,301.09	(107.14)	(0.39)	(0.29)	1.59			1.83
1989		10,377.89	0.00	0.00	(0.28)	1.45			(0.38)
1990		5,478.92	(406.44)	(7.42)	(0.29)	1.07			(0.66)
1991		15,131.07	0.00	0.00	(0.22)	0.95			(0.80)
1992		125,932.56	0.00	0.00	(0.22)	0.51			(0.28)
1993		7,512.59	0.00	0.00	(0.29)	0.49			(0.25)
1994		6,371.13	1,200.00	18.83	(0.30)	0.91			0.49
1995		0.00	0.00	0.00	(0.61)	0.91			0.77
1996		4,576.94	0.00	0.00	(0.61)	0.89			0.83
1997		0.00	0.00	0.00	(0.61)	0.89			6.50
1998		0.00	0.00	0.00	(0.61)	0.89			10.96
1999		4,479.87	(160.88)	(3.59)	(0.61)	0.82			(1.78)
2000		25,893.77	0.00	0.00	(0.58)	0.76			(0.46)
2001		45,743.29	0.00	0.00	(0.62)	0.66			(0.21)
2002		35,180.33	0.00	0.00	(0.71)	0.60			(0.14)
2003		211,277.93	0.00	0.00	(0.80)	0.39			(0.05)
2004		68,519.11	(2,242.79)	(3.27)	(3.27)	0.02			(0.58)
2005		148,942.72	0.00	0.00	(1.03)	0.02			0.00
2006		116,186.88	0.00	0.00	(0.67)	0.02			0.00
2007		51,896.00	0.00	0.00	(0.58)	0.02			0.00
TOTAL		994,647.68		152.06					

ORANGE AND ROCKLAND UTILITIES, INC.

**NEGATIVE NET SALVAGE CAP ADJUSTMENT
FOR GAS MAINS & SERVICES
2003-2007**

NOVEMBER 2008

Orange and Rockland Utilities, Inc.
Negative Net Salvage Cap Adjustment for Gas Mains & Services
2003 - 2007

	<u>Mains</u>	<u>Services</u>
(A) Cumulative Retirements	2,386,765	1,029,909
(B) Cumulative Net Salvage	1,131,303	2,050,680
(C) Recover through Reserve (40%) of 2,386,765	(954,706)	
(D) Recover through Reserve (80%) of 1,029,909		(823,927)
(E) Recover through O&M	176,597	1,226,754
Adjustment for Inflation - 176,597 @ 5.30% through Mid Rate Year	185,957	
Adjustment for Inflation - 1,226,754 @ 5.30% through Mid Rate Year		1,291,771
Divided by 5 years	37,191	258,354
Annual Rate Year Adjustment (Rounded)	40,000	260,000
Existing Amortization	<u>(70,000)</u>	<u>(80,000)</u>
Net Adjustment	<u><u>(30,000)</u></u>	<u><u>180,000</u></u>

Note: Forecasts are based on the GDP Factor Inflation Rate

ORANGE AND ROCKLAND UTILITIES, INC.

GAS PLANT

**DETERMINATION OF THE UNRECOVERED COST OF LIQUEFIED PETROLEUM GAS
FACILITIES
AS OF JUNE 30, 2009**

NOVEMBER 2008

ORANGE AND ROCKLAND UTILITIES, INC.
GAS PLANT
DETERMINATION OF THE UNRECOVERED COST OF LIQUEFIED PETROLEUM GAS FACILITIES
AS OF JUNE 30, 2009

<u>STRUCTURES & IMPROVEMENT (A/C 305000)</u>	<u>BOOK COST</u>	<u>RESERVE</u>
ENDING BALANCE - AS OF DECEMBER 31, 2007	690,200	36,694
ESTIMATED DEPRECIATION EXPENSE (JANUARY 2008 - JUNE 2009)	-	(35,511)
<u>RECLASSIFICATION TO DISTRIBUTION PLANT</u>		
ESTIMATED BOOK COST TO BE TRANSFERRED	(225,973)	
ESTIMATED ACCRUED DEPRECIATION AT DECEMBER 31, 2007		11,863
ESTIMATED DEPRECIATION EXPENSE (JAN 2008 - JUN 2009)		(12,503)
TOTAL ESTIMATED ACCRUED DEPRECIATION AT JUNE 30, 2009		(640)
ESTIMATED RETIREMENT AT JUNE 2009	(464,227)	464,227
ESTIMATED UNRECOVERED COST AT JUNE 30, 2009	-	464,770
<u>LP GAS EQUIPMENT (A/C 311002)</u>		
ENDING BALANCE - AS OF DECEMBER 31, 2007	1,119,765	442,160
DEPRECIATION EXPENSE (JANUARY 2008 - JUNE 2009)	-	(72,729)
<u>RECLASSIFICATION TO DISTRIBUTION PLANT</u>		
ESTIMATED BOOK COST TO BE TRANSFERRED	(128,350)	
ESTIMATED ACCRUED DEPRECIATION AT DECEMBER 31, 2007		2,165
ESTIMATED DEPRECIATION EXPENSE (JAN 2008 - JUN 2009)		(6,850)
TOTAL ESTIMATED ACCRUED DEPRECIATION AT JUNE 30, 2009		(4,685)
ESTIMATED RETIREMENT AT JUNE 2009	(991,415)	991,415
ESTIMATED UNRECOVERED COST AT JUNE 30, 2009	-	1,356,162
TOTAL UNRECOVERED LP GAS FACILITIES AT JUNE 30, 2009	\$ -	\$ 1,820,932

EXHIBIT G-13
SCHEDULE 1

Present and Proposed Rates in Brief

ORANGE AND ROCKLAND UTILITIES, INC.

Present and Proposed Rates in Brief

Present S.C. No. 1 (Monthly)
(Residential and Space Heating)

Delivery Charges:

Delivery:

First	3 Ccf or less	\$14.00
Next	47 Ccf	34.283 ¢/Ccf
All over	50 Ccf	32.995 ¢/Ccf

Other Charges:

Merchant Function Charge:

Fixed Procurement	1.392 ¢/Ccf
Credit and Collections	0.703 ¢/Ccf
Storage WC (supply related)	1.838 ¢/Ccf
Uncollectibles	Variable

Plus: Gas Supply Charge
Plus: Monthly Gas Adjustment
Plus: Unauthorized Use of Gas
Plus: Increase in Rates and Charges
Plus: Systems Benefits Charge
Plus: Billing and Payment Processing Charge

Minimum Charge - \$14.00 per month

Proposed S.C. No. 1 (Monthly)
(Residential and Space Heating)

Delivery Charges:

Delivery:

First	3 Ccf or less	\$18.22
Next	47 Ccf	41.929 ¢/Ccf
All over	50 Ccf	40.354 ¢/Ccf

Other Charges:

Merchant Function Charge:

Fixed Procurement	1.127 ¢/Ccf
Credit and Collections	0.647 ¢/Ccf
Storage WC (supply related)	0.906 ¢/Ccf
Uncollectibles	Variable

Plus: Gas Supply Charge
Plus: Monthly Gas Adjustment
Plus: Unauthorized Use of Gas
Plus: Increase in Rates and Charges
Plus: Systems Benefits Charge
Plus: Billing and Payment Processing Charge
Plus: RDM Adjustment

Minimum Charge - \$18.22 per month

Present S.C. No. 2 (Monthly)
(General Service)

Delivery Charges:

First	3 Ccf or less	\$21.00
Next	47 Ccf	32.275 ¢/Ccf
Next	4,950 Ccf	30.987 ¢/Ccf
All over	5,000 Ccf	27.402 ¢/Ccf

Other Charges:

Merchant Function Charge:

Fixed Procurement	0.516 ¢/Ccf
Credit and Collections	0.311 ¢/Ccf
Storage WC (supply related)	1.838 ¢/Ccf
Uncollectibles	Variable

Plus: Gas Supply Charge
Plus: Monthly Gas Adjustment
Plus: Unauthorized Use of Gas
Plus: Increase in Rates and Charges
Plus: Billing and Payment Processing Charge

Minimum Charge - \$21.00 per month

Proposed S.C. No. 2 (Monthly)
(General Service)

Delivery Charges:

Delivery:

First	3 Ccf or less	\$27.33
Next	47 Ccf	34.258 ¢/Ccf
Next	4,950 Ccf	32.891 ¢/Ccf
All over	5,000 Ccf	29.085 ¢/Ccf

Other Charges:

Merchant Function Charge:

Fixed Procurement	0.394 ¢/Ccf
Credit and Collections	0.222 ¢/Ccf
Storage WC (supply related)	0.906 ¢/Ccf
Uncollectibles	Variable

Plus: Gas Supply Charge
Plus: Monthly Gas Adjustment
Plus: Unauthorized Use of Gas
Plus: Increase in Rates and Charges
Plus: Billing and Payment Processing Charge
Plus: RDM Adjustment

Minimum Charge - \$27.33 per month

ORANGE AND ROCKLAND UTILITIES, INC.

Present and Proposed Rates in Brief

Present S.C. No. 6 (Monthly)
(Firm Transportation Service)

Rate Schedule IA - Residential:

Delivery Charges:

First	3 Ccf or less	\$14.00
Next	47 Ccf	34.283 ¢/Ccf
All over	50 Ccf	32.995 ¢/Ccf

Other Charges:

Merchant Function Charge:	
Credit and Collections	0.703 ¢/Ccf

Plus: Monthly Gas Adjustment
Plus: Balancing Service (Optional)
Plus: Winter Bundled Sales Service (Optional)
Plus: Increase in Rates and Charges
Plus: Systems Benefits Charge
Plus: Billing and Payment Processing Charge*

Rate Schedule IB - Non-Residential:

Delivery Charges:

First	3 Ccf or less	\$21.00
Next	47 Ccf	32.275 ¢/Ccf
Next	4,950 Ccf	30.987 ¢/Ccf
All over	5,000 Ccf	27.402 ¢/Ccf

Other Charges:

Merchant Function Charge:	
Credit and Collections	0.311 ¢/Ccf

Plus: Monthly Gas Adjustment
Plus: Balancing Service (Optional)
Plus: Winter Bundled Sales Service (Optional)
Plus: Increase in Rates and Charges
Plus: Billing and Payment Processing Charge*

Rate Schedule II:

Delivery Charges:

First	100 Ccf or less	\$172.13
Over	100 Ccf	27.402 ¢/Ccf

Other Charges:

Merchant Function Charge:	
Credit and Collections	0.311 ¢/Ccf

Plus: Monthly Gas Adjustment
Plus: Balancing Service (Optional)
Plus: Winter Bundled Sales Service (Optional)
Plus: Increase in Rates and Charges
Plus: Billing and Payment Processing Charge*

Proposed S.C. No. 6 (Monthly)
(Firm Transportation Service)

Rate Schedule IA - Residential:

Delivery Charges:

Delivery:

First	3 Ccf or less	\$18.22
Next	47 Ccf	41.929 ¢/Ccf
All over	50 Ccf	40.354 ¢/Ccf

Other Charges:

Merchant Function Charge:	
Credit and Collections	0.000 ¢/Ccf

Plus: Monthly Gas Adjustment
Plus: Balancing Service (Optional)
Plus: Winter Bundled Sales Service (Optional)
Plus: Increase in Rates and Charges
Plus: Systems Benefits Charge
Plus: Billing and Payment Processing Charge*
Plus: RDM Adjustment

Rate Schedule IB - Non-Residential:

Delivery Charges:

Delivery:

First	3 Ccf or less	\$27.33
Next	47 Ccf	34.258 ¢/Ccf
Next	4,950 Ccf	32.891 ¢/Ccf
All over	5,000 Ccf	29.085 ¢/Ccf

Other Charges:

Merchant Function Charge:	
Credit and Collections	0.000 ¢/Ccf

Plus: Monthly Gas Adjustment
Plus: Balancing Service (Optional)
Plus: Winter Bundled Sales Service (Optional)
Plus: Increase in Rates and Charges
Plus: Billing and Payment Processing Charge*
Plus: RDM Adjustment

Rate Schedule II:

Delivery Charges:

Delivery:

First	100 Ccf or less	\$206.70
Over	100 Ccf	29.085 ¢/Ccf

Other Charges:

Merchant Function Charge:	
Credit and Collections	0.000 ¢/Ccf

Plus: Monthly Gas Adjustment
Plus: Balancing Service (Optional)
Plus: Winter Bundled Sales Service (Optional)
Plus: Increase in Rates and Charges
Plus: Billing and Payment Processing Charge*
Plus: RDM Adjustment

* Assessed on customers receiving a utility single bill
** Minimum charge set at the first block charge.

ORANGE AND ROCKLAND UTILITIES, INC.

Present and Proposed Rates in Brief

Present Rider B - Rate Schedule I Rate IA

Delivery Charges (Summer):

First	3 Ccf or less	\$106.00
All over	3 Ccf	16.795 ¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	\$106.00
All over	3 Ccf	20.849 ¢/Ccf

Minimum Charge - \$106.00 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification

Proposed Rider B - Rate Schedule I Rate IA

Delivery Charges (Summer):

First	3 Ccf or less	\$114.91
All over	3 Ccf	17.827 ¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	\$114.91
All over	3 Ccf	22.130 ¢/Ccf

Minimum Charge - \$114.91 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

Present Rider B - Rate Schedule I Rate IB

Delivery Charges (Summer):

First	3 Ccf or less	\$180.00
All over	3 Ccf	16.795 ¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	\$180.00
All over	3 Ccf	20.849 ¢/Ccf

Minimum Charge - \$180.00 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification

Proposed Rider B - Rate Schedule I Rate IB

Delivery Charges (Summer):

First	3 Ccf or less	\$195.14
All over	3 Ccf	17.827 ¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	\$195.14
All over	3 Ccf	22.130 ¢/Ccf

Minimum Charge - \$195.14 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

Present Rider B - Rate Schedule I Rate IC

Delivery Charges (Summer):

First	3 Ccf or less	\$274.00
All over	3 Ccf	16.795 ¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	\$274.00
All over	3 Ccf	20.849 ¢/Ccf

Minimum Charge - \$274.00 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification

Proposed Rider B - Rate Schedule I Rate IC

Delivery Charges (Summer):

First	3 Ccf or less	\$297.04
All over	3 Ccf	17.827 ¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	\$297.04
All over	3 Ccf	22.130 ¢/Ccf

Minimum Charge - \$297.04 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

* Excluding the RDM Adjustment

ORANGE AND ROCKLAND UTILITIES, INC.

Present and Proposed Rates in Brief

Present Rider B - Rate Schedule I Rate ID

Delivery Charges (Summer):

First	3 Ccf or less	\$348.00
All over	3 Ccf	16.795 ¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	\$348.00
All over	3 Ccf	20.849 ¢/Ccf

Minimum Charge - \$348.00 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification

Proposed Rider B - Rate Schedule I Rate ID

Delivery Charges (Summer):

First	3 Ccf or less	\$377.26
All over	3 Ccf	17.827 ¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	\$377.26
All over	3 Ccf	22.130 ¢/Ccf

Minimum Charge - \$377.26 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

Present Rider B - Rate Schedule II

Delivery Charges (Summer):

First	3 Ccf or less	\$40.00
All over	3 Ccf	3.359 ¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	\$40.00
All over	3 Ccf	4.170 ¢/Ccf

Contract Demand - \$29.70 per Ccf of Contract Demand

Minimum Charge - \$40.00 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification

Proposed Rider B - Rate Schedule II

Delivery Charges (Summer):

First	3 Ccf or less	\$43.36
All over	3 Ccf	3.565 ¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	\$43.36
All over	3 Ccf	4.426 ¢/Ccf

Contract Demand - \$31.52 per Ccf of Contract Demand

Minimum Charge - \$43.36 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

Present Rider C

Delivery Charges:

First	3 Ccf or less	\$21.50
All over	3 Ccf	11.860 ¢/Ccf

Minimum Charge - \$21.50 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification

Proposed Rider C

Delivery Charges:

First	3 Ccf or less	\$26.48
All over	3 Ccf	14.505 ¢/Ccf

Minimum Charge - \$26.48 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

* Excluding the RDM Adjustment

EXHIBIT G-13

SCHEDULE 2

Billing Comparisons

ORANGE AND ROCKLAND UTILITIES, INC.

**Monthly Billing Comparison
Reflecting Proposed Rate Change**

SC1 Residential and Space Heating

<u>Monthly Use (ccf)</u>	<u>Monthly Bill @ Present Rate</u>	<u>Monthly Bill @ Proposed Rate</u>	<u>Change</u>	
			<u>Amount</u>	<u>Percent</u>
0	\$15.35	\$19.66	\$4.31	28.08%
3	19.88	24.09	4.21	21.18%
10	32.92	37.42	4.50	13.67%
25	60.85	65.98	5.13	8.43%
50	107.40	113.59	6.19	5.76%
75	153.62	160.80	7.18	4.67%
100	199.84	208.01	8.17	4.09%
150	292.29	302.43	10.14	3.47%
200	384.73	396.84	12.11	3.15%
250	477.18	491.26	14.08	2.95%
300	569.62	585.67	16.05	2.82%
350	662.07	680.09	18.02	2.72%
400	754.51	774.50	19.99	2.65%
450	846.96	868.92	21.96	2.59%
500	939.40	963.33	23.93	2.55%
700	1,309.18	1,340.99	31.81	2.43%
1000	1,863.85	1,907.49	43.64	2.34%
1500	2,788.30	2,851.64	63.34	2.27%

ORANGE AND ROCKLAND UTILITIES, INC.

**Monthly Billing Comparison
Reflecting Proposed Rate Change**

SC2 General Service

<u>Monthly Use (ccf)</u>	<u>Monthly Bill @ Present Rate</u>	<u>Monthly Bill @ Proposed Rate</u>	<u>Change</u>	
			<u>Amount</u>	<u>Percent</u>
0	\$22.05	\$28.39	\$6.34	28.75%
3	26.52	32.76	6.24	23.53%
50	111.74	117.31	5.57	4.98%
100	201.75	206.58	4.83	2.39%
200	381.78	385.12	3.34	0.87%
300	561.81	563.66	1.85	0.33%
350	651.83	652.93	1.10	0.17%
500	921.87	920.74	(1.13)	-0.12%
750	1,371.94	1,367.08	(4.86)	-0.35%
1000	1,822.01	1,813.43	(8.58)	-0.47%
2000	3,622.30	3,598.82	(23.48)	-0.65%
3000	5,422.59	5,384.20	(38.39)	-0.71%
4000	7,222.87	7,169.59	(53.28)	-0.74%
5000	9,023.16	8,954.98	(68.18)	-0.76%
7500	13,434.13	13,323.16	(110.97)	-0.83%
10000	17,845.10	17,691.34	(153.76)	-0.86%
15000	26,667.03	26,427.70	(239.33)	-0.90%
20000	35,488.96	35,164.07	(324.89)	-0.92%

ORANGE AND ROCKLAND UTILITIES, INC.

**Monthly Billing Comparison
Reflecting Proposed Rate Change**

SC6 - Firm Transportation Service - Rate Schedule I (Residential)

<u>Monthly Use (ccf)</u>	<u>Monthly Bill @ Present Rate*</u>	<u>Monthly Bill @ Proposed Rate*</u>	<u>Change</u>	
			<u>Amount</u>	<u>Percent</u>
0	\$15.35	\$19.66	\$4.31	28.08%
3	19.73	23.97	4.24	21.49%
10	32.41	37.04	4.63	14.29%
25	59.57	65.03	5.46	9.17%
50	104.85	111.68	6.83	6.51%
75	149.79	157.93	8.14	5.43%
100	194.74	204.18	9.44	4.85%
150	284.63	296.68	12.05	4.23%
200	374.52	389.18	14.66	3.91%
250	464.41	481.69	17.28	3.72%
300	554.30	574.19	19.89	3.59%
350	644.19	666.69	22.50	3.49%
400	734.08	759.19	25.11	3.42%
450	823.97	851.69	27.72	3.36%
500	913.86	944.19	30.33	3.32%
700	1,273.42	1,314.20	40.78	3.20%
1000	1,812.76	1,869.20	56.44	3.11%
1500	2,711.67	2,794.22	82.55	3.04%

* For comparison purposes, a cost of gas supply has been included in the bill amounts. The gas supply cost is equivalent, on a per unit basis, to the cost of gas supply included in SC No. 1 and 2 bills at proposed rates.

Assumes purchase of receivables.

ORANGE AND ROCKLAND UTILITIES, INC.

**Monthly Billing Comparison
Reflecting Proposed Rate Change**

SC6 - Firm Transportation Service - Rate Schedule I (Non-Residential)

Monthly Use (ccf)	Monthly Bill @ Present Rate*	Monthly Bill @ Proposed Rate*	Change	
			Amount	Percent
0	\$22.05	\$28.39	\$6.34	28.75%
3	26.43	32.70	6.27	23.72%
50	110.25	116.39	6.14	5.57%
100	198.76	204.74	5.98	3.01%
200	375.80	381.43	5.63	1.50%
300	552.84	558.12	5.28	0.96%
350	641.36	646.47	5.11	0.80%
500	906.92	911.51	4.59	0.51%
750	1,349.52	1,353.24	3.72	0.28%
1000	1,792.11	1,794.98	2.87	0.16%
2000	3,562.50	3,561.91	(0.59)	-0.02%
3000	5,332.88	5,328.84	(4.04)	-0.08%
4000	7,103.27	7,095.77	(7.50)	-0.11%
5000	8,873.66	8,862.70	(10.96)	-0.12%
7500	13,209.87	13,184.75	(25.12)	-0.19%
10000	17,546.09	17,506.79	(39.30)	-0.22%
15000	26,218.52	26,150.88	(67.64)	-0.26%
20000	34,890.95	34,794.97	(95.98)	-0.28%

* For comparison purposes, a cost of gas supply has been included in the bill amounts. The gas supply cost is equivalent, on a per unit basis, to the cost of gas supply included in SC No. 1 and 2 bills at proposed rates.

Assumes purchase of receivables.

ORANGE AND ROCKLAND UTILITIES, INC.

**Monthly Billing Comparison
Reflecting Proposed Rate Change**

SC6 - Firm Transportation Service - Rate Schedule II

<u>Monthly Use (ccf)</u>	<u>Monthly Bill @ Present Rate*</u>	<u>Monthly Bill @ Proposed Rate*</u>	<u>Change</u>	
			<u>Amount</u>	<u>Percent</u>
1000	\$1,880.44	\$1,907.70	\$27.26	1.45%
2000	3,614.92	3,636.52	21.60	0.60%
3000	5,349.41	5,365.34	15.93	0.30%
4000	7,083.90	7,094.16	10.26	0.14%
5000	8,818.38	8,822.98	4.60	0.05%
7500	13,154.60	13,145.02	(9.58)	-0.07%
10000	17,490.81	17,467.06	(23.75)	-0.14%
15000	26,163.24	26,111.16	(52.08)	-0.20%
20000	34,835.67	34,755.25	(80.42)	-0.23%
25000	43,508.10	43,399.34	(108.76)	-0.25%
30000	52,180.53	52,043.43	(137.10)	-0.26%
35000	60,852.96	60,687.52	(165.44)	-0.27%
40000	69,525.39	69,331.60	(193.79)	-0.28%
45000	78,197.82	77,975.70	(222.12)	-0.28%
50000	86,870.25	86,619.79	(250.46)	-0.29%

* For comparison purposes, a cost of gas supply has been included in the bill amounts. The gas supply cost is equivalent, on a per unit basis, to the cost of gas supply included in SC No. 1 and 2 bills at proposed rates.

Assumes purchase of receivables.

ORANGE AND ROCKLAND UTILITIES, INC.

**Bill Comparison for a Residential
Heating Customer
Reflecting Proposed Rate Change**

<u>Month</u>	<u>Usage (Ccf)</u>	<u>Bill at Present Rates</u>	<u>Bill at Proposed Rates</u>	<u>Increase</u>	<u>Percent Increase</u>
Jan	215	\$412.47	\$425.17	\$12.70	3.08%
Feb	246	469.78	483.70	13.92	2.96%
Mar	193	371.79	383.62	11.83	3.18%
Apr	133	260.86	270.32	9.47	3.63%
May	80	162.87	170.24	7.38	4.53%
Jun	51	109.25	115.48	6.23	5.71%
Jul	44	96.23	102.17	5.94	6.17%
Aug	37	83.19	88.84	5.64	6.78%
Sep	37	83.19	88.84	5.64	6.78%
Oct	44	96.23	102.17	5.94	6.17%
Nov	91	183.20	191.02	7.81	4.26%
Dec	<u>169</u>	<u>327.42</u>	<u>338.30</u>	<u>10.89</u>	3.32%
Total	<u>1,340</u>	<u>\$2,656.48</u>	<u>\$2,759.87</u>	<u>\$103.39</u>	<u>3.89%</u>
Average	112	\$221.37	\$229.99	\$8.62	3.89%

EXHIBIT G-14

**EMBEDDED COST-OF-SERVICE STUDY AND UNBUNDLED COST
COMPONENTS**

**EXHIBIT G-14
SCHEDULE 1**

ORANGE AND ROCKLAND UTILITIES, INC.

**COST OF SERVICE STUDY - GAS DEPARTMENT
YEAR 2007
RATES IN EFFECT
NOVEMBER 1, 2008**

EXPLANATION OF DATA SOURCES AND COSTING METHODS

TABLE OF CONTENTS

<u>SECTION</u>		<u>PAGE</u>
I	Summary	3
II	Description of Operating Functions	4
III	Description of Allocation Factors in Table 7	8
IV	Description of Customer Classes	12
V	Rate of Return By Customer Class & Surplus/Deficiency – Table 1	12
VI	Total Rate Base - Table 2	14
VII	Total Operating Expenses - Table 3	18
VIII	Total Operating Revenues - Table 4	25
IX	State and Federal Income Taxes - Table 5	25
X	Customer Costs By Class - Table 6	27

ORANGE AND ROCKLAND UTILITIES, INC.
EMBEDDED COST OF SERVICE STUDY
GAS DEPARTMENT
YEAR 2007

I – SUMMARY

This Embedded Cost of Service (ECOS) study allocates Orange and Rockland Utilities, Inc. Gas Department costs among service classifications (SC's) 1 and 2, 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**. Along with the traditional functions, the study also includes fully unbundled competitive functions, i.e., the merchant function and billing and payment processing. 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 costs allocated in this study were adjusted for the following items: (1) the revenues reflect current rates, i.e., rates effective November 1, 2008. This adjustment is needed to ensure that the study reflects current rate levels and shows the correct relationship among the service classifications; (2) revenues have been reduced to exclude the Gas Supply Charge (GSC), the Monthly Gas Adjustments (MGA), and the

uncollectible component of the merchant function charge (“MFC”). The corresponding gas expenses have also been excluded; (3) interruptible customers are not represented in the study; (4) firm transportation customers have been priced as sales customers; and (5) for purposes of unbundling, the priced out revenues were used to allocate customer-care related expenses, i.e., credit & collection to competitive functions as determined by the Public Service Commission and explained further.

II - DESCRIPTION OF OPERATING FUNCTIONS:

The operating functions shown on **Table 2, Rate Base, Table 3, Operating Expenses, and Table 5, Income Taxes** (State and Federal) as described below. Where applicable, these functions include fixed costs including an allocation of common plant, associated operating expenses, administrative & general expenses (A&G), state income taxes (SIT) and federal income tax (FIT).

Lines 1--3, The Gas Supply Function

The Gas Supply Function is divided into the following three sub-functions:

Line 1, Gas Supply-Demand

Gas Supply-Demand consists of the demand costs of peaking and storage plus the demand charges relating to the storing and transporting of firm gas by the pipeline companies. All costs for this function and corresponding revenues have been excluded from this study.

Line 2, Gas Supply-Purchased Gas Cost

Gas Supply-Purchased Gas Cost represents the commodity cost of gas purchased.

All costs for this function and corresponding revenues have been excluded from this study.

Line 3, Gas Supply-Other

Gas Supply-Other consists of the costs for the Gas Control Center, recovered through rates.

Line 4, Merchant Function

The Merchant function includes the costs associated with gas purchasing & portfolio planning, hedging & market analysis, transportation services and accounting & contract administration. Also included is a revenue based allocation of credit & collection, theft, IR and education & promotional advertising. This function is allocated to classes based on a hybrid allocator, which includes procurement costs being allocated 100% on annual sales, while the revenue based adders of credit & collection, IR and education & promotional advertising are allocated 25% on annual sales and 75% on number of customers.

Line 5, Storage

Storage includes all Orange & Rockland storage expenses.

Line 6, Transmission

Transmission mains were refunctionalized to distribution mains. Therefore, there are no transmission related costs identified in this study.

Lines 7-11, Distribution

The distribution function is divided into the following five sub-functions:

Line 7, Distribution Demand ("Demand Component")

The Distribution Demand ("Demand Component") consists of the balance of the distribution mains system not allocated to the customer component, and represents fixed costs related primarily to mains. It also includes distribution pressure governors and regulating equipment, used in distributing gas from the sellers to the firm classes of services. These costs are allocated to the firm classes in proportion to their maximum one-hour non-coincident use on a zero degree day.

Line 8, Distribution Customer (“Customer Component”)

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 a study of the length of mains per service connection and the number of services for each class.

Line 9, Services

Services, consisting of the fixed costs of connecting the firm customers to the distribution system, are considered to be customer-related costs and have been apportioned, by class, based on the class allocation of the book cost of services. This allocation was based on a sample of Con Edison service costs from customers selected on the basis of end-use characteristics of Orange & Rockland’s firm service classes.

Line 10, 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. The book cost was based on a detailed study of customers’ meters for the Orange & Rockland’s gas firm service classifications.

Line 11, Customer Installation Expenses

Customer Installation Expenses consist of the costs of investigating gas leaks, shutting off defective appliances and inspecting and maintaining installations. These costs have been apportioned among classes on the basis of the total number of meters in service.

Line 12, Customer Accounting

The Customer Accounting function consists of direct customer costs for meter reading and customer records and collection expenses including other applicable operating expenses, A&G expenses, common plant, payroll taxes, state and federal income taxes. The function was reduced for the costs associated with the Receipts Processing and Printing & Mailing a Bill activity, as these costs were assigned directly to their respective functions. Also, costs related to the credit & collection function were reallocated to competitive functions based on a revenue allocation. The remaining costs were assigned to customer classes based on a composite allocation factor consisting of meter reading expenses and customer records and collection expenses.

Line 13, Receipts Processing

The Receipts Processing function consists of the customer accounting expense of accepting customer payments including both direct costs and an allocation for call center and service center operations based on a detailed study of those activities. Receipts Processing, a direct customer cost, includes an allocation of other operating expense, A&G expenses, common plant and state and federal income taxes.

Line 14, Printing & Mailing a Bill

The Printing & Mailing a Bill function consists of the customer accounting expense of billing customers, including both direct costs and an allocation for call center and service center operations based on a detailed study of those activities. Printing & Mailing a Bill, a direct customer cost, includes an allocation of other operating expenses, A&G expenses, common plant, and state and federal income taxes.

Line 15, Uncollectibles

The Uncollectibles function includes the operation and maintenance expenses for uncollectibles accounts. It was reduced to take out the commodity portion of uncollectibles recovered in the Merchant Function Charge. The Uncollectibles are allocated to the firm classes to reflect the comparative relationship between the SC No. 1 uncollectibles rate (0.51%) and the SC No. 2 uncollectibles rate (0.08%). A portion of uncollectibles was allocated on a revenue basis to competitive functions. The remaining uncollectible costs are shown on Line 15.

Line 16, Customer Service

Customer Service consists of customer assistance expenses, informational advertising expenses and sales promotion expenses. Also, costs related to educational customer advertising function were allocated to competitive functions based on a revenue allocation. The remaining costs were allocated to the customer classes based on the number of customers.

Line 17, Revenues

The Revenue function is non-applicable for this study.

III - DESCRIPTION OF ALLOCATION FACTORS IN TABLE 7

<u>Factor</u>	<u>Line No.</u>	<u>Description and Source</u>
D01	2	<u>Maximum Demand 24-Hour Use</u> - Maximum Demand 24-Hour Use on a zero degree-day, by class, from the class demand analysis. Used to allocate Gas Supply – Demand Component and Storage costs.

D02	5	<u>Maximum Demand 1-Hour Non-Coincident</u> - Maximum Demand 1- Hour Non-Coincident on a zero degree day, by class, for allocation of Distribution Demand Component costs.
E01	8	<u>Annual Gas Sales to Customers</u> - Total Annual Gas sales by class are used to allocate the Gas Supply – Purchased Gas Cost, and Gas Supply – Other.
C01	11	<u>Customer Footage of Mains</u> - Customer footage of mains is used to allocate the Distribution Customer Component.
C02	14	<u>Book Cost – Services</u> - Year-end book cost of connecting firm customers to the distribution system. This allocation was based on a sample of Con Edison service costs from customers selected on the basis of end-use characteristics of Orange and Rockland’s firm service classes.
C03	17	<u>Book Cost of Meters</u> - Year-end book cost of meters, regulators and installations used to measure customers’ usage of gas. The book cost was based on a detailed study of customers’ meters from the Orange & Rockland’s gas firm service classification.
C04	20	<u>Customer Accounting Exp</u> - The C04, Customer Accounting Exp., allocation factor was developed by allocating the PSC accounts that comprise the total customer accounting expenses, excluding receipts processing and printing & mailing a bill. The allocation factor consists of

PSC Account 902, Meter Reading allocated to the service classes based on the number of meters, PSC Account 903, Customer Records allocated based on the number of customers, PSC Account 901, Supervision and PSC Account 905, Miscellaneous allocated based on the sum of allocations of PSC Account 902 and PSC Account 903.

C05	23	<u>Uncollectible Accounts</u> - Total uncollectible accounts expenses.
C06	29	<u>Receipts Processing</u> - The Receipts Processing allocation factor represents annual receipts processing expenses allocated to classes based on the number of bills.
C07	32	<u>Printing & Mailing a Bill</u> - The Printing & Mailing a Bill allocation factor represents annual printing and mailing expenses allocated to classes based on the number of bills.
C08	26	<u>Customer Service Expense</u> - Total customer service expenses, based on number of customers by class.
CIL	35	<u>Customer Installation Expense (CIL)</u> - Total customer installations expenses, allocation based on the total number of meters.
R01	38	<u>Revenues</u> - The revenues reflect current rates, i.e., rates effective November 01, 2008 excluding the Gas Supply Charge (GSC) and the Monthly Gas Adjustments (MGA). These revenues and the 2007 sales have been recalculated as

if interruptible customers never existed and the firm transportation customers have been priced as sales customers.

R02 41

Competitive Revenues - The Competitive Revenues allocation factor represents by-class revenues for the Merchant Function Charge revenues associated with commodity procurement and credit and collections, as well as Billing and Payment Processing revenues. The revenues associated with the uncollectible component of the Merchant Function Charge have been excluded from the study.

R03 44

Net Miscellaneous Revenues - The Net Miscellaneous Revenues, allocation factor is comprised of miscellaneous revenue items allocated to the revenue function. Where applicable, these items were reduced to exclude gross receipts taxes.

U01 47

Unbundled Allocator - The Unbundled Allocator is used to allocate the unbundled merchant function. It is composed of procurement costs (allocated to service classes based on annual gas sales) and commodity-related credit & collection, information resources and education & promotional advertising costs (all allocated to classes based on 25% sales/75% customers).

K09 52

Number of Customers - Number of customers for year 2007.

IV - DESCRIPTION OF CUSTOMER CLASSES:

The customer classes consist of:

S.C. No. 1 - Residential & Space Heating - firm customers, including space heating, supplied to individual homes, apartments or other dwelling units. This class also consists of commercial customers with limited space heating.

S.C. No. 2 - General Service - applicable to use of non-residential firm gas for 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 9 Total Rate Base; Table 3, Pages 1 through 5, Total Operating Expenses; Table 4, Page 1, Operating Revenues; and Table 5, Pages 1 through 4, Income Taxes** (State and 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 5.**

Line 4, Operation and Maintenance

Total Operation and Maintenance Expenses are from **Table 3, Page 1, Line 24.**

Line 5, Depreciation and Amortization

Total Depreciation and Amortization are from **Table 3, Page 2, Line 24.**

Line 6, Property Taxes

Total Property Taxes are from **Table 3, Page 3, Line 24.**

Line 7, Payroll & Miscellaneous Taxes

Total Payroll & Miscellaneous Taxes is from **Table 3, Page 4, Line 24.**

Line 8, State Income Tax

Total State Income Taxes are from **Table 5, Page 2, Line 24.**

Line 9, Federal Income Tax

Total Federal Income Taxes are from **Table 5, Page 4, Line 24.**

Line 11, Total Operating Expenses

Total Operating Expenses is the sum of **Lines 4 through 9.**

Line 13, Utility Operating Income

Total Utility Operating Income is Total Revenues on **Line 1** less Total Operating Expenses on **Line 11.**

Line 15, Utility Rate Base

Total Utility Rate Base is from **Table 2, Page 9, Line 24.**

Line 17, Rate of Return

The Rate of Return on Utility Rate Base shown on **Line 17** is calculated by dividing Utility Operating Income on **Line 13** by Utility Rate Base on **Line 15.**

Line 19, Index

The Relative Rate of Return (index), **Line 19**, the Index, is the ratio of the class return to the system return of 6.38%.

Line 21, 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 23 and 24, Tolerance Bands

A $\pm 10\%$ tolerance band has been computed around the system rate of return, and appears on **Lines 23 and 24**, respectively.

Lines 26 and 27, Revenue Surplus and Deficiency

The revenue surplus or deficiency for the returns that fall outside of the tolerance band is shown on **Lines 26 and 27**, respectively.

VI - TOTAL RATE BASE - TABLE 2 - PAGES 1 - 9

Rate Base is shown on **Table 2, Pages 1-9**. The **Total Rate Base** shown on **Table 2, Page 9** is the sum of Production (Storage), Transmission, Distribution, Intangible, Common, General Plant and Future Use 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, Distribution, Common, General, Intangible Plant and Future Use Book Cost of Plant

The total O&R gas book costs are shown by function in **Table 2, Pages 1, Production (Storage), Transmission and Distribution Plant; Table 2, Pages 2, Future Use of Plant and Table 2, Pages 3, Intangible, Common and General Plant**. These costs are comprised of the functionalized book costs.

Description of Book Cost Functionalization from workpaper Summary Book Cost of Plant O&R Gas ECOS Study Year 2007

PSC Accounts 304, 305 and 311 Production Plant (Manufactured Gas)

The total costs for PSC Account 304, 305 and 311 that represent the book cost for liquefaction equipment were functionalized to the gas storage function.

Total Production and Storage Plant

Total Production and Storage Plant is equal to the sum of PSC Accounts 304, 305 and 311.

PSC Account 367 Mains, Transmission Plant

These costs were reclassified into the Distribution Plant – PSC Account 376 Mains.

Distribution Plant:

PSC Account 374, Land and Land Rights

These costs were functionalized directly to the Distribution Demand (“Demand Component”) function.

PSC Account 375, Structures and Improvements

These costs were functionalized directly to the Distribution Demand (“Demand Component”) function.

PSC 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 O&R Gas Mains.

PSC Account 377, Compressor Station Equipment

These costs were functionalized directly to the Distribution Demand (“Demand Component”) function.

PSC Account 378, Measuring and Regulating Equipment

These costs were functionalized directly to the Distribution Demand (“Demand Component”) function.

PSC Account 380, Services

The total book cost of Services was directly assigned to the services functions based on the Company’s property records data.

PSC 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 and Industrial Measuring and Regulating Station Equipment was functionalized direct to the Meters and House Regulators function.

PSC Account 385 Industrial Measuring and Regulating Station Equipment

The total book cost of Industrial Measuring and Regulating Station Equipment was functionalized directly to the Distribution Demand ("Demand Component") function.

PSC Account 386, Installations on Customers' Premises

The total book cost for installations on customer premises was assigned directly to the Customer Installation function.

Total Distribution Plant

Total Distribution Plant is equal to the sum of PSC Accounts 374 through 386.

Total Plant

The Total Plant equals the sum of Total Production Plant, Total Transmission Plant, and Total Distribution Plant.

PSC Accounts 301 to 303 Intangible Plant and 389 to 398, Common and General Plant

The cost of Intangible, Common and General Plants was functionalized to the functions based on labor expenses. Distribution portion of Intangible, Common and General Plant was functionalized on Distribution O&M expenses excluding rents.

Total Intangible, Common and General Plant

Total Intangible, Common and General Plant are equal to the sum of PSC Accounts 301 through 303 and PSC Accounts 389 through 398.

Future Use of Plant – Land and Land Rights

This line represents the functionalization of book cost of plant held for future use. It was functionalized based on the book cost of PSC Account 374 to the Distribution Demand (“Demand Component”).

Total Book Cost (Gross Plant)

Total Book Cost equals the sum of Total Plant, General and Intangible Plant and Total Plant for Future Use. This total represents the total gross plant by function.

Depreciation Reserve – Table 2, Page 4

The total Depreciation Reserve or Accumulated Reserve for Depreciation is shown on **Line 24** of **Table 2, Page 4**. This amount was functionalized based on the total book cost of plant.

Non-Interest-Bearing-Construction-Work-In-Progress (NIB-CWIP) - Table 2, Page 5

The average cost of NIB-CWIP monthly balances on which interest was not capitalized, is shown in total on **Line 24 of Page 5** in **Column (1) of Table 2**. This amount was functionalized based on the book cost of plant, shown on **Table 2, Pages 1-3**.

Net Plant- Table 2, Page 6

Net Plant shown on **Table 2, Page 6** by function by class is the sum of **Table 2, Pages 1-3, Plant in Service, Plant Held for Future Use and Common Plant**, less **Table 2, Page 4, Reserve for Depreciation**, plus **Table 2, Page 5, Non-Interest Bearing Construction Work In Progress**.

Total Rate Base Adjustments - Table 2, Page 7

The functional year end balances of Rate Base Adjustments are shown in total on **Line 24 of Table 2, Page 7.**

Working Capital - Table 2, Page 8

The working capital component of Rate Base is shown on **Table 2, Page 8.** It is developed from the cost of materials and supplies on hand, prepayments of operating taxes, insurance, rents, etc., 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 assigned in part to the storage function, as well as allocated to all functions based on the common/intangible/general plant book cost of plant allocations. Prepayments were apportioned to the functions based on individual cost causation. 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. Finally, a credit adjustment for Excess Rate Base Capitalization is functionalized on the subtotal rate base and added to gross working capital, resulting in the Working Capital shown on **Table 2, Page 8, Line 24.**

Total Rate Base - Table 2, Page 9

The sum of the **Net Plant, Page 6, Rate Base Adjustments, Page 7, and Working Capital, Page 8,** comprises the **Total Rate Base,** and is shown on **Page 9 of Table 2.**

VII - TABLE 3 OPERATING EXPENSES

Operating Expenses are shown on **Table 3, Pages 1-5. Total Operating Expenses** are the sum of **Total Operation and Maintenance Expenses** consisting of Gas Supply, Storage, Transmission,

Distribution, Customer Accounting, Uncollectibles and Customer Service including Miscellaneous Revenue Credits and Administrative and General Expenses plus **Total Other Expenses** (Depreciation Expenses, Property Taxes 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 PSC Account. These PSC Account costs are transferred to the Operation and Maintenance Expense workpaper including adjustments, allocations for Miscellaneous Revenue Credits and Administrative and General Expenses.

PSC Accounts 717-742 - Gas Supply, PSC Accounts 800 – 813 Production

Total gas supply expenses, were functionalized directly to the Gas Storage function. Total production expenses which were adjusted to exclude the cost of gas as it relates to the Gas Supply – Demand, Gas Supply – Commodity and Gas Supply – Other functions. The only remaining gas production costs relate to the Gas Control Center which were functionalized to Gas Supply – Other.

PSC Accounts 825-848.3 - Storage Expenses

There are no direct storage expenses shown in this study.

PSC Accounts 850-868.2 - Transmission Expenses

The transmission expenses in PSC 858 represent prepaid capacity to Algonquin. These expenses and associated revenues have been excluded from the study.

PSC Accounts 870-893 - Distribution Expenses

PSC Account 870, Supervision and Engineering

The Supervision and Engineering expense related to Operation was reallocated to Operation PSC Accounts 871 - 880 in the Reallocation column.

PSC Account 871, Load Dispatch

These costs were functionalized directly to the Distribution Demand Component function.

PSC 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 PSC Account 376, Mains and PSC Account 380, Services.

PSC Account 875, Measuring & Regulating Station Expenses and PSC Account 876,

Measuring & Regulating Station Expenses - Industrial

These costs were functionalized to the Distribution Demand Component function based on the book costs of PSC Account 378, Measuring and Regulating Equipment.

PSC Account 878, Meters and House Regulators

These costs were functionalized directly to the Meters and House Regulators function.

PSC Account 879, Customer Installations

These costs were functionalized direct to the Customer Installation function.

PSC Account 880, Other Expenses

These costs were functionalized to the Distribution Demand Component, Distribution Customer Component and the Services functions based on book cost for PSC Account 376, Mains and PSC Account 380, Services.

Total Distribution Operation Expense

Total Distribution Operation Expense is equal to the sum of PSC Account 870 through PSC Account 880.

PSC Account 885, Maintenance Supervision and Engineering

The Supervision and Engineering expense related to Maintenance was reallocated to Maintenance Expense PSC Accounts 886 – 893 in the Reallocation column.

PSC 886, Maintenance of Structures

Total of PSC Account 886 is zero.

PSC 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 PSC Account 376, Mains.

PSC Account 889, Maintenance of Measuring and Regulating Station Equipment and

PSC 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 PSC Account 378, Measuring and Regulating Equipment.

PSC Account 892, Maintenance of Services

These costs were functionalized to the Services function based on book cost of PSC Account 380, Services.

PSC 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 PSC Account 885 through PSC Account 893.

Total Distribution Operation and Maintenance Expenses excluding Rents

PSC Account 881, Rents

These costs were functionalized to the Distribution Demand Component, Distribution Customer Component, Services, Meters and House Regulators and Customer Installation functions based on total distribution book costs.

Total Distribution Expenses

This is the sum of Total Distribution Maintenance Expenses and Rents.

PSC Accounts 901 - 903 & 905 – Customer Accounting

Customer Accounting expenses, consisting of meter reading expenses and accounting expenses were functionalized directly to the Customer Accounting function. Costs related to billing and payment processing, which are comprised of costs within the Customer Accounting category were functionalized to the printing and mailing a bill and receipts processing respectively. Also, costs related to the credit & collection function were reallocated to competitive functions based on a revenue allocation.

PSC Account 904 – Uncollectibles

This account was reduced to exclude commodity related uncollectibles that are recovered in the MFC. The remaining expenses, excluding a portion that was allocated on revenue basis to competitive billing and payment processing, were functionalized directly to the Uncollectibles function.

PSC Accounts 907-916 – Total Customer Service

Customer Service expenses, excluding costs related to educational customer advertising that were allocated to competitive functions based on a revenue allocation, were functionalized directly to the Customer Service function.

PSC Accounts 920-932 Administrative and General Expenses

Company Labor was used as the basis of functionalization for PSC Accounts 920, 921, 922, 923, 926, 929, 930.2, 931 and 932. PSC Account 924 and 925 were functionalized based on adjusted Storage, Transmission and Distribution O&M Expenses. PSC Accounts 928 and 930.1 were functionalized based upon the adjusted O&M expenses, excluding gas supply expenses, uncollectibles and rents.

Sub – Total Adjusted O&M

This is the sum of Gas Supply and Production expenses, Total Distribution expenses, Customer Accounting, Uncollectibles, Customer Service and A&G expenses.

Sub – Total Adjusted O&M excluding Rents

Miscellaneous Revenue Credits

The functionalized Miscellaneous Revenue Credits represent the sum of PSC Account 488, Miscellaneous Service Revenues; PSC Account 493, Rent from Gas Property, PSC Account 495, Other Gas Revenues and PSC Account 496 Provision for Rate Refund.

Total Adjusted O&M

Total Adjusted O&M is the sum of Sub – Total Adjusted O&M and Miscellaneous Revenue Credits.

Other Expenses

Depreciation and Amortization Expense Table 3, Page 2

Depreciation Expenses shown on **Table 3, Page 2** were identified with each plant PSC Account or group of accounts and functionalized in proportion to the corresponding book cost of plant.

Amortizations of other items were then added resulting in Total Depreciation Expense.

Property Taxes - Table 3, Page 3

Property Taxes are shown on **Table 3, Pages 3**. Property taxes were functionalized based on total book cost of plant less meters and house regulators. The Common Plant portion of Property Taxes was functionalized on book cost of common plant.

Payroll and Miscellaneous Taxes - Table 3, Page 4

Payroll and Miscellaneous Taxes shown on **Table 3, Page 4** 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. Taxes for other state and local taxes were functionalized directly to storage as they represented taxes on the storage of gas in states outside of New York.

Total Other Expenses

Total Other Expenses is the sum of Depreciation Expenses, Property Taxes and Payroll and Miscellaneous Taxes.

Total Operating Expenses – Table 3, Page 5

The Grand Total tabulated on **Table 3, Page 5, 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 calculated by the sum of **Lines 1 through 3** as shown below.

Line 1, Revenues From Sales R R01

The revenues on **Line 1**, reflect current rates, i.e., rates effective November 1, 2008 excluding the Gas Supply Charge (GSC) and the Monthly Gas Adjustments (MGA).

Line 2, Competitive Revenues R R02

The Competitive Revenues consist of the Merchant Function Charge revenues associated with commodity procurement and credit and collections, as well as Billing and Payment Processing revenues. The revenues associated with the uncollectible component of the Merchant Function Charge have been excluded from the study.

Line 3, Net Miscellaneous Revenues R R03

The Net Miscellaneous Revenues are comprised of miscellaneous revenue items allocated to the revenue function. Where applicable, these items were reduced to exclude gross receipts taxes.

Line 5, Total Operating Revenues

Total Operating Revenues shown on **Line 5, Table 4** is the sum of **Lines 1 through 3**.

IX – STATE AND FEDERAL INCOME TAXES – Table 5, Pages 1 through 4

State Income Taxes are shown on **Table 5, Pages 1 and 2**. The **State Income Tax Computation** shown on **Table 5, Page 2** was calculated at 7.10% of taxable income plus **SIT Adjustments, Table 5, Page 1**. Federal Income Taxes are shown on **Table 5, Pages 3 and 4**. The **Federal Income Tax Computation** shown on **Table 5, Page 4** was calculated at 35% of taxable income (less SIT) plus **FIT Adjustments, Table 5, Page 3**. SIT and FIT amounts by function are not the

final amounts because they do not include the revenue functional amounts since they are not determined until subsequent calculations. Results are presented on a functional basis to maintain a consistent report format. The total state income tax by class is shown on **Line 24 of Table 5, Page 2** and the total federal income tax by class is shown on **Line 24 of Table 5, Page 4**.

State and Federal Income Tax Adjustments – SIT Table 5, Page 1 and FIT Table 5, Page 3

State Income Tax Adjustments shown on **Table 5, Page 1 (work paper Development of Total SIT Adjustments)** and Federal Income Tax Adjustments shown on **Table 5, Page 3 (work paper Development of Total FIT Adjustments)** 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 individuals cost causation (for functionalization purposes) are identified. Each individual deduction item is multiplied by (7.10% for SIT and 35% for FIT) and the resulting sign is reversed.

Second - Additions are listed and matched to their corresponding tax deduction. The resulting individual deductions (after 7.10% for SIT and 35% for FIT) 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 $\pm \$1000$ 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 SIT Adjustment by function, shown in **Table 5, Page 1 (work paper Functionalization of Total SIT Adjustments)** and a Total FIT Adjustment by function, shown in **Table 5, Page 3 (work paper Functionalization of Total FIT Adjustments)**.

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 **K09**.

Line 3, Rate Base

The customer related rate base shown for each class from **Table 2, Page 9, Line 22**.

Line 5, Total Customer Operating Exps.

The customer related operating expenses shown from **Table 3, Page 5, Line 22**.

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 @ 6.38% (Customer)

The applied rate of return on rate base of 6.38% is the Total System Rate of Return developed in this study, shown on **Table 1, Page 1, Column 1, Line 17**.

Line 9, S.I.T. / F.I.T. Percent on Return

The S.I.T. & F.I.T. Percent on Return, **Line 9** developed by dividing the sum of the Total Company State and Federal Income Taxes as shown on **Table 1, Page 1, Column 1, Lines 8 and 9**, respectively, by the Total System Utility Operating Income (return) shown on **Table 1, Column 1, Line 13**.

Line 10, Income Tax On Return

The Return of **Line 8** multiplied by the S.I.T. & 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 & S.I.T. / F.I.T.

The Total Return & S.I.T. / 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. S.I.T. / 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)	RESIDENTIAL & SPACE HTG SC NO. 1 (2)	GENERAL SERVICE SC NO. 2 (3)
RATE OF RETURN STATEMENT			
1 TOTAL OPERATING REVENUES	90,635,665	73,080,107	17,555,558
2			
3 OPERATING EXPENSES			
4 OPERATION & MAINTENANCE	48,952,793	44,083,187	4,869,607
5 DEPRECIATION	10,631,636	9,432,130	1,199,506
6 PROPERTY TAXES	8,060,235	7,133,835	926,400
7 PAYROLL & MISC. TAXES	972,857	866,100	106,757
8 STATE INCOME TAX	998,254	321,939	676,315
9 FEDERAL INCOME TAX	3,874,450	850,272	3,024,178
10			
11 TOTAL OPERATING EXPENSES	73,490,226	62,687,462	10,802,764
12			
13 UTILITY OPERATING INCOME	17,145,439	10,392,645	6,752,793
14			
15 UTILITY RATE BASE	268,603,749	237,243,128	31,360,622
16			
17 RATE OF RETURN (%)	6.38%	4.38%	21.53%
18			
19 INDEX	1.00	0.69	3.37
20			
21 DEVIATION	0.00	-2.00	15.15
22			
23 TOLERANCE BAND +10%	7.02%		
24 TOLERANCE BAND -10%	5.74%		
25			
26 REVENUE SURPLUS	7,536,327	0	7,536,327
27 REVENUE DEFICIENCY	5,359,986	5,359,986	0
	=====	=====	=====

				TOTAL GAS SYSTEM (1)	RESIDENTIAL & SPACE HTG SC NO. 1 (2)	GENERAL SERVICE SC NO. 2 (3)
PLANT IN SERVICE						
1	GAS SUPPLY - DEMAND	D	D01	0	0	0
2	GAS SUPPLY - PURCH. GAS COST	E	E01	0	0	0
3	GAS SUPPLY - OTHER	E	E01	0	0	0
4	MERCHANT FUNCTION	E	U01	0	0	0
5	STORAGE	D	D01	1,823,465	1,364,265	459,200
6	TRANSMISSION	D	D01	0	0	0
7	DISTRIBUTION - DEMAND	D	D02	87,338,951	69,271,660	18,067,291
8	DISTRIBUTION - CUSTOMER	C	C01	127,209,786	121,340,002	5,869,784
9	SERVICES	C	C02	130,618,371	121,083,930	9,534,441
10	METERS & HOUSE REGULATORS	C	C03	42,387,457	31,238,244	11,149,213
11	CUSTOMER INSTALLATION	C	CIL	265,003	250,149	14,854
12	CUSTOMER ACCOUNTING	C	C04	0	0	0
13	RECEIPTS PROCESSING	C	C06	0	0	0
14	PRINTING & MAILING A BILL	C	C07	0	0	0
15	UNCOLLECTIBLES	C	C05	0	0	0
16	CUSTOMER SERVICE	C	C08	0	0	0
17	REVENUES	R	R99	0	0	0
18						
19	TOTAL REVENUE	R		0	0	0
20	TOTAL DEMAND	D		89,162,416	70,635,926	18,526,490
21	TOTAL COMMODITY	E		0	0	0
22	TOTAL CUSTOMER	C		300,480,617	273,912,326	26,568,291
23						
24	TOTAL			389,643,033	344,548,251	45,094,782
				=====	=====	=====

				TOTAL GAS SYSTEM (1)	RESIDENTIAL & SPACE HTG SC NO. 1 (2)	GENERAL SERVICE SC NO. 2 (3)
PLANT HELD FOR FUTURE USE						
1	GAS SUPPLY - DEMAND	D	D01	0	0	0
2	GAS SUPPLY - PURCH. GAS COST	E	E01	0	0	0
3	GAS SUPPLY - OTHER	E	E01	0	0	0
4	MERCHANT FUNCTION	E	U01	0	0	0
5	STORAGE	D	D01	0	0	0
6	TRANSMISSION	D	D01	0	0	0
7	DISTRIBUTION - DEMAND	D	D02	71,414	56,641	14,773
8	DISTRIBUTION - CUSTOMER	C	C01	138,921	132,511	6,410
9	SERVICES	C	C02	0	0	0
10	METERS & HOUSE REGULATORS	C	C03	0	0	0
11	CUSTOMER INSTALLATION	C	CIL	0	0	0
12	CUSTOMER ACCOUNTING	C	C04	0	0	0
13	RECEIPTS PROCESSING	C	C06	0	0	0
14	PRINTING & MAILING A BILL	C	C07	0	0	0
15	UNCOLLECTIBLES	C	C05	0	0	0
16	CUSTOMER SERVICE	C	C08	0	0	0
17	REVENUES	R	R99	0	0	0
18						
19	TOTAL REVENUE	R		0	0	0
20	TOTAL DEMAND	D		71,414	56,641	14,773
21	TOTAL COMMODITY	E		0	0	0
22	TOTAL CUSTOMER	C		138,921	132,511	6,410
23						
24	TOTAL			210,335	189,152	21,183
				=====	=====	=====

				TOTAL GAS SYSTEM (1)	RESIDENTIAL & SPACE HTG SC NO. 1 (2)	GENERAL SERVICE SC NO. 2 (3)
COMMON PLANT						
1	GAS SUPPLY - DEMAND	D	D01	0	0	0
2	GAS SUPPLY - PURCH. GAS COST	E	E01	0	0	0
3	GAS SUPPLY - OTHER	E	E01	584,142	429,829	154,313
4	MERCHANT FUNCTION	E	U01	1,022,646	976,742	45,904
5	STORAGE	D	D01	231,091	172,896	58,195
6	TRANSMISSION	D	D01	0	0	0
7	DISTRIBUTION - DEMAND	D	D02	10,465,405	8,300,489	2,164,916
8	DISTRIBUTION - CUSTOMER	C	C01	10,038,052	9,574,871	463,181
9	SERVICES	C	C02	8,352,454	7,742,770	609,684
10	METERS & HOUSE REGULATORS	C	C03	2,591,726	1,910,022	681,704
11	CUSTOMER INSTALLATION	C	CIL	6,694,474	6,319,245	375,229
12	CUSTOMER ACCOUNTING	C	C04	5,532,643	5,229,146	303,497
13	RECEIPTS PROCESSING	C	C06	406,367	384,267	22,100
14	PRINTING & MAILING A BILL	C	C07	99,088	93,699	5,389
15	UNCOLLECTIBLES	C	C05	0	0	0
16	CUSTOMER SERVICE	C	C08	1,497,965	1,416,497	81,468
17	REVENUES	R	R99	0	0	0
18						
19	TOTAL REVENUE	R		0	0	0
20	TOTAL DEMAND	D		10,696,496	8,473,385	2,223,111
21	TOTAL COMMODITY	E		1,606,788	1,406,571	200,217
22	TOTAL CUSTOMER	C		35,212,769	32,670,517	2,542,252
23						
24	TOTAL			47,516,053	42,550,472	4,965,581
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				TOTAL GAS SYSTEM (1)	RESIDENTIAL & SPACE HTG SC NO. 1 (2)	GENERAL SERVICE SC NO. 2 (3)
DEPRECIATION RESERVE						
1	GAS SUPPLY - DEMAND	D	D01	0	0	0
2	GAS SUPPLY - PURCH. GAS COST	E	E01	0	0	0
3	GAS SUPPLY - OTHER	E	E01	253,177	186,295	66,882
4	MERCHANT FUNCTION	E	U01	443,244	423,348	19,896
5	STORAGE	D	D01	(387,105)	(289,621)	(97,484)
6	TRANSMISSION	D	D01	0	0	0
7	DISTRIBUTION - DEMAND	D	D02	30,667,837	24,323,763	6,344,074
8	DISTRIBUTION - CUSTOMER	C	C01	38,663,686	36,879,645	1,784,041
9	SERVICES	C	C02	52,611,410	48,771,059	3,840,351
10	METERS & HOUSE REGULATORS	C	C03	11,861,552	8,741,597	3,119,955
11	CUSTOMER INSTALLATION	C	CIL	3,034,426	2,864,345	170,081
12	CUSTOMER ACCOUNTING	C	C04	2,398,003	2,266,459	131,544
13	RECEIPTS PROCESSING	C	C06	176,132	166,553	9,579
14	PRINTING & MAILING A BILL	C	C07	42,949	40,613	2,336
15	UNCOLLECTIBLES	C	C05	0	0	0
16	CUSTOMER SERVICE	C	C08	649,260	613,950	35,310
17	REVENUES	R	R99	0	0	0
18						
19	TOTAL REVENUE	R		0	0	0
20	TOTAL DEMAND	D		30,280,732	24,034,142	6,246,590
21	TOTAL COMMODITY	E		696,421	609,643	86,778
22	TOTAL CUSTOMER	C		109,437,418	100,344,220	9,093,198
23						
24	TOTAL			140,414,571	124,988,006	15,426,565
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				TOTAL GAS SYSTEM (1)	RESIDENTIAL & SPACE HTG SC NO. 1 (2)	GENERAL SERVICE SC NO. 2 (3)
NON-INTEREST BEARING CWIP						
1	GAS SUPPLY - DEMAND	D	D01	0	0	0
2	GAS SUPPLY - PURCH. GAS COST	E	E01	0	0	0
3	GAS SUPPLY - OTHER	E	E01	34,974	25,735	9,239
4	MERCHANT FUNCTION	E	U01	61,230	58,482	2,748
5	STORAGE	D	D01	34,149	25,549	8,600
6	TRANSMISSION	D	D01	0	0	0
7	DISTRIBUTION - DEMAND	D	D02	1,600,344	1,269,291	331,054
8	DISTRIBUTION - CUSTOMER	C	C01	2,019,661	1,926,469	93,192
9	SERVICES	C	C02	1,955,161	1,812,445	142,716
10	METERS & HOUSE REGULATORS	C	C03	627,366	462,349	165,017
11	CUSTOMER INSTALLATION	C	CIL	403,780	381,148	22,632
12	CUSTOMER ACCOUNTING	C	C04	331,264	313,092	18,172
13	RECEIPTS PROCESSING	C	C06	24,331	23,008	1,323
14	PRINTING & MAILING A BILL	C	C07	5,933	5,610	323
15	UNCOLLECTIBLES	C	C05	0	0	0
16	CUSTOMER SERVICE	C	C08	89,690	84,812	4,878
17	REVENUES	R	R99	0	0	0
18				-----	-----	-----
19	TOTAL REVENUE	R		0	0	0
20	TOTAL DEMAND	D		1,634,493	1,294,840	339,653
21	TOTAL COMMODITY	E		96,204	84,217	11,988
22	TOTAL CUSTOMER	C		5,457,186	5,008,933	448,253
23				-----	-----	-----
24	TOTAL			7,187,883	6,387,990	799,894
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			TOTAL GAS SYSTEM (1)	RESIDENTIAL & SPACE HTG SC NO. 1 (2)	GENERAL SERVICE SC NO. 2 (3)
NET PLANT					
1	GAS SUPPLY - DEMAND	D	0	0	0
2	GAS SUPPLY - PURCH. GAS COST	E	0	0	0
3	GAS SUPPLY - OTHER	E	365,939	269,269	96,670
4	MERCHANT FUNCTION	E	640,632	611,876	28,756
5	STORAGE	D	2,475,810	1,852,332	623,478
6	TRANSMISSION	D	0	0	0
7	DISTRIBUTION - DEMAND	D	68,808,277	54,574,317	14,233,960
8	DISTRIBUTION - CUSTOMER	C	100,742,734	96,094,208	4,648,526
9	SERVICES	C	88,314,576	81,868,085	6,446,491
10	METERS & HOUSE REGULATORS	C	33,744,997	24,869,018	8,875,979
11	CUSTOMER INSTALLATION	C	4,328,831	4,086,198	242,633
12	CUSTOMER ACCOUNTING	C	3,465,904	3,275,780	190,124
13	RECEIPTS PROCESSING	C	254,566	240,722	13,844
14	PRINTING & MAILING A BILL	C	62,072	58,696	3,376
15	UNCOLLECTIBLES	C	0	0	0
16	CUSTOMER SERVICE	C	938,395	887,360	51,035
17	REVENUES	R	0	0	0
18					
19	TOTAL REVENUE	R	0	0	0
20	TOTAL DEMAND	D	71,284,087	56,426,649	14,857,439
21	TOTAL COMMODITY	E	1,006,571	881,145	125,426
22	TOTAL CUSTOMER	C	231,852,075	211,380,066	20,472,009
23					
24	TOTAL		304,142,733	268,687,859	35,454,874
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				TOTAL GAS SYSTEM (1)	RESIDENTIAL & SPACE HTG SC NO. 1 (2)	GENERAL SERVICE SC NO. 2 (3)
TOTAL RATE BASE ADJUSTMENTS						
1	GAS SUPPLY - DEMAND	D	D01	0	0	0
2	GAS SUPPLY - PURCH. GAS COST	E	E01	0	0	0
3	GAS SUPPLY - OTHER	E	E01	(117,019)	(86,106)	(30,913)
4	MERCHANT FUNCTION	E	U01	(204,860)	(195,664)	(9,196)
5	STORAGE	D	D01	(241,629)	(180,780)	(60,849)
6	TRANSMISSION	D	D01	0	0	0
7	DISTRIBUTION - DEMAND	D	D02	(11,653,524)	(9,242,829)	(2,410,695)
8	DISTRIBUTION - CUSTOMER	C	C01	(16,198,881)	(15,451,423)	(747,458)
9	SERVICES	C	C02	(16,309,403)	(15,118,904)	(1,190,499)
10	METERS & HOUSE REGULATORS	C	C03	(5,232,159)	(3,855,939)	(1,376,220)
11	CUSTOMER INSTALLATION	C	CIL	(1,373,026)	(1,296,067)	(76,959)
12	CUSTOMER ACCOUNTING	C	C04	(1,108,319)	(1,047,521)	(60,798)
13	RECEIPTS PROCESSING	C	C06	(81,404)	(76,977)	(4,427)
14	PRINTING & MAILING A BILL	C	C07	(19,849)	(18,769)	(1,080)
15	UNCOLLECTIBLES	C	C05	0	0	0
16	CUSTOMER SERVICE	C	C08	(143,077)	(135,296)	(7,781)
17	REVENUES	R	R99	0	0	0
18						
19	TOTAL REVENUE	R		0	0	0
20	TOTAL DEMAND	D		(11,895,153)	(9,423,609)	(2,471,544)
21	TOTAL COMMODITY	E		(321,879)	(281,770)	(40,109)
22	TOTAL CUSTOMER	C		(40,466,118)	(37,000,897)	(3,465,221)
23						
24	TOTAL			(52,683,150)	(46,706,276)	(5,976,874)
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				TOTAL GAS SYSTEM (1)	RESIDENTIAL & SPACE HTG SC NO. 1 (2)	GENERAL SERVICE SC NO. 2 (3)
WORKING CAPITAL						
1	GAS SUPPLY - DEMAND	D	D01	0	0	0
2	GAS SUPPLY - PURCH. GAS COST	E	E01	0	0	0
3	GAS SUPPLY - OTHER	E	E01	110,562	81,355	29,207
4	MERCHANT FUNCTION	E	U01	219,857	209,988	9,869
5	STORAGE	D	D01	117,471	87,889	29,582
6	TRANSMISSION	D	D01	0	0	0
7	DISTRIBUTION - DEMAND	D	D02	3,729,893	2,958,312	771,581
8	DISTRIBUTION - CUSTOMER	C	C01	4,617,317	4,404,262	213,055
9	SERVICES	C	C02	4,062,261	3,765,738	296,523
10	METERS & HOUSE REGULATORS	C	C03	1,424,372	1,049,718	374,654
11	CUSTOMER INSTALLATION	C	CIL	1,163,019	1,097,831	65,188
12	CUSTOMER ACCOUNTING	C	C04	1,145,603	1,082,760	62,843
13	RECEIPTS PROCESSING	C	C06	69,728	65,936	3,792
14	PRINTING & MAILING A BILL	C	C07	55,964	52,920	3,044
15	UNCOLLECTIBLES	C	C05	0	0	0
16	CUSTOMER SERVICE	C	C08	428,119	404,835	23,284
17	REVENUES	R	R99	0	0	0
18						
19	TOTAL REVENUE	R		0	0	0
20	TOTAL DEMAND	D		3,847,364	3,046,201	801,163
21	TOTAL COMMODITY	E		330,419	291,343	39,076
22	TOTAL CUSTOMER	C		12,966,383	11,924,001	1,042,382
23						
24	TOTAL			17,144,166	15,261,545	1,882,621
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			TOTAL GAS SYSTEM (1)	RESIDENTIAL & SPACE HTG SC NO. 1 (2)	GENERAL SERVICE SC NO. 2 (3)
TOTAL RATE BASE					
1	GAS SUPPLY - DEMAND	D	0	0	0
2	GAS SUPPLY - PURCH. GAS COST	E	0	0	0
3	GAS SUPPLY - OTHER	E	359,482	264,518	94,964
4	MERCHANT FUNCTION	E	655,629	626,200	29,429
5	STORAGE	D	2,351,652	1,759,440	592,212
6	TRANSMISSION	D	0	0	0
7	DISTRIBUTION - DEMAND	D	60,884,646	48,289,801	12,594,846
8	DISTRIBUTION - CUSTOMER	C	89,161,170	85,047,046	4,114,124
9	SERVICES	C	76,067,434	70,514,919	5,552,515
10	METERS & HOUSE REGULATORS	C	29,937,210	22,062,797	7,874,413
11	CUSTOMER INSTALLATION	C	4,118,824	3,887,962	230,862
12	CUSTOMER ACCOUNTING	C	3,503,188	3,311,018	192,170
13	RECEIPTS PROCESSING	C	242,890	229,681	13,209
14	PRINTING & MAILING A BILL	C	98,187	92,847	5,340
15	UNCOLLECTIBLES	C	0	0	0
16	CUSTOMER SERVICE	C	1,223,437	1,156,899	66,538
17	REVENUES	R	0	0	0
18					
19	TOTAL REVENUE	R	0	0	0
20	TOTAL DEMAND	D	63,236,298	50,049,241	13,187,058
21	TOTAL COMMODITY	E	1,015,111	890,717	124,394
22	TOTAL CUSTOMER	C	204,352,340	186,303,170	18,049,170
23					
24	TOTAL		268,603,749	237,243,128	31,360,622
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				TOTAL GAS SYSTEM (1)	RESIDENTIAL & SPACE HTG SC NO. 1 (2)	GENERAL SERVICE SC NO. 2 (3)
OPERATION & MAINTENANCE						
1	GAS SUPPLY - DEMAND	D	D01	0	0	0
2	GAS SUPPLY - PURCH. GAS COST	E	E01	0	0	0
3	GAS SUPPLY - OTHER	E	E01	660,975	486,365	174,610
4	MERCHANT FUNCTION	E	U01	1,152,598	1,100,861	51,737
5	STORAGE	D	D01	(271,717)	(203,291)	(68,426)
6	TRANSMISSION	D	D01	0	0	0
7	DISTRIBUTION - DEMAND	D	D02	10,099,786	8,010,503	2,089,283
8	DISTRIBUTION - CUSTOMER	C	C01	9,647,717	9,202,547	445,170
9	SERVICES	C	C02	8,023,505	7,437,832	585,673
10	METERS & HOUSE REGULATORS	C	C03	2,490,566	1,835,470	655,096
11	CUSTOMER INSTALLATION	C	CIL	6,495,503	6,131,426	364,077
12	CUSTOMER ACCOUNTING	C	C04	6,547,960	6,188,767	359,193
13	RECEIPTS PROCESSING	C	C06	404,250	382,265	21,985
14	PRINTING & MAILING A BILL	C	C07	403,325	381,389	21,936
15	UNCOLLECTIBLES	C	C05	638,481	613,864	24,617
16	CUSTOMER SERVICE	C	C08	2,659,847	2,515,189	144,658
17	REVENUES	R	R99	(0)	0	0
18				-----	-----	-----
19	TOTAL REVENUE	R		(0)	0	0
20	TOTAL DEMAND	D		9,828,069	7,807,212	2,020,857
21	TOTAL COMMODITY	E		1,813,573	1,587,226	226,347
22	TOTAL CUSTOMER	C		37,311,152	34,688,749	2,622,403
23				-----	-----	-----
24	TOTAL			48,952,793	44,083,187	4,869,607
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				TOTAL GAS SYSTEM (1)	RESIDENTIAL & SPACE HTG SC NO. 1 (2)	GENERAL SERVICE SC NO. 2 (3)
DEPRECIATION & AMORTIZATION						
1	GAS SUPPLY - DEMAND	D	D01	0	0	0
2	GAS SUPPLY - PURCH. GAS COST	E	E01	0	0	0
3	GAS SUPPLY - OTHER	E	E01	26,700	19,647	7,053
4	MERCHANT FUNCTION	E	U01	46,744	44,646	2,098
5	STORAGE	D	D01	78,806	58,961	19,846
6	TRANSMISSION	D	D01	0	0	0
7	DISTRIBUTION - DEMAND	D	D02	2,216,989	1,758,374	458,615
8	DISTRIBUTION - CUSTOMER	C	C01	2,611,001	2,490,523	120,478
9	SERVICES	C	C02	3,985,452	3,694,535	290,917
10	METERS & HOUSE REGULATORS	C	C03	1,002,879	739,091	263,788
11	CUSTOMER INSTALLATION	C	CIL	318,599	300,741	17,858
12	CUSTOMER ACCOUNTING	C	C04	252,890	239,018	13,872
13	RECEIPTS PROCESSING	C	C06	18,575	17,565	1,010
14	PRINTING & MAILING A BILL	C	C07	4,529	4,283	246
15	UNCOLLECTIBLES	C	C05	0	0	0
16	CUSTOMER SERVICE	C	C08	68,472	64,748	3,724
17	REVENUES	R	R99	0	0	0
18						
19	TOTAL REVENUE	R		0	0	0
20	TOTAL DEMAND	D		2,295,795	1,817,334	478,461
21	TOTAL COMMODITY	E		73,444	64,292	9,152
22	TOTAL CUSTOMER	C		8,262,397	7,550,503	711,894
23						
24	TOTAL			10,631,636	9,432,130	1,199,506
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				TOTAL GAS SYSTEM (1)	RESIDENTIAL & SPACE HTG SC NO. 1 (2)	GENERAL SERVICE SC NO. 2 (3)
PROPERTY TAXES						
1	GAS SUPPLY - DEMAND	D	D01	0	0	0
2	GAS SUPPLY - PURCH. GAS COST	E	E01	0	0	0
3	GAS SUPPLY - OTHER	E	E01	7,049	5,187	1,862
4	MERCHANT FUNCTION	E	U01	12,341	11,787	554
5	STORAGE	D	D01	37,825	28,300	9,525
6	TRANSMISSION	D	D01	0	0	0
7	DISTRIBUTION - DEMAND	D	D02	1,804,474	1,431,193	373,281
8	DISTRIBUTION - CUSTOMER	C	C01	2,565,419	2,447,044	118,375
9	SERVICES	C	C02	2,610,573	2,420,015	190,558
10	METERS & HOUSE REGULATORS	C	C03	845,734	623,280	222,454
11	CUSTOMER INSTALLATION	C	CIL	85,878	81,064	4,814
12	CUSTOMER ACCOUNTING	C	C04	66,765	63,103	3,662
13	RECEIPTS PROCESSING	C	C06	4,904	4,637	267
14	PRINTING & MAILING A BILL	C	C07	1,196	1,131	65
15	UNCOLLECTIBLES	C	C05	0	0	0
16	CUSTOMER SERVICE	C	C08	18,077	17,094	983
17	REVENUES	R	R99	0	0	0
18						
19	TOTAL REVENUE	R		0	0	0
20	TOTAL DEMAND	D		1,842,299	1,459,493	382,806
21	TOTAL COMMODITY	E		19,390	16,974	2,416
22	TOTAL CUSTOMER	C		6,198,546	5,657,368	541,178
23						
24	TOTAL			8,060,235	7,133,835	926,400
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				TOTAL GAS SYSTEM (1)	RESIDENTIAL & SPACE HTG SC NO. 1 (2)	GENERAL SERVICE SC NO. 2 (3)
PAYROLL & MISC. TAXES						
1	GAS SUPPLY - DEMAND	D	D01	0	0	0
2	GAS SUPPLY - PURCH. GAS COST	E	E01	0	0	0
3	GAS SUPPLY - OTHER	E	E01	11,525	8,480	3,045
4	MERCHANT FUNCTION	E	U01	20,182	19,276	906
5	STORAGE	D	D01	39,066	29,228	9,838
6	TRANSMISSION	D	D01	0	0	0
7	DISTRIBUTION - DEMAND	D	D02	206,678	163,924	42,754
8	DISTRIBUTION - CUSTOMER	C	C01	198,318	189,167	9,151
9	SERVICES	C	C02	165,027	152,981	12,046
10	METERS & HOUSE REGULATORS	C	C03	51,222	37,749	13,473
11	CUSTOMER INSTALLATION	C	CIL	132,114	124,709	7,405
12	CUSTOMER ACCOUNTING	C	C04	109,186	103,197	5,989
13	RECEIPTS PROCESSING	C	C06	8,022	7,586	436
14	PRINTING & MAILING A BILL	C	C07	1,955	1,849	106
15	UNCOLLECTIBLES	C	C05	0	0	0
16	CUSTOMER SERVICE	C	C08	29,562	27,954	1,608
17	REVENUES	R	R99	0	0	0
18						
19	TOTAL REVENUE	R		0	0	0
20	TOTAL DEMAND	D		245,744	193,152	52,592
21	TOTAL COMMODITY	E		31,707	27,757	3,950
22	TOTAL CUSTOMER	C		695,406	645,191	50,215
23						
24	TOTAL			972,857	866,100	106,757

			TOTAL GAS SYSTEM (1)	RESIDENTIAL & SPACE HTG SC NO. 1 (2)	GENERAL SERVICE SC NO. 2 (3)
TOTAL OPERATING EXPENSES					
1	GAS SUPPLY - DEMAND	D	0	0	0
2	GAS SUPPLY - PURCH. GAS COST	E	0	0	0
3	GAS SUPPLY - OTHER	E	706,249	519,679	186,570
4	MERCHANT FUNCTION	E	1,231,865	1,176,570	55,295
5	STORAGE	D	(116,020)	(86,803)	(29,217)
6	TRANSMISSION	D	0	0	0
7	DISTRIBUTION - DEMAND	D	14,327,927	11,363,994	2,963,933
8	DISTRIBUTION - CUSTOMER	C	15,022,455	14,329,281	693,174
9	SERVICES	C	14,784,557	13,705,364	1,079,193
10	METERS & HOUSE REGULATORS	C	4,390,401	3,235,590	1,154,811
11	CUSTOMER INSTALLATION	C	7,032,094	6,637,941	394,153
12	CUSTOMER ACCOUNTING	C	6,976,801	6,594,084	382,717
13	RECEIPTS PROCESSING	C	435,751	412,053	23,698
14	PRINTING & MAILING A BILL	C	411,005	388,651	22,353
15	UNCOLLECTIBLES	C	638,481	613,864	24,617
16	CUSTOMER SERVICE	C	2,775,958	2,624,985	150,972
17	REVENUES	R	(0)	0	0
18					
19	TOTAL REVENUE	R	(0)	0	0
20	TOTAL DEMAND	D	14,211,907	11,277,191	2,934,716
21	TOTAL COMMODITY	E	1,938,114	1,696,249	241,865
22	TOTAL CUSTOMER	C	52,467,501	48,541,812	3,925,689
23					
24	TOTAL		68,617,522	61,515,251	7,102,271
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				TOTAL GAS SYSTEM (1)	RESIDENTIAL & SPACE HTG SC NO. 1 (2)	GENERAL SERVICE SC NO. 2 (3)
OPERATING REVENUES						
1	REVENUES FROM SALES	R	R01	83,979,990	66,889,835	17,090,155
2	COMPETITIVE REVENUES	R	R02	3,039,716	2,827,162	212,554
3	MISCELLANEOUS REVENUES	R	R03	3,615,959	3,363,110	252,849
4						
5	TOTAL OPERATING REVENUES			90,635,665	73,080,107	17,555,558
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				TOTAL GAS SYSTEM (1)	RESIDENTIAL & SPACE HTG SC NO. 1 (2)	GENERAL SERVICE SC NO. 2 (3)
SIT ADJUSTMENTS						
1	GAS SUPPLY - DEMAND	D	D01	0	0	0
2	GAS SUPPLY - PURCH. GAS COST	E	E01	0	0	0
3	GAS SUPPLY - OTHER	E	E01	(680)	(500)	(180)
4	MERCHANT FUNCTION	E	U01	(1,190)	(1,137)	(53)
5	STORAGE	D	D01	(4,600)	(3,442)	(1,158)
6	TRANSMISSION	D	D01	0	0	0
7	DISTRIBUTION - DEMAND	D	D02	(127,832)	(101,388)	(26,444)
8	DISTRIBUTION - CUSTOMER	C	C01	(187,159)	(178,523)	(8,636)
9	SERVICES	C	C02	(164,070)	(152,094)	(11,976)
10	METERS & HOUSE REGULATORS	C	C03	(62,691)	(46,201)	(16,490)
11	CUSTOMER INSTALLATION	C	CIL	(8,042)	(7,591)	(451)
12	CUSTOMER ACCOUNTING	C	C04	(6,439)	(6,086)	(353)
13	RECEIPTS PROCESSING	C	C06	(473)	(447)	(26)
14	PRINTING & MAILING A BILL	C	C07	(115)	(109)	(6)
15	UNCOLLECTIBLES	C	C05	0	0	0
16	CUSTOMER SERVICE	C	C08	(1,743)	(1,648)	(95)
17	REVENUES	R	R99	0	0	0
18				-----	-----	-----
19	TOTAL REVENUE	R		0	0	0
20	TOTAL DEMAND	D		(132,432)	(104,830)	(27,602)
21	TOTAL COMMODITY	E		(1,870)	(1,637)	(233)
22	TOTAL CUSTOMER	C		(430,732)	(392,699)	(38,033)
23				-----	-----	-----
24	TOTAL			(565,034)	(499,166)	(65,868)
				=====	=====	=====

			TOTAL GAS SYSTEM (1)	RESIDENTIAL & SPACE HTG SC NO. 1 (2)	GENERAL SERVICE SC NO. 2 (3)
STATE INCOME TAX COMPUTATION					
1	GAS SUPPLY - DEMAND	D	0	0	0
2	GAS SUPPLY - PURCH. GAS COST	E	0	0	0
3	GAS SUPPLY - OTHER	E	(50,824)	(37,398)	(13,426)
4	MERCHANT FUNCTION	E	(88,652)	(84,673)	(3,979)
5	STORAGE	D	3,637	2,721	916
6	TRANSMISSION	D	0	0	0
7	DISTRIBUTION - DEMAND	D	(1,145,115)	(908,232)	(236,883)
8	DISTRIBUTION - CUSTOMER	C	(1,253,753)	(1,195,902)	(57,851)
9	SERVICES	C	(1,213,774)	(1,125,175)	(88,599)
10	METERS & HOUSE REGULATORS	C	(374,409)	(275,928)	(98,481)
11	CUSTOMER INSTALLATION	C	(507,321)	(478,885)	(28,436)
12	CUSTOMER ACCOUNTING	C	(501,792)	(474,266)	(27,526)
13	RECEIPTS PROCESSING	C	(31,411)	(29,703)	(1,708)
14	PRINTING & MAILING A BILL	C	(29,296)	(27,703)	(1,593)
15	UNCOLLECTIBLES	C	(45,332)	(43,584)	(1,748)
16	CUSTOMER SERVICE	C	(198,836)	(188,022)	(10,814)
17	REVENUES	R	6,435,132	5,188,688	1,246,445
18					
19	TOTAL REVENUE	R	6,435,132	5,188,688	1,246,445
20	TOTAL DEMAND	D	(1,141,477)	(905,510)	(235,967)
21	TOTAL COMMODITY	E	(139,476)	(122,071)	(17,405)
22	TOTAL CUSTOMER	C	(4,155,925)	(3,839,168)	(316,757)
23					
24	TOTAL		998,254	321,939	676,315
			=====	=====	=====

				TOTAL GAS SYSTEM (1)	RESIDENTIAL & SPACE HTG SC NO. 1 (2)	GENERAL SERVICE SC NO. 2 (3)
FIT ADJUSTMENTS						
1	GAS SUPPLY - DEMAND	D	D01	0	0	0
2	GAS SUPPLY - PURCH. GAS COST	E	E01	0	0	0
3	GAS SUPPLY - OTHER	E	E01	(2,817)	(2,073)	(744)
4	MERCHANT FUNCTION	E	U01	(4,923)	(4,702)	(221)
5	STORAGE	D	D01	(17,693)	(13,237)	(4,456)
6	TRANSMISSION	D	D01	0	0	0
7	DISTRIBUTION - DEMAND	D	D02	(785,972)	(623,383)	(162,589)
8	DISTRIBUTION - CUSTOMER	C	C01	(1,310,801)	(1,250,317)	(60,484)
9	SERVICES	C	C02	(918,044)	(851,032)	(67,012)
10	METERS & HOUSE REGULATORS	C	C03	(374,502)	(275,996)	(98,506)
11	CUSTOMER INSTALLATION	C	CIL	(31,475)	(29,711)	(1,764)
12	CUSTOMER ACCOUNTING	C	C04	(26,639)	(25,178)	(1,461)
13	RECEIPTS PROCESSING	C	C06	(1,957)	(1,851)	(106)
14	PRINTING & MAILING A BILL	C	C07	(477)	(451)	(26)
15	UNCOLLECTIBLES	C	C05	0	0	0
16	CUSTOMER SERVICE	C	C08	(7,211)	(6,819)	(392)
17	REVENUES	R	R99	0	0	0
18						
19	TOTAL REVENUE	R		0	0	0
20	TOTAL DEMAND	D		(803,665)	(636,620)	(167,045)
21	TOTAL COMMODITY	E		(7,740)	(6,775)	(965)
22	TOTAL CUSTOMER	C		(2,671,106)	(2,441,354)	(229,752)
23						
24	TOTAL			(3,482,511)	(3,084,749)	(397,762)
				=====	=====	=====

			TOTAL GAS SYSTEM (1)	RESIDENTIAL & SPACE HTG SC NO. 1 (2)	GENERAL SERVICE SC NO. 2 (3)
FEDERAL INCOME TAX COMPUTATION					
1	GAS SUPPLY - DEMAND	D	0	0	0
2	GAS SUPPLY - PURCH. GAS COST	E	0	0	0
3	GAS SUPPLY - OTHER	E	(232,216)	(170,871)	(61,344)
4	MERCHANT FUNCTION	E	(405,047)	(386,866)	(18,181)
5	STORAGE	D	21,641	16,191	5,450
6	TRANSMISSION	D	0	0	0
7	DISTRIBUTION - DEMAND	D	(5,399,956)	(4,282,899)	(1,117,057)
8	DISTRIBUTION - CUSTOMER	C	(6,129,847)	(5,847,000)	(282,847)
9	SERVICES	C	(5,667,818)	(5,254,098)	(413,720)
10	METERS & HOUSE REGULATORS	C	(1,780,099)	(1,311,878)	(468,221)
11	CUSTOMER INSTALLATION	C	(2,315,146)	(2,185,380)	(129,765)
12	CUSTOMER ACCOUNTING	C	(2,292,892)	(2,167,114)	(125,778)
13	RECEIPTS PROCESSING	C	(143,476)	(135,673)	(7,803)
14	PRINTING & MAILING A BILL	C	(134,075)	(126,783)	(7,292)
15	UNCOLLECTIBLES	C	(207,602)	(199,598)	(8,004)
16	CUSTOMER SERVICE	C	(909,204)	(859,756)	(49,448)
17	REVENUES	R	29,470,187	23,761,997	5,708,190
18					
19	TOTAL REVENUE	R	29,470,187	23,761,997	5,708,190
20	TOTAL DEMAND	D	(5,378,315)	(4,286,708)	(1,111,607)
21	TOTAL COMMODITY	E	(637,263)	(557,737)	(79,526)
22	TOTAL CUSTOMER	C	(19,580,158)	(18,087,280)	(1,492,878)
23					
24	TOTAL		3,874,450	850,272	3,024,178
			=====	=====	=====

	TOTAL GAS SYSTEM (1)	RESIDENTIAL & SPACE HTG SC NO. 1 (2)	GENERAL SERVICE SC NO. 2 (3)
CUSTOMER COST BY CLASS			
1 NUMBER OF CUSTOMERS	125,213	118,403	6,810
2			
3 RATE BASE	204,352,340	186,303,170	18,049,170
4			
5 TOTAL CUSTOMER OPERATING EXPS	52,467,501	48,541,812	3,925,689
6 MONTHLY OP. EXPS. COST/CUST	34.92	34.16	48.04
7			
8 RETURN @ 6.38% (CUSTOMER)	13,044,161	11,892,052	1,152,110
9 S.I.T. / F.I.T. PERCENT ON RETURN	28.42%		
10 INCOME TAX ON RETURN	3,707,128	3,379,701	327,428
11 TOTAL RETURN & S.I.T. / F.I.T.	16,751,289	15,271,752	1,479,537
12 MONTHLY RET. S.I.T. / F.I.T. COST/CU	11.15	10.75	18.11
13			
14 MONTHLY CUSTOMER COSTS	46.07	44.91	66.14
	=====	=====	=====

			TOTAL GAS SYSTEM (1)	RESIDENTIAL & SPACE HTG SC NO. 1 (2)	GENERAL SERVICE SC NO. 2 (3)
ALLOCATION FACTORS					
1	MAX. DEMAND 24-HOUR USE		2,016,610	1,508,771	507,839
2	PERCENT	D01	100.000000%	74.817193%	25.182807%
3					
4	MAX. DEMAND 1 HR. NON-COINC.		119,958	95,143	24,815
5	PERCENT	D02	100.000000%	79.313593%	20.686407%
6					
7	ANNUAL GAS SALES TO CUSTOMERS		196,743,672	144,769,861	51,973,811
8	PERCENT	E01	100.000000%	73.582982%	26.417018%
9					
10	CUSTOMER FOOTAGE OF MAINS		5,814,590	5,546,290	268,300
11	PERCENT	C01	100.000000%	95.385745%	4.614255%
12					
13	BOOK COST - SERVICES		130,618,371	121,083,930	9,534,441
14	PERCENT	C02	100.000000%	92.700536%	7.299464%
15					
16	BOOK COST OF METERS		42,387,457	31,238,244	11,149,213
17	PERCENT	C03	100.000000%	73.696905%	26.303095%
18					
19	CUSTOMER ACCOUNTING EXP.		4,369,906	4,130,192	239,714
20	PERCENT	C04	100.000000%	94.514436%	5.485564%
21					
22	UNCOLLECTIBLE ACCOUNTS		639,773	615,106	24,667
23	PERCENT	C05	100.000000%	96.144449%	3.855551%
24					
25	CUSTOMER SERVICE EXP.		1,917,433	1,813,152	104,281
26	PERCENT	C08	100.000000%	94.561427%	5.438573%
27					
28	RECEIPTS PROCESSING		207,101	195,838	11,263
29	PERCENT	C06	100.000000%	94.561591%	5.438409%
30					
31	PRINTING & MAILING A BILL		320,535	303,102	17,433
32	PERCENT	C07	100.000000%	94.561280%	5.438720%
33					
34	CUSTOMER INSTALLATION EXP.		126,600	119,504	7,096
35	PERCENT	CIL	100.000000%	94.394945%	5.605055%
36					
37	ADJ. REVENUES FROM SALES		83,979,990	66,889,835	17,090,155
38	PERCENT	R01	100.000000%	79.649730%	20.350270%
39					
40	COMPETITIVE REVENUES		3,039,716	2,827,162	212,554
41	PERCENT	R02	100.000000%	93.007431%	6.992569%
42					
43	MISCELLANEOUS REVENUES		3,615,959	3,363,110	252,849
44	PERCENT	R03	100.000000%	93.007415%	6.992585%
45					
46	UNBUNDLED ALLOCATOR		905,959	865,293	40,666
47	PERCENT	U01	100.000000%	95.511276%	4.488724%
48					
49	NULL REVENUE FACTOR		0	0	0
50	PERCENT	R99	0.000000%	0.000000%	0.000000%
51					
52	NUMBER OF CUSTOMERS	K09	125,213	118,403	6,810

EXHIBIT G-14
SCHEDULE 1
TABLE 1A

Orange and Rockland Utilities, Inc.
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	6.38%			
SC 1 Residential & Space Heating	4.38%	(5,359,986)		(5,359,986)
SC 2 General Service	21.53%	7,536,327	(2,176,341)	5,359,986
Total System		2,176,341	(2,176,341)	0

* Deficiencies shown as negative

** Applied to deficiency only

Orange & Rockland Utilities, Inc.
Merchant Function Cost Components
Supply Portion of the MFC for Full Service Customers
Based on the 2007 Gas Embedded Cost-of-Service Study

	RESIDENTIAL & SPACE HTG <u>SC NO. 1</u>	GENERAL SERVICE <u>SC NO. 2</u>	Total <u>O&R</u>
1 Supply portion of the MFC	775,674	36,717	812,391
2			
3 Total O&R T&D, MFC-Commodity Procurement,			\$ 87,019,706
4 MFC-Credit & Collection, and BPP Revenues			
5			
6 Fixed Rate of Revenue Requirement	<u>0.89138%</u>	<u>0.04219%</u>	<u>0.93357%</u>
7 (as % of total revenues)			

Orange & Rockland Utilities, Inc.
Merchant Function Cost Components
Credit & Collection Portion of the MFC for Full Service Customers and POR Discount
Based on the 2007 Gas Embedded Cost-of-Service Study

	RESIDENTIAL & SPACE HTG SC NO. 1	GENERAL SERVICE SC NO. 2	Total O&R
1 Full Service Portion of Credit & Collection	445,297	20,665	465,962
2			
3 Total O&R T&D, MFC-Commodity Procurement,			\$ 87,019,706
4 MFC-Credit & Collection, and BPP Revenues			
5			
6 Fixed Rate of Revenue Requirement	<u>0.51172%</u>	<u>0.02375%</u>	<u>0.53547%</u>
7 (as % of total revenues)			
8 POR Portion of Credit & Collection	322,969	61,858	384,827
9			
10 Total O&R T&D, MFC-Commodity Procurement,			\$ 87,019,706
11 MFC-Credit & Collection, and BPP Revenues			
12			
13 as % of total revenues	<u>0.37114%</u>	<u>0.07109%</u>	<u>0.44223%</u>
14			

Orange & Rockland Utilities, Inc.
Exhibit for The Printing and Mailing a Bill Function
Based on the 2007 Gas Embedded Cost-of-Service Study

<u>Description</u>		Total O&R Printing & Mailing Gas	Printing & Mailing Gas Labor	Printing & Mailing Gas Non-Labor	
Line 1	Total Mailing Charges	399,755	45,138	354,618	Line 1
Line 2					Line 2
Line 3	<u>Revenue Allocations</u>				Line 3
Line 4					Line 4
Line 5	Allocation of Credit and Collection	\$1,522	1,307	215	Line 5
Line 6	Allocation of Educ-Cust Advertising/Promotion	70	-	70	Line 6
Line 7	Allocation of Uncollectibles	791	-	791	Line 7
Line 8	Total Customer Care/Service Revenue Allocation	\$2,383	1,307	1,076	Line 8
Line 9					Line 9
Line 10	Printing & Mailing a Bill before Overheads	\$ 402,138	46,444	355,693	Line 10
Line 11					Line 11
Line 12	Overheads	\$16,593			Line 12
Line 13					Line 13
Line 14	Total Printing & Mailing a Bill	\$ 418,731			Line 14
Line 15					Line 15
Line 16	Total Mailings Allocated to O&R Gas	<u>939,436</u>			Line 16
Line 17					Line 17
Line 18	Average Unit Cost per Bill per Month	<u>\$0.4457</u>			Line 18

Orange and Rockland Utilities, Inc.
Exhibit for The Receipts Processing Function
Based on the 2007 Gas Embedded Cost-of-Service Study

<u>Description</u>		Total O&R Receipts Processing Gas	Receipts Processing Gas Labor	Receipts Processing Gas Non-Labor	
Line 1	Total Receipts Processing Charges	\$ 75,147	27,710	47,437	Line 1
Line 2					Line 2
Line 3	Allocation of Customer Care	\$ 170,712	161,955	8,757	Line 3
Line 4					Line 4
Line 5	Total Receipts Processing	\$ 245,859	189,665	56,194	Line 5
Line 6					Line 6
Line 7	<u>Revenue Allocations</u>				Line 7
Line 8					Line 8
Line 9	Allocation of Credit and Collection	\$ 936	804	133	Line 9
Line 10	Allocation of Educ-Cust Advertising/Promotion	43	-	43	Line 10
Line 11	Allocation of Uncollectibles	486	-	486	Line 11
Line 12	Total Customer Care/Service Revenue Allocation	\$ 1,465	\$ 804	\$ 662	Line 12
Line 13					Line 13
Line 14	Receipts Processing before Overheads	\$ 247,324	190,469	56,856	Line 14
Line 15					Line 15
Line 16	Overheads	\$ 206,049			Line 16
Line 17					Line 17
Line 18	Total Receipts Processing	\$ 453,373			Line 18
Line 19					Line 19
Line 20	Total Mailings Allocated to O&R Gas	<u>939,436</u>			Line 20
Line 21					Line 21
Line 22	Average Unit Cost per Bill per Month	<u>\$0.4826</u>			Line 22

Exhibit G-14
Schedule 4

Orange & Rockland Utilities, Inc.
Gas Transmission and Distribution Marginal Costs

(1)	Average Annual Capital Investment Years 2009-2013	\$4,134,000
(2)	Carrying Charge	11%
(3)	Annualized Cost (1) x (2)	\$454,740
(4)	O&M Expense = 8.41% x (1)	\$347,669
(5)	Total Annual Cost Including O&M	\$802,409
(6)	Incremental Annual Sales (Average of Years 2009-2013)	1,792,827
(7)	Total Marginal Cost (Dollars per Ccf)	<u>\$0.4476</u>

ORANGE AND ROCKLAND UTILITIES, INC.
TESTIMONY OF
MICHAEL J. THORPE
NYPSC CASE NO. _____

Exhibit G-15

PSC Complaint Rate (1)	Tier Range	Penalty/Incentive
Incentive	<0.9	\$ 300,000
	<2.5	\$ 0
Penalty	2.5	\$ 100,000
Penalty	2.6	\$ 200,000
Penalty	>2.7	\$ 300,000
PSC Complaint Rate If Exceptional Results in Prior Year. Exceptional Results is <=0.9	Tier Range	Penalty/Incentive
Incentive	<0.9	\$ 300,000
	<2.5	\$ 0
Penalty	2.5	\$ 75,000
Penalty	2.6	\$ 150,000
Penalty	>2.7	\$ 300,000
Residential Customer Assessment Survey (RCAS)	Tier Range	Penalty/Incentive
Incentive	>=7.29	\$ 150,000
	>=6.99 (2)	\$ 0
Penalty	6.84 – 6.98	\$ 30,000
Penalty	6.69 – 6.83	\$ 75,000
Penalty	< 6.69	\$ 150,000
C&I Customer Assessment Survey (CICAS)	Tier Range	Penalty/Incentive
Incentive	>=7.23	\$ 150,000
	>=6.73 (2)	\$ 0
Penalty	6.48 – 6.72	\$ 30,000
Penalty	6.23 – 6.47	\$ 75,000
Penalty	< 6.23	\$ 150,000
Maximum Incentive		\$ 600,000
Maximum Penalty		\$ 600,000

(1) Complaint Rate will be calculated in the manner approved by the Commission in its Order approving Complaint Rate Targets issued August 26, 2005 in Case 02-G-1553 and Case 03-E-0797.

(2) RCAS and CICAS Target exclude price factor as ordered and approved in Case 07-E-0949.