DEPARTMENT OF THE ARMY
UNITED STATES ARMY LEGAL SERVICES AGENCY
901 NORTH STUART STREET
ARLINGTON VA 22203-1837

REPLY TO
ATTENTION OF

16 APRIL 2004

Regulatory Law Office
U4117

SUBJECT: In the Matter of Adjustment of Gas and Electric Rates of Louisville Gas and Electric Company, KY PSC Case No. 2003-00433

RECEIVED

APR 19 2004

PUBLIC SERVICE
COMMISSION

Hon. Thomas M. Dorman
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, KY 40602

Dear Mr. Dorman:

Enclosed for filing find the original and eight copies of the Responses of intervenor, the consumer interest of the United States Department of Defense and other affected Federal Executive Agencies (hereinafter "DOD") to the First Data Request of the Staff of the Public Service Commission (Staff) in the above styled proceeding.

Copies of this pleading are being sent in accord with the Certificate of Service. Inquiries regarding this proceeding should be directed to the undersigned at the address above or at telephone number (703) 696-1646.

Sincerely yours

David A. McCormick

David A. McCormick
General Attorney

CF: Certificate of Service
Hon. Daniel M. Kininmonth, Fort Knox, KY

Certificate of Service

I certify that I have caused a copy of this document to be sent to the following addressees by first class, postage prepaid, U.S. Mail:

Hon. Kendrick R. Riggs
Ogden, Newell, & Welch
1700 Citizens Plaza
500 West Jefferson Street
Louisville, KY 40202-2874

Hon. Linda S. Portasik
Senior Corporate Attorney
Louisville Gas and Electric Company
220 W. Main Street
P.O. Box 32010
Lousiville, KY 40232-2010

Office of the Staff Judge Advocate
HQ, US Army Armor Center & Fort Knox
ATTN: ATZK-JA (Hon. Daniel M. Kininmonth)
Fort Knox, KY 40121-5000

Mr. Michael S. Beer
Vice President, Rates & Regulatory
Louisville Gas and Electric Company
P.O. Box 32010
Louisville, KY 40232-2010

Hon. Robert M. Watt
Stoll, Keenon & Park
300 West Vine Street, Suite 2100
Lexington, KY 40507-1801

Hon. Michael L. Kurtz
Boehm, Kurtz & Lowry
Suite 2110
36 East Seventh Street
Cincinnati, OH 45202

Hon. Elizabeth E. Blackford
Assistant Attorney General
1024 Capital Center Avenue, Suite 200
Frankfort, KY 40601

Hon. Joe F. Childers
Attorney at Law
201 W. Short Street, Suite 310
Lexington, KY 40507

Hon. David C. Brown
Stites & Harbison
1800 Aegon Center
400 West Market Street
Louisville, KY 40202

Hon. Lisa Kilkelly
LEGAL AID SOCIETY, INC.
425 Muhammad Ali Blvd.
Louisville, KY 40202

Hon. Iris Skidmore
Office of Legal Services, Division. of Energy
Environmental and Public Protection Cabinet
Fifth Floor, Capital Plaza Tower
Frankfort, KY 40601

Hon. David J. Barbarie
Department of Law
Lexington-Fayette Urban County Government
200 East Main Street
Lexington, KY 40507

Dated this 16th day of April 2004, at Arlington County, Virginia.

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Lexington, KY 40507

Dated this 16th day of April 2004, at Arlington County, Virginia.

David R. McCormick

US DEPARTMENT OF DEFENSE RESPONSES TO
FIRST DATA REQUEST OF STAFF

TABLE OF CONTENTS

REQUEST FOR INFORMATION TO THE DEPARTMENT OF DEFENSE BY

THE COMMISSION STAFF

First Data Request - Question No. 1

Responding Witness: Thomas J. Prisco

Q-1. Refer to the Direct Testimony of Thomas J. Prisco ("Prisco Testimony"), pages 8 and 9, concerning Louisville Gas and Electric Company's ("LG&E") proposed depreciation expense adjustment. If depreciation issues are excluded from a general rate case and addressed in a separate proceeding, explain how the results from the separate depreciation proceeding can be reflected in the base rates paid by customers.

A-1. Mr. Prisco believes rates should not be adjusted based on single issue rate making and recommends deferring recovery until the next general rate proceeding.

Q-2. Refer to the Prisco Testimony, pages 10 and 11.

a. Explain the reason(s) why a regulatory asset and/or credit should be established for LG&E's pensions and post-retirement expenses.

b. Explain the purpose for the recommendation that "a band be established that would require a refund or recovery if or when the account reaches a specific threshold."

c. Three companies are identified on page 11 as having adopted some type of deferred accounting mechanism for pensions and post-retirement benefits.

(1) Describe the circumstances that led to the establishment of the deferred accounting mechanism for each company.

(2) Provide copies of the commission orders establishing the deferred accounting mechanism for each company.

(3) Identify and explain any differences between the deferred accounting mechanisms authorized for three listed companies and the recommendation for LG&E.

A-2a. Mr. Prisco believes his recommendation will help mitigate the impact of fluctuations in stock market and other investments.

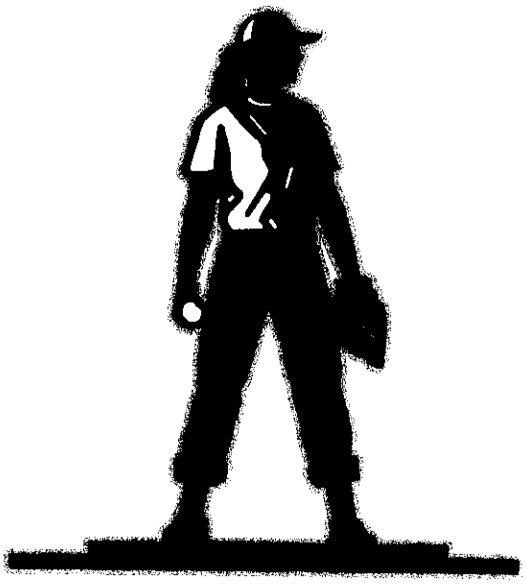
A-2b. Mr. Prisco believes a band/threshold should be established to mitigate the volatile fluctuations in the stock market. A refund or recovery will only be required when a substantial imbalance develops.

A-2c. (1) Mr. Prisco is not specifically familiar with the circumstances that led to the establishment of the deferred mechanism for each of the three companies. It would appear however that it corresponded with the implementation of FASB 106.

(2) Mr. Prisco obtained his information regarding deferred accounting treatment from the currently available annual reports of the referenced Companies. Copies of the specific pages of the annual reports are attached for your review. Mr. Prisco is also providing copies of orders, where available (New York & the District of Columbia), that address deferred accounting for pensions and OPEB for the referenced companies.

(3) Each of the three referenced companies use a slightly different mechanism for handling deferred accounting for pensions and OPEB costs. These mechanisms can be reviewed on the attached pages from each company's the 10K. LG&E on-the-other-hand proposes to increase pro-forma expenses for the shortfall in pension and post retirement. This increased level of funding continues irrespective of market conditions and until the next general rate proceeding.

ENTERGY 2002 ANNUAL REPORT



STANDING UP AND STANDING OUT

Entergy

In July 1997, Entergy Louisiana caused the Waterford 3 lessors to issue $307.6 million aggregate principal amount of Waterford 3 Secured Lease Obligation Bonds, 8.09% Series due 2017, to refinance the outstanding bonds originally issued to finance the purchase of the undivided interests by the lessors. The lease payments have been reduced to reflect the lower interest costs.

As of December 31, 2002, System Energy and Entergy Louisiana had future minimum lease payments, recorded as long-term debt (reflecting an overall implicit rate of 7.02% and 7.45%, respectively) as follows (in thousands):

	System Energy	Entergy Louisiana
2003	$ 48,524	$ 59,709
2004	36,133	31,739
2005	52,253	14,554
2006	52,253	18,261
2007	52,253	18,754
Years thereafter	418,022	389,121
Total	659,438	532,138
Less: Amount representing interest	244,595	234,188
Present value of net minimum lease payments	$414,843	$297,950

NOTE 11. RETIREMENT AND OTHER POSTRETIREMENT BENEFITS

PENSION PLANS

Entergy has seven pension plans covering substantially all of its employees: "Entergy Corporation Retirement Plan for Non-Bargaining Employees," "Entergy Corporation Retirement Plan for Bargaining Employees," "Entergy Corporation Retirement Plan II for Non-Bargaining Employees," "Entergy Corporation Retirement Plan II for Bargaining Employees," "Entergy Corporation Retirement Plan III," "Entergy Corporation Retirement Plan IV for Non-Bargaining Employees," and "Entergy Corporation Retirement Plan IV for Bargaining Employees." Except for the Entergy Corporation Retirement Plan III, the pension plans are noncontributory and provide pension benefits that are based on employees' credited service and compensation during the final years before retirement. The Entergy Corporation Retirement Plan III includes a mandatory employee contribution of 3% of earnings during the first 10 years of plan participation, and allows voluntary contributions from 1% to 10% of earnings for a limited group of employees. Entergy Corporation and its subsidiaries fund pension costs in accordance with contribution guidelines established by the Employee Retirement Income Security Act of 1974, as amended, and the Internal Revenue Code of 1986, as amended. The assets of the plans include common and preferred stocks, fixed-income securities, interest in a money market fund, and insurance contracts. As of December 31, 2002, Entergy recognized an additional minimum pension liability for the excess of the accumulated benefit obligation over the fair market value of plan assets. In accordance with FASB 87, an offsetting intangible asset, up to the amount of any unrecognized prior service cost, was also recorded, with the remaining offset to the liability recorded as a regulatory asset reflective of the recovery mechanism for pension costs in Entergy's jurisdictions. Entergy's pension costs are recovered from customers as a component of cost of service in each of its jurisdictions.

Total 2002, 2001, and 2000 pension costs of Entergy Corporation and its subsidiaries, including amounts capitalized, included the following components (in thousands):

	2002	2001	2000
Service cost - benefits earned during the period	$ 56,947	$ 49,166	$ 37,130
Interest cost on projected benefit obligation	128,387	118,448	108,782
Expected return on assets	(158,202)	(157,889)	(145,717)
Amortization of transition asset	(763)	(7,142)	(9,740)
Amortization of prior service cost	5,993	5,735	12,953
Recognized net (gain)/loss	5,504	(6,573)	(8,576)
Net pension costs/(income)	$ 37,866	$ 1,745	$ (5,168)

The funded status of Entergy's pension plans as of December 31, 2002 and 2001 was (in thousands):

	2002	2001
Change in Projected Benefit Obligation (PBO)		
Balance at beginning of year	$1,720,492	$1,602,673
Service cost	56,947	49,166
Interest cost	128,387	118,448
Acquisition of subsidiary	33,398	212
Actuarial loss	144,531	16,369
Benefits paid	(91,548)	(88,476)
Acquisition	–	22,100
Balance at end of year	$1,992,207	$1,720,492
Change in Plan Assets		
Fair value of assets at beginning of year	$1,686,836	$1,843,115
Actual return on plan assets	(191,136)	(80,335)
Employer contributions	12,857	10,532
Employee contributions	1,125	2,000
Acquisition of subsidiary	33,668	–
Benefits paid	(91,548)	(88,476)
Fair value of assets at end of year	$1,451,802	$1,686,836
Funded status	$ (540,405)	$ (33,656)
Unrecognized transition asset	(2,189)	(3,202)
Unrecognized prior service cost	37,351	40,330
Unrecognized net (gain)/loss	413,043	(70,934)
Accrued pension cost	$ (92,200)	$ (67,462)
Amounts recognized in balance sheet		
Accrued pension cost	$ (92,200)	$ (67,462)
Additional minimum pension liability	(208,151)	–
Intangible asset	33,346	–
Accumulated other comprehensive income	17,016	–
Regulatory asset	157,789	–
Net amount recognized	$ (92,200)	$ (67,462)

OTHER POSTRETIREMENT BENEFITS

Entergy also provides health care and life insurance benefits for retired employees. Substantially all domestic employees may become eligible for these benefits if they reach retirement age while still working for Entergy.

Effective January 1, 1993, Entergy adopted SFAS 106, which required a change from a cash method to an accrual method of accounting for postretirement benefits other than pensions. At January 1, 1993, the actuarially determined accumulated postretirement benefit obligation (APBO) earned by retirees and active employees was estimated to be approximately $241.4 million for Entergy (other than Entergy Gulf States) and $128 million for Entergy Gulf States. Such obligations are being amortized over a 20-year period that began in 1993.

Entergy Arkansas, the portion of Entergy Gulf States regulated by the PUCT, Entergy Mississippi, and Entergy New Orleans have received regulatory approval to recover SFAS 106 costs through rates. Entergy Arkansas began recovery in 1998, pursuant to an APSC order. This order also allowed Entergy Arkansas to amortize a regulatory asset (representing the difference between SFAS 106 costs and cash expenditures for other postretirement benefits incurred for a five-year period that began January 1, 1993) over a 15-year period that began in January 1998.

The LPSC ordered the portion of Entergy Gulf States regulated by the LPSC and Entergy Louisiana to continue the use of the pay-as-you-go method for ratemaking purposes for postretirement benefits other than pensions. However, the LPSC retains the flexibility to examine individual companies' accounting for postretirement benefits to determine if special exceptions to this order are warranted.

Pursuant to regulatory directives, Entergy Arkansas, Entergy Mississippi, Entergy New Orleans, the portion of Entergy Gulf States regulated by the PUCT, and System Energy fund postretirement benefit obligations collected in rates. System Energy is funding on behalf of Entergy Operations postretirement benefits associated with Grand Gulf 1. Entergy Louisiana and Entergy Gulf States continue to recover a portion of these benefits regulated by the LPSC and FERC on a pay-as-you-go basis. The assets of the various postretirement benefit plans other than pensions include common stocks, fixed-income securities, and a money market fund.

Total 2002, 2001, and 2000 other postretirement benefit costs of Entergy Corporation and its subsidiaries, including amounts capitalized and deferred, included the following components (in thousands):

	2002	2001	2000
Service cost - benefits earned during the period	$ 29,199	$ 24,225	$ 18,252
Interest cost on APBO	44,819	38,811	34,022
Expected return on assets	(14,066)	(12,578)	(10,566)
Amortization of transition obligation	17,874	17,874	17,874
Amortization of prior service cost	992	992	520
Recognized net (gain)/loss	1,874	(1,506)	(3,070)
Net postretirement benefit cost	$ 80,692	$ 67,818	$ 57,032

The funded status of Entergy's other postretirement benefit plans as of December 31, 2002 and 2001 was (in thousands):

	2002	2001
Change in APBO		
Balance at beginning of year	$ 590,731	$ 507,756
Service cost	29,199	24,225
Interest cost	44,819	38,811
Actuarial loss	159,143	44,289
Benefits paid	(35,861)	(37,403)
Acquisition of subsidiary	11,475	13,053
Balance at end of year	$ 799,506	$ 590,731
Change in Plan Assets		
Fair value of assets at beginning of year	$ 158,190	$ 143,038
Actual return on plan assets	(11,559)	663
Employer contributions	59,542	51,892
Benefits paid	(35,861)	(37,403)
Acquisition of subsidiary	12,380	–
Fair value of assets at end of year	$ 182,692	$ 158,190
Funded status	$(616,814)	$(432,541)
Unrecognized transition obligation	114,724	126,196
Unrecognized prior service cost	3,522	4,514
Unrecognized net loss	245,795	70,208
Accrued postretirement benefit cost	$(252,773)	$(231,623)

The assumed health care cost trend rate used in measuring the APBO of Entergy was 10% for 2003, gradually decreasing each successive year until it reaches 4.5% in 2009 and beyond. A one percentage point increase in the assumed health care cost trend rate for 2002 would have increased the APBO and the sum of the service cost and interest cost of Entergy as of December 31, 2002, by approximately $87.8 million and $10.6 million, respectively. A one percentage point decrease in the assumed health care cost trend rate for 2002 would have decreased the APBO and the sum of the service cost and interest cost of Entergy as of December 31, 2002, by approximately $79.8 million and $9.4 million, respectively.

The significant actuarial assumptions used in determining the pension PBO and the SFAS 106 APBO for 2002, 2001, and 2000 were as follows:

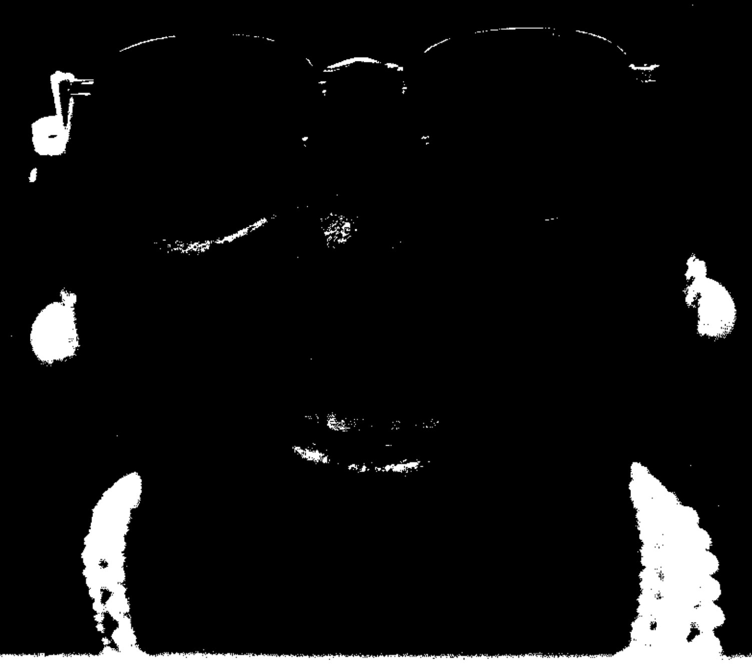
	2002	2001	2000
Weighted-average discount rate	6.75%	7.50%	7.50%
Weighted-average rate of increase in future compensation levels	3.25%	4.60%	4.60%
Expected long-term rate of return on plan assets:			
Taxable assets	5.50%	5.50%	5.50%
Non-taxable assets	8.75%	9.00%	9.00%

Entergy's remaining pension transition assets are being amortized over the greater of the remaining service period of active participants or 15 years, and its SFAS 106 transition obligations are being amortized over 20 years.

WGL Holdings, Inc.

Annual Report 2003

Sustainable growth



Company's basic and diluted EPS for WGL Holdings for fiscal years ended September 2003, 2002 and 2001, respectively.

Basic EPS and Diluted EPS

(In thousands, except per share data)	Net Income	Shares	Per Share Amount
Year Ended September 30, 2003			
Basic EPS:			
Net income	**$112,342**	**48,587**	**$2.31**
Stock-based compensation plans	**-**	**169**	
Diluted EPS:			
Net income	**$112,342**	**48,756**	**$2.30**
Year Ended September 30, 2002			
Basic EPS:			
Net income	$ 39,121	48,563	$0.81
Stock-based compensation plans	-	88	
Diluted EPS:			
Net income	$ 39,121	48,651	$0.80
Year Ended September 30, 2001			
Basic EPS:			
Net income	$ 82,445	47,120	$1.75
Stock-based compensation plans	-	70	
Diluted EPS:			
Net income	$ 82,445	47,190	$1.75

11. INCOME TAXES

The Company and its subsidiaries file a consolidated federal income tax return. The Company's federal income tax returns for all years through September 30, 1999 have been reviewed and closed, or closed without review by the Internal Revenue Service. The Company and its subsidiaries also participate in a tax sharing agreement that establishes the method for allocating losses utilized on a consolidated federal income tax return. State income tax returns are filed on a separate company basis in states where the Company has operations and/or a requirement to file.

The Statements of Income Taxes provide the following: *(i)* the components of income tax expense; *(ii)* a reconciliation between the statutory federal income tax rate and the effective income tax rate; and *(iii)* the components of accumulated deferred income tax assets and liabilities at September 30, 2003 and 2002.

During fiscal year ended September 30, 2003, the Company recognized tax benefits of $2.4 million from the release of a valuation allowance associated primarily with previously unrecognized capital losses. A valuation allowance of $4.0 million remained for unused tax benefits of capital losses as of September 30, 2003.

12. PENSION AND OTHER POST-RETIREMENT BENEFIT PLANS

Washington Gas maintains a qualified, trusteed, non-contributory defined benefit pension plan covering all active and vested former employees of Washington Gas. To the extent allowable by law, Washington Gas funds pension costs accrued for the qualified plan. Assets under the defined benefit pension plan are valued using a method designed to spread realized and unrealized asset gains and losses from all assets over a period of five years.

Executive officers of Washington Gas also participate in a non-funded supplemental executive retirement plan (SERP). A rabbi trust has been established for the potential future funding of the SERP liability.

As of September 30, 2003, the Company had recorded a minimum pension obligation that included $5.3 million in regards to the SERP with corresponding adjustments to "Regulatory assets" and "Other comprehensive income" of $4.2 million and $1.1 million, respectively. Based on the regulatory treatment in certain jurisdictions, the Company believes that it will be able to ultimately recover a significant portion of the additional minimum liability through future rates. Should the Company not recover this minimum liability through future rates, a balance sheet adjustment would be made to reclassify the obligation from "Regulatory assets" to "Other comprehensive income," a component of "Common shareholders' equity."

Certain subsidiaries of the Company offer defined-contribution savings plans to eligible employees, covering all employee groups. These plans allow participants to defer on a pre-tax or after-tax basis, a portion of their salaries for investment in various alternatives. The Company makes matching contributions to the amounts contributed by employees in accordance with the specific plan provisions. The Company's contribution to the plans were $3.0 million, $2.9 million and $2.6 million during fiscal years 2003, 2002 and 2001, respectively.

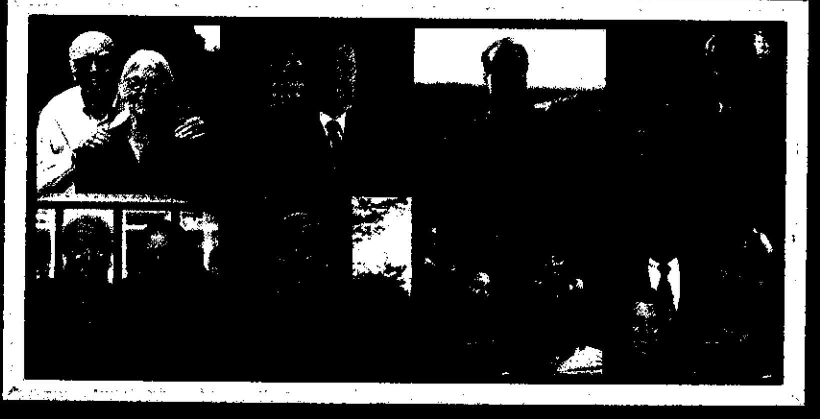
The Company provides certain healthcare and life insurance benefits for retired employees. Substantially all employees of the regulated utility may become eligible for such benefits if they attain retirement status while working for Washington Gas. The Company accounts for these benefits under the provisions of SFAS No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions*. The Company elected to amortize the accumulated post-retirement benefit obligation of $190.6 million existing at the October 1, 1993 adoption date of this standard, known as the transition obligation, over a twenty-year period. Effective January 1, 2004, changes are being made to post-retirement medical benefits that reduced the Company's post-retirement benefit obligations by $37.9 million as of September 30, 2003.

CH Energy Group, Inc.

2002

Annual Report and Form 10-K

A Shared Commitment to Value



Note 8
Post-Employment Benefits

Pension Benefits

Central Hudson has a non-contributory retirement me plan ("Retirement Plan") covering substan- y all of its employees and certain employees of CHEC. The Retirement Plan provides pension benefits that are based on the employee's compensation and years of service. It has been Central Hudson's practice to provide periodic updates to the benefit formula stated in the Retirement Plan.

During the quarter ended September 2002, Central Hudson contributed $32 million to the Trust Fund for the Retirement Plan to avoid a pension fund deficit arising from declines in the market value of the Trust Fund's investment portfolio and a reduction in the discount rate used to determine the accumulated benefit obligation. Under the policy of the PSC regarding pension costs, differences between pension expense and rate allowances covering pension expenses are deferred for future recovery from customers and carrying charges are accrued on cash differences. The $32 million contribution is subject o such carrying charges.

ecent circumstances noted above have resulted n a significant increase in annual pension expense s compared to the level upon which current rates vere set. This difference is deferred under the SC's policy for recovery of pension expense and ost-retirement benefits. This deferral, if it contin- es in the future, could result in the accumulation f a significant regulatory asset which Central Hud- on will seek to recover as provided for under the SC's policy.

entral Hudson's accounts for pension in accor- ance with PSC-prescribed provisions which, mong other things, require ten-year amortization actuarial gains and losses. As authorized by the SC, any difference between the amount collected rates and the actual amount recorded as net peri- ic pension cost was deferred as either a regulatory set or liability, as appropriate. The pension assets d liabilities transferred to Dynegy as a result of e of Central Hudson's interests in the mmer Plant and the Roseton Plant were lected in the amount recorded in 2001 for net riodic pension cost.

In addition to the Retirement Plan, Central Hudson's and Energy Group's officers and executives are covered under a non-qualified Directors and Executives Deferred Compensation Plan and a non-qualified Supplementary Retirement Plan. Central Hudson also sponsors a non-qualified Retirement Benefit Restoration Plan.

Other Post-Retirement Benefits

Central Hudson provides certain health care and life insurance benefits for retired employees through its post-retirement benefit plans. Substantially all of Central Hudson's employees may become eligible for these benefits if they reach retirement age while employed by Central Hudson. These and similar benefits for active employees are provided through insurance companies whose premiums are based on the benefits paid during the year. In order to reduce the total costs of these benefits, Central Hudson requires employees who retired on or after October 1, 1994 to contribute toward the cost of these benefits.

Central Hudson is fully recovering its net periodic post-retirement costs in accordance with PSC guidelines. Under these guidelines, the difference between the amounts of post-retirement benefits recoverable in rates and the amounts of post-retirement benefits determined by an actuary under SFAS 106, *Employers Accounting for Post-retirement Benefits Other Than Pensions*, is deferred as either a regulatory asset or liability, as appropriate.

As of December 31, 2002, the only post-retirement benefits provided to employees of any of the competitive business subsidiaries were those offered to employees of CHEC, who are allowed to participate in the Central Hudson benefit plans. All other employees of the competitive business subsidiaries are eligible to participate in Griffith Energy's 401(k) plan. No other post-retirement benefits are provided.

*1993 N.Y. PUC LEXIS 33, *; 33 NY PSC 1107*

Policy on Pensions/OPEBs

Case 91-M-0890

New York Public Service Commission

1993 N.Y. PUC LEXIS 33; 33 NY PSC 1107

September 7, 1993

CORE TERMS: pension, accounting, deferral, allowance, phase-in, savings, ratemaking, funding, external, rate base, settlement, accrual, early retirement, ratepayer, deferred, jurisdictional, tax-effective, corridor, annual, rate proceeding, customer, curtailment, calculation, retiree, notification, debit, effective, long-term, deposit, qualify

PANEL: **[*1]** Commissioners present: Peter Bradford, Chairman; Lisa Rosenblum; Harold A. Jerry, Jr.; William D. Cotter; Raymond J. O'Connor

OPINION: Statement of Policy and Order Concerning the Accounting and Ratemaking Treatment for Pensions And Postretirement Benefits Other Than Pensions

I. INTRODUCTION

On March 19, 1992, we issued a Notice Soliciting Comments (Notice) which contained a staff proposal regarding the accounting and ratemaking treatment to be applied to three major and inter-related accounting pronouncements issued by the Financial Accounting Standards Board (FASB). n1 These three standards are:

--Statement of Financial Accounting Standards (SFAS) No. 87--"Employers' Accounting for Pensions"
--SFAS No. 88--"Employers' Accounting for Settlements and Curtailments of Defined Benefits Pension Plans and for Termination Benefits"
--SFAS No. 106--"Employers' Accounting for Post-retirement Benefits Other Than Pensions" n2

n1 The FASB is the private sector's independent rulemaking body for the accounting profession. Although the Securities and Exchange Commission (SEC) has statutory authority to establish financial and reporting standards, the FASB's standards are officially recognized as authoritative by the SEC and the American Institute of Certified Public Accountants. **[*2]**

n2 SFAS No. 106 is generally effective for fiscal years beginning in 1993. However, it is not mandatory until fiscal years beginning after December 15, 1994 for employers who have less than 500 plan participants and are non-public enterprises. The Statement of Policy recognizes this delay feature for the small companies.

Although the first two pronouncements were generally effective in 1987, n3 we awaited the FASB's issuance of an Exposure Draft on the accounting for Postretirement Benefits Other Than Pensions (OPEB) in the summer of 1989, before beginning the process of developing a generic Statement of Policy on these interrelated accounting principles. All three standards deal with the complex issues of accounting for, and measurement of, employers' cost of employee benefits received after retirement, but earned during the employees' working career. Since pensions and OPEBs are both forms of deferred compensation, and since the pronouncements are complementary, we are addressing their accounting/ratemaking treatment in one Statement of Policy (Policy).

n3 On September 22, 1987, we issued an Order authorizing companies to adopt the provisions of SFAS No. 87 if done in the context of a rate proceeding. Companies can adopt SFAS No. 87 outside of a rate proceeding, but only if the differences between pension expense, as calculated under SFAS No. 87, and current rate allowances were deferred for Commission disposition. **[*3]**

II. OVERVIEW

After a careful review of all comments submitted in response to the Notice, n4 we are adopting all three accounting standards, with some revisions to the provisions specified in the Notice, for accounting and ratemaking purposes effective with this Order and retroactive to January 1, 1993. All affected companies must have their regulatory accounting records in compliance with this Policy by October 1, 1993.

n4 Thirty parties responded to Staff's proposal; 25 jurisdictional utilities, 2 of the "Big Six" accounting firms and 3 Intervenors who often participate in rate cases (the New York State Consumer Protection Board (CPB), Multiple Intervenors, and Federal Executive Agencies). A list of the respondents is attached as Appendix B.

The Statement of Policy n5 shall be followed in all instances for regulatory accounting and ratemaking purposes unless particular circumstances demonstrate it to be inappropriate or unwarranted. Before special treatment will be allowed, the party seeking divergent treatment must: (1) demonstrate that the cost or other impact of implementing the contested provision (s) would be an unjustifiable burden on its New York utility ratepayers, **[*4]** and (2) submit an alternative plan that fulfills the objectives of the Policy.

n5 Attached as Appendix A.

In the broadest sense, the Policy merges two, sometimes competing, objectives into a comprehensive accounting/ratemaking strategy: it blends a desire to recognize generally accepted accounting principles (GAAP) in Commission rate decisions (when they do not conflict with our regulatory objectives) with the need to introduce accounting changes into rates in a smooth and efficient manner.

In summary, the Policy accomplishes the following primary objectives:

. adopts the three GAAP pronouncements for accounting and ratemaking purposes. For SFAS Nos. 87 and 88, it utilizes some options for the new accounting rules to recognize pension gains (and losses) faster than most companies heretofore have chosen to do. It also preserves other pension savings and, together with pension gains, directs their use to mitigate increases in future OPEB rate allowances.
. adopts recognition of OPEB costs in rates as they are earned by employees (accrual accounting). This constitutes a switch from the current pay-as-you-go (cash basis) practice.
. moderates the rate impact of adopting **[*5]** accrual accounting for OPEB

through the use of a phase-in plan and a long-term amortization of the obligation that has built up in the past.

III. MAJOR PROVISIONS OF THE STATEMENT OF POLICY

The Policy accomplishes its main objectives through the following features:

. mitigates the substantial rate impacts related to adopting SFAS No. 106 by:

. establishing a rate phase-in plan for OPEB that allows five-years for rate allowances to reach the full annual SFAS No. 106 expense level;
. amortizing over 20 years the OPEB liability that has built up over approximately the last 2 decades (the transition obligation);
. rededicating excess pension plan assets (where available) to begin funding future OPEB liabilities;
. amortizing previously unrecognized pension gains (where available); and
. preserving pension expense reductions (past and future) occasioned by the adoption of SFAS No. 87.

. complies with GAAP by adopting accrual accounting for OPEB and establishing a rate phase-in plan that conforms with FASB guidelines.
. is consistent with the accounting and ratemaking treatment for pensions and OPEBs adopted by both the Federal Communications Commission (FCC) and the **[*6]** Federal Regulatory Commission (FERC).
. helps staff monitor OPEB costs by establishing additional reporting requirements, n6 and both requires implementation of cost containment measures for OPEB and allows for incentives if companies reduce annual costs.
. safeguards customers from inaccurate actuarials and health care cost assumptions, as well as reduced OPEB costs in the event a national health care program is implemented, by requiring utilities to defer the difference between actual costs and rate allowances for OPEB and dedicating OPEB allowances exclusively for that purpose.
. calls for re-examination in approximately 5-7 years of the accounting/ratemaking impacts on companies and the results of the Policy's provisions on pension and OPEB funding and expense levels.

n6 Along with other Annual Report changes for 1993, new schedules containing additional reporting requirements for pensions/OPEB will be considered at a later Commission session.

IV. RESPONSES TO THE NOTICE--SPECIFIC ISSUES
A. Use of SFAS No. 87 for Rate Purposes

All parties, except New Rochelle, agree that SFAS No. 87 should be adopted for rate purposes. n7 New Rochelle proposes that the tax contribution **[*7]** method be retained n8 and argues that, since it funds only the minimum required by ERISA n9 and IRS regulations, the amount is not excessive and its fund balance has not approached the Full Funding

Limitations established in the tax regulations.

n7 TDS Telecom (Edwards, Oriskany Falls & Port Byron Telephone Companies) noted that its employee pension plan is a defined contribution plan (DCP) and that this type of plan was not specifically addressed in the Notice. Although the Notice focused on defined benefit pension plans, it is also applicable to DCPs, as is the Policy adopted herein.
n8 Under this method the amount allowed in rates for pensions generally equals the amount the utility deposits in a dedicated external pension trust.
n9 Employee Retirement Income Security Act, enacted September 2, 1974.

SFAS No. 87 provides a more objective tool for measuring and evaluating pension expense than the current accounting method does. The tax contribution method espoused by New Rochelle is less desirable under current circumstances because the Federal Internal Revenue Code (IRC) specifies only the minimum and maximum amounts that must/may be funded. This standard is **[*8]** too broad and leaves the company with wide discretion as to the amount it will expense and fund. This situation is exacerbated by the fact that the IRC also allows actuaries to choose any one of several methods to determine the range of funding. As a result, the funding level calculated under the tax contribution method is extremely subjective.

SFAS No. 87 provides a superior method for quantifying and apportioning pension costs among current and future customers. Therefore, we adopt SFAS No. 87 for accounting and rate purposes, subject to the restrictions and other provisions described below and detailed in the attached Statement of Policy.

B. Rate Treatment for Prior Deferrals of SFAS No. 87 Amounts

By our September 22, 1987 order we directed all Class A and B utilities that adopt SFAS No. 87 before issuance of a final Statement of Policy to defer the difference between the allowance in current rates for pension costs and costs recorded according to SFAS No. 87, unless the change is made in the context of a rate proceeding. Several utilities request guidance as to how the balance of the deferrals created by that order will be treated for rate purposes.

The disposition **[*9]** of these deferrals will be determined on a case-by-case basis. Companies should propose a disposition of SFAS No. 87 amounts deferred in accordance with the September 22, 1987 order in the same rate filing in which they address recovery of the effects of adopting SFAS No. 106. n10 Companies that do not file for recovery of the costs covered by this Policy by June 1, 1995, must submit an accounting/ratemaking plan to the Commission proposing a disposition of these deferred SFAS No. 87 balances by September 1, 1995.

n10 This is addressed in Section III,C,2 of the attached Statement of Policy.

C. Use of SFAS No. 106 for Rate Purposes

All commenting utilities and the two CPA firms favor the adoption of SFAS No. 106 for rate purposes; however, the three Intervenor parties oppose its adoption. The major arguments in opposition are:

1. Pay-As-You-Go (PAYGO) is less costly than accrual accounting.
2. Adoption of SFAS No. 106 is not required by GAAP because SFAS No. 71 allows regulated utilities to use different accounting if the same treatment is followed for ratemaking.
3. The accrual approach will cause intergenerational inequity since customers will pay the costs of **[*10]** employees that are currently providing service and also

pay the costs of employees who provided services in the past.

1. *PAYGO is Less Costly* -- While the PAYGO approach may produce lower rates *in the short-run,* it creates offsetting long-term rate impacts. Continued use of PAYGO would inevitably result in future customers being required to bear a disproportionately high percentage of total costs.

The Intervenors' "present value" analyses are flawed because they contain inconsistent assumptions for the discount rates and fund earnings rates. These assumptions are critical because they help quantify future liabilities on the one hand and fund earnings on the other. These assumptions, as used in the SFAS No. 106 calculations, must be based on consistent and interrelated economic circumstances in order to produce valid results. When these components are made consistent and then applied to the PAYGO proponents' studies, the results show the total impact of PAYGO and accrual, in the long run, to be equivalent. Thus, taking into account the time value of money, accrual accounting (assuming funding) is no more costly than PAYGO in real terms. Further, accrual accounting (*i.e.,* **[*11]** SFAS No. 106) achieves an objective PAYGO cannot match -- it evens out OPEB costs over different periods of time and thus provides a fair and systematic cost allocation among current and future utility customers.

2. *SFAS No. 71 Permits Utilities to Stay on PAYGO* -- SFAS No. 71 n11 (paragraph 9), permits deferral of current expenses so long as there is a corresponding understanding and commitment by the regulator that the "regulatory asset" thus created has a reasonable probability of recovery in future rate allowances. The Intervenors recommend continued use of PAYGO for rates indefinitely and the establishment of a regulatory asset for all differences between the OPEB costs determined under PAYGO and SFAS No. 106.

n11 Statement of Financial Accounting Standards No. 71 -- "Accounting for the Effects of Certain Types of Regulation," issued in December 1982.

The issue of establishing a regulatory asset for the differences between SFAS No. 106 costs and PAYGO rate allowances was reviewed extensively by the EITF. n12 On January 21, 1993, the EITF reached a consensus agreement that

> "... a regulatory asset related to SFAS No. 106 costs should not be recovered by the regulator **[*12]** if the regulator continues to include OPEB costs in rates on a PAYGO basis."

n12 The Emerging Issues Task Force (EITF) of the FASB was formed in 1984 to provide timely financial accounting and reporting guidance on new, often narrow, business transactions. A consensus reached by the EITF is a source of GAAP.

Thus, the EITF rejected PAYGO as an acceptable treatment for rate regulated entities primarily because the regulatory body could not provide assurance the resulting long-term regulatory asset would actually be recovered in the future. The EITF also adopted several other provisions that apply only to rate-regulated entities for SFAS No. 106 costs. Our Statement of Policy complies with all provisions of the EITF's ruling.

3. *Intergenerational Equity* -- The inequity referred to by the Intervenors pertains to the

benefits earned in the past that have not yet been recognized or paid. The cost of these benefits is commonly referred to as "prior service costs." In accordance with one of the options in SFAS No. 106, the Notice proposes that this amount be amortized over a minimum of 20 years as part of the annual OPEB accruals.

The extent of the intergenerational inequity **[*13]** is overstated by the Intervenor parties since the majority of prior service costs are applicable to employees currently in, and expected to remain in, the companies' workforces for a number of years. The customers who will pay for the prior service costs, if SFAS No. 106 is used, are either the same customers who received the services of the employees to whom the liability relates, or are closer in time to when the service was rendered than future customers will be.

Conclusion -- SFAS No. 106 provides a superior method for quantifying and apportioning OPEB costs among current and future customers. We therefore adopt SFAS No. 106 for accounting and rate purposes, effective with this Order, and retroactive to January 1, 1993, subject to the restrictions and other provisions detailed in the attached Statement of Policy.

D. Phase-in Proposal -- OPEB

The two CPA firms strongly support the phase-in plan, characterizing it as a reasonable and practical approach to soften the rate impacts. Twelve utilities find the proposed phase-in acceptable. However, three of these utilities think the minimum rate of phase-in (.25 percent of operating revenues) is too low and/or the maximum **[*14]** length of the phase-in should be shortened to 4 years. NYT, on the other hand, expresses concern that the Notice's target rate of phase-in (*i.e.*, 1 percent of operating revenues) may be too large for some companies. NYT also proposes that, in order to maintain consistency, the phase-in should be at the incremental rate of 20 percent each year for 5 years.

Nine utilities oppose phasing-in the revenue requirement impact, reasoning that:

1. the phase-in violates the expense recognition required by SFAS No. 106;
2. a phase-in is unnecessary except in extreme cases;
3. staff's plan will leave the New York State utility industry in noncompliance with other states which adopt SFAS No. 106 without restrictions;
4. the required deferrals may never be recovered, especially in view of the increasing competitive nature of the electric, gas and telecommunications industries; and
5. the phase-in method is inherently arbitrary, subjective and does not allow a company's true cost to be reflected in its prices.

The three intervenor parties oppose the phase-in proposal consistent with their overall objectives to adopting SFAS No. 106 for rate purposes. MI also states that if SFAS No. **[*15]** 106 is adopted, the first part of the proposed phase-in should be accomplished over 10 years rather than the 5 years proposed in the Notice.

The significant rate impact caused by the adoption of SFAS No. 106 argues strongly for some form of phase-in plan. Moreover, the FASB, through the EITF, has decided that for rate regulated entities the additional cost of adopting SFAS No. 106 should be recognized in rates within about five years of the utility's adoption of SFAS No. 106, with any cost deferrals from the phase-in period being recovered within approximately 20 years from adoption of the Standard.

We concur with the Notice that a phase-in plan is needed to mitigate the impact on customer bills and to allow for a smooth transition from the PAYGO method. We adopt the phase-in plan proposed in the Notice with the modification that the maximum amortization period for the phase-in related deferrals will be extended from the proposed 10 years to the 20 years allowed by the EITF. n13

n13 The phase-in plan contained in the Notice predates the EITF's ruling.

Arguments that a phase-in plan for SFAS No. 106 is unnecessary, except in extreme cases, are unfounded. The plan calls for **[*16]** each utility's implementation of this Policy to be examined on a case-by-case basis. We may shorten or ignore the proposed phase-in if we conclude such action is appropriate given the circumstances of a particular utility, the impact on customers and rates, or other valid reasons. The case-by-case review also answers the concerns of those companies which criticized the rate of phase-in as either too fast or slow. We will base the phase-in within the revenue benchmark ranges proposed in the Notice on an as needed basis.

The argument that the proposed plan will result in inconsistencies among New York state utilities and between New York utilities and those of other states is incorrect given the EITF's ruling and the almost universal adoption of that accounting plan. Moreover, it is not uncommon to have a variety of rate plans, all slightly different, for similar items of expense (*e.g.*, Demand Side Management costs). Despite the varied ratemaking approaches we may apply, they are all implemented in accordance with our regulatory objectives and, in this instance, pension and OPEB rate elements will be guided by the detailed provisions of the Policy.

The concern that the pension **[*17]** and OPEB deferrals may never be recovered because of competition or deregulation is speculative at this time and for the near future. Moreover, under a deregulated framework, the recovery of such deferrals would be just one of many issues. Should be acquire the necessary legislative authority to deregulate an industry, or a portion thereof, we would review the proper rate treatment of all regulatory assets and liabilities in the context of a global deregulation plan.

Finally, claims that the deferral accounting is "arbitrary" and "subjective" are also misplaced. The deferrals in question are in strict compliance with the parameters outlined by the EITF and they constitute a reasonable ratemaking approach, considering the major rate impact OPEB poses.

E. Restriction on Selection of Options

SFAS Nos. 87 and 106 provide options that allow employers latitude when determining pension/OPEB costs. Staff thoroughly analyzed these options in order to determine how they could best meet our regulatory objectives and their recommendations were presented in the Notice. Most of the utilities and the CPA firms generally argue that the accounting standards should be adopted in their entirety **[*18]** and that the features embodied in the standards should be left exclusively to management.

It is clearly proper to limit the application of GAAP pronouncements in our ratemaking practices when they conflict with our regulatory objectives. In the instant case, some of the options available in the standards for calculating the level of component costs could produce results that would be contrary to our objectives of intergenerational equity and of mitigating rate impacts. Further, our restriction of these options for ratemaking purposes does not violate any provision of SFAS Nos. 87, 88 or 106.

The restriction that raised the strongest objection was the proposal to prohibit the use of the "corridor approach" to recognize certain pension/OPEB gains and losses. As a hedge against volatility in the year-over-year level of expense, both SFAS Nos. 87 and 106 allow employers the option to delay recognition of certain gains/losses. The *most conservative* method allowed by SFAS Nos. 87 and 106 for recognizing these delayed gains and losses, and the one universally adopted by New York utilities, is the "corridor approach." However, since companies may use any method of recognition that would **[*19]** cause a more rapid recognition of these gains and losses than would the corridor approach, employers have significant leeway in the period over which these gains and losses may be recognized.

The "corridor approach" allows employers to accumulate gains/losses until they reach a threshold; n14 once this level is reached, the amount *in excess* of this corridor is amortized over a period of approximately 20 years. The Notice proposed to prohibit the "corridor approach" and to require instead that the annual pension/OPEB expense calculation reflect a 10-year amortization of the total amount of gains and losses, without any threshold level.

n14 10 percent of the greater of (1) the market-related value of plan assets, or (2) the projected benefit obligation.

Commentors argue for retaining the "corridor approach" stating that it is a sound mechanism for mitigating the potential volatility in rates that could result from the SFAS Nos. 87 and 106 expense calculations and from the effects of stock market fluctuations on the value of pension and OPEB fund assets.

While extreme volatility of pension and OPEB expense is undesirable for rate purposes, using the "corridor approach" **[*20]** for recognizing gains/losses is an overly conservative mechanism that does not comport with our ratemaking objectives in this instance. n15 We therefore adopt the Notice's proposed 10-year amortization plan for gains/losses and reject the "corridor approach" for ratemaking purposes. n16 We will review this decision in the reexamination phase of this Policy, scheduled in 5-7 years. n17

n15 For example, Con Edison's 1991 corridor could contain a net gain or loss of $ 300 million.
n16 The Notice stated (Appendix A, page 18) that any gains or losses should be placed in a deferred account and amortized. This is incorrect. No deferral account should be used since the amounts will not yet have been recognized on the company's books. The Notice should have stated that 1/10th of the gains and losses should be recognized as part of the annual pension expense calculation. The unrecognized portion of these gains and losses will not be included in the rate base calculation.
n17 We agree with the Notice's recommendation to review the Policy after a reasonable period of time has elapsed and after all parties have gained sufficient experience. We conclude the review should be made in 5-7 years. **[*21]**

The 10-year amortization plan retains some of the averaging benefits of the "corridor approach," thereby reducing volatility, yet recognizes all gains and losses over a reasonable period of time. Additionally, the elimination of the corridor will not impose unwarranted burdens on companies, and we view the 10-year amortization plan as an improvement in the determination of pension and OPEB expense for rate purposes.

The Notice contains numerous technical provisions concerning the adoption and implementation into rates of SFAS Nos. 87, 88, and 106. We adopt all those provisions to the extent they are not modified by the following:

1. companies which initially adopt SFAS No. 87 on or after January 1, 1993 should amortize the transition asset/obligation over the period(s) specified in the Policy;
2. the Notice's proposal to *require* the use of a three year market-related value for valuing pension/OPEB plan assets is not adopted; and

3. companies which:

a. on the basis of an established history of amending their pension/OPEB plans, shorten the amortization period of prior service costs arising from plan amendments, or
b. change the method used to select an assumption or **[*22]** determine the value of plan assets or liabilities, or
c. select a different option, where there is a choice, must file notification with the Director of the Office of Accounting and Finance within 30 days of enacting the change(s). However, such notification is not necessary if the cumulative impact on pension and OPEB expense, when combined, is less than .05 percent of the company's common equity and less than $ 5 million.

F. Proposed Deferrals

Due to the unique nature of pension and OPEB costs, the Notice contains provisions requiring the use of deferral accounting procedures, at least through the 5-7 year review. The objectives of these provisions are to:

1. protect against inaccurate pension/OPEB projections until sufficient experience is gained to assure their accuracy, and
2. monitor pension/OPEB rate allowances that have yet to be paid out as benefits or deposited into an external pension/OPEB trust(s).

Several commentors question the propriety and need for deferral accounting, claiming pension/OPEB expense projections are no different than other expense forecasts used in setting rates. They also argue that, if deferral accounting must be adopted, rate **[*23]** base should be adjusted for the deferred balance, rather than accruing a noncash return, and such treatment should be applied equally to both negative and positive deferral balances.

Deferral accounting procedures are needed at least during the 5-7 n18 year review period to facilitate a smooth and complete implementation of the phase-in plan and to preserve the impact of the discontinuance of the "corridor approach." n19 Moreover, employers will be reviewing and revising pension/OPEB expense levels often for assumption changes, plan amendments and for the effects of implementing this Policy. Deferral accounting will mitigate the volatility in rate and expense differences during the transition period.

n18 The amount deferred during the 5-year phase-in, which constitutes the difference between the rate allowances and actual expense that has not been fully recovered, is likely to require deferral beyond the 5-7 year review period.
n19 This latter feature is especially important for companies which do not file rate proceedings as described in Section III,C,2 of the Policy Statement.

Finally, in the event a national health care program is implemented in the near future, **[*24]** OPEB rate allowances may be considerably different from actual costs; deferral accounting will buffer these differences and protect all parties from unforeseen consequences.

The amount of pension/OPEB rate allowances not deposited into an external fund (or paid out in benefits expense) will be accounted for using the internal reserve method. Some commentors argue that these amounts (net of their tax effect) should be deducted from rate base. As stated in the Notice, we considered applying rate base treatment for this item but opted for accruing a carrying charge. The carrying charge method matches the timing of the interest accrual on funds with the actual receipt/disbursement of those funds. The rate base method cannot provide this degree of accuracy because of regulatory lag. Moreover, complicated Internal Revenue Code provisions will determine the amount of pension/OPEB contributions that can legally be made to the external trust arrangements. The availability of cash and alternative investment opportunities will also affect the actual level of funding. Since the level of contributions may be difficult to predict during the implementation phase and thereafter, accruing a carrying-charge **[*25]** on the amounts *not* deposited into an external fund (or paid out in benefits expense) provides a more accurate method of compensating parties for the time value of money.

We do not expect companies to deposit in external funds more than they receive in rates. Therefore, the accrual of carrying-charges will be allowed only on credit balances in the pension and OPEB internal reserves. Companies seeking to accrue a carrying-charge on debit balances must petition for Commission authority or seek such approval in a rate proceeding.

G. Funding

The Notice proposed to require companies to deposit rate allowances for OPEB into tax-effective, external trust fund(s) to the maximum extent they so qualify. The Notice also listed three conditions that would have to be met for such contributions to be judged "tax-effective." Since there are currently few external trust fund arrangements for OPEB that qualify as "tax-effective," the Notice proposed that any portion of the OPEB rate allowance not deposited into "tax-effective" external funds would be retained by the company and could be used for regulated utility purposes. The amounts so retained would be accounted for as an internal reserve **[*26]** (similar to depreciation and decommissioning reserves).

About one-third of the commenting utilities objected to this requirement, claiming that it unnecessarily encumbered their flexibility to effectively manage their OPEB funding assets. Of particular concern was the effect this definition of "tax-effective" would have on their ability to fund the OPEB plans of management and other nonunion employees. The commentors claimed the requirement would preclude the use of VEBA trusts n20 for these employees since, unlike "collectively bargained" VEBAs, n21 the income earned on VEBA trusts for non-union and management employees is taxed when earned.

n20 Voluntary Employees' Benefit Association (VEBA) trusts are external OPEB trust funds for which cash contributions are tax deductible under Internal Revenue Code (IRC) Section 501 (c)(9). However, they must meet strict requirements specified in the IRC.
n21 VEBAs established for a company's current and retired employees who are employed (or were employed immediately before retiring) under a collectively bargained labor agreement.

The objective of prioritizing tax-effective funding was to obtain the most efficient funding vehicles **[*27]** available, not to bias OPEB funding of union employees over that of management or nonunion employees. In view of the limited number of tax-advantage vehicles available for funding OPEB, we are deleting two of the conditions listed in the Notice's definition of "tax-effective," as that term applies to OPEB funding, and retaining only the condition that contributions must qualify for a federal income tax deduction in the tax year the deposit is made.

The Notice proposed the same restrictions on pension fund contributions as those provided on OPEB contributions. However, for pensions, there are currently sufficient funding vehicles available that meet all three conditions in the Notice's definition of "tax-effective." Therefore, there is no need to revise this requirement for pensions.

H. Settlements and Curtailments

The Notice proposed several main provisions dealing with the settlement/curtailment of pension/OPEB plan benefits. The major provisions require companies to:

1. follow SFAS No. 88 and the applicable provisions of SFAS No. 106 to determine gains or losses from the settlement or curtailment of employee pension and OPEB plans and the granting of termination benefits; **[*28]**
2. notify the Director of the Office of Accounting and Finance prior to consummation of any such transaction(s);
3. defer all gains from settlements, curtailments, etc. on the utility's books for future Commission disposition; and
4. file a petition with the Commission if they wish to defer a loss for future rate recognition.

Most commentors either agreed or did not respond to these proposals. However, NYT argued for equal treatment for both gains and losses and noted that advance notification may not be feasible or practical as the transaction may be part of negotiations with employee labor unions. RTC argued that settlements only reduce the current pension or OPEB expense, not the ultimate liability.

Experience shows that settlements can reduce the ultimate pension/OPEB liability. n22 There will be instances where a settlement of all or part of the benefit plan is appropriate and others where it will not be. Utilities should periodically investigate the economic advantages of settling portions of their pension/OPEB liabilities.

n22 For example, in 1989 a jurisdictional company settled part of its pension plan by purchasing annuities. In doing so the company recognized a material gain and the company was no longer liable for the payment of pension benefits to the affected retirees. **[*29]**

In some situations it may not be possible for the utility to notify the Director of the Office of Accounting and Finance in advance of the transaction. Thus the written notification procedures are changed to "...filed within 30 days of the transaction."

The Notice's asymmetric treatment of gains and losses arising from pension/OPEB settlements/curtailments is appropriate because utilities have no incentive to defer gains since shareholders would be primary beneficiaries of such transactions. Moreover, pension fund assets have been funded primarily (if not exclusively) with ratepayer provided funds, and since large amounts of market and actuarial gains have been excluded from the pension expense calculations, it is equitable that pension gains realized from settlements/curtailments be preserved for ratepayers.

On the other hand, a company that incurs a loss in a settlement/curtailment transaction should be required to demonstrate how the transaction is in the ratepayers' interest. Having different accounting treatment for such gains and losses does not disadvantage companies; rather it adds a regulatory step to the approval process. However, such authorization will be considered **[*30]** only for material amounts and only if the company submits a petition within 60 days of the transaction proposing the accounting and ratemaking treatment to be applied to the net loss. n23 n23 The petition must contain a detailed derivation of the net loss, including the derivation of all of the annual costs and savings, both direct and indirect for both pensions of OPEB, related to, or generated by, the action that gave rise to the loss. Such amounts shall be quantified for the period of time commencing with the inception of the action or incident and ending with the projected date of company's next rate change.

I. Early Retirement Savings

Early retirement programs allow utilities to trim their labor force and to reduce payroll costs. Among other things, however, these programs shift the cost of providing fringe benefits for the early retiree from a current operating cost to the OPEB fund. In the current ratemaking process, companies retain the savings from avoided salaries/wages and fringe benefits until the next rate proceeding. Meanwhile, increased annual pension and OPEB costs are thrust upon future customers.

The Notice tried to correct for this cost shifting by **[*31]** requiring companies to defer the savings from avoided fringe benefit costs related to the early retirees until the early retirements have been recognized in rates. n24 The captured savings would be used to help defray the related OPEB costs which commence being paid from the OPED fund(s) immediately upon the employee's retirement. However, in order to prevent establishing a disincentive to this type of cost containment program, the Notice did not target wage and salary savings for capture. Several utilities misunderstood this and thought we were proposing to capture all of the savings while not providing for recovery of the associated costs. n24

n24 Notice, page 5.

In instances where the company is not requesting to defer for subsequent recovery the costs it has/will incur as a result of a broad based early retirement program, the capture of the limited amount of savings, as proposed, is appropriate. n25 However, since broad based early retirement programs may give rise to a loss in the short-term, but over the long-term result in a significant net savings, the company may wish to seek deferral and subsequent recovery of its costs. In instances where the early retirement program **[*32]** can be shown to be in the best interests of the ratepayers, companies may petition for recovery of significant program costs. Upon petition, early retirement amounts (both costs and savings) will be accorded appropriate deferral accounting treatment, with recovery decided in subsequent proceedings pursuant to our conventional standards of prudence. n26

n25 The "savings" subject to this capture shall be an amount equal to the revenue requirement reduction applicable to the OPEB (*i.e.*, health care coverage, life insurance, and prescription drug plan(s), etc.) of those employees electing early retirement.
n26 *See* Case 90-E-0775, *Consolidated Edison Company of N.Y., Inc., et al., Order Accepting Contracts for Filing and Denying Petition* (Issued December 10, 1990), p. 8; Case 27563, *Long Island Lighting Company, Opinion and Order Determining Prudent Costs,* Opinion No. 85-23 (Issued December 16, 1985).

Such petitions are to be filed with the Commission within 60 days of the consummation of the transaction and must demonstrate the transaction is in the ratepayers' best interests. The petition should quantify all costs and savings (both direct and indirect) to **[*33]** be incurred/realized as a result of the early retirement program from its inception to the projected effective date of the company's next rate change; or beyond that date if ratepayers are receiving long-term benefits from the action. Such petition may include a proposal for the sharing of the net savings resulting from the early retirement program.

J. Use of Pension Surpluses to Offset OPEB Expenses

Jurisdictional utilities were requested to comment on the feasibility of using excess pension fund assets that may exist to mitigate the rate impact of adopting SFAS No. 106. Fifteen utilities, plus CPB and MI, responded.

The responding utilities oppose the use of pension assets to fund OPEB, contending the pension liability is continuous and that all money in the fund must be used for pension purposes. They claim the proposal would merely result in the transfer of assets from pensions to other employee benefit costs and will not produce any long-term benefit. They infer that the proposal is an attempt to avoid, or artificially reduce, rate allowances for OPEB. They also pointed out, as did the Notice, that the legal restrictions associated with pension funds withdrawals, VEBAs, **[*34]** and Section 401(h) transfers may encumber the use of pension funds for OPEB purposes. n27

n27 Like VEBA's, Section 401(h) transfers are one of the few types of tax deductible vehicles available, but they also are subject to strict federal requirements.

CPB proposes that excess pension assets be used to reduce rates rather than being shifted to cover "highly uncertain OPEB costs." MI supports the concept of using excess pension assets for OPEB but argues that SFAS No. 106 should not be used for rate purposes.

Reducing the long-run cost of employee benefits is not the intent behind the proposal to transfer excess pension funds to OPEB (where a transfer is both practical and legally permissible). Nor is the intent of the proposal to ignore OPEB in rates. Rather, it is intended to strike some balance between a retiree benefit fund that is overfunded and a retiree benefit fund that is dramatically underfunded. Because the pension funds of some of our jurisdictional companies are considerably in excess of their current accumulated obligations, it is logical to apportion some of this excess to OPEB, if possible.

In the first rate filing submitted after this Policy is issued, jurisdictional **[*35]** companies should describe their efforts to allocate pension plan assets in excess of pension benefits obligations to tax-effectively fund SFAS No. 106 related liabilities. The filings are to include all particulars related to such assignments, such as amounts, dates, investment vehicles used, tax effects, etc. Companies electing not to assign excess pension plan assets are to provide a complete explanation of this decision in the rate proceeding wherein they implement the provisions of this Policy. n28

n28 Due to strict federal requirements covering these vehicles and options, they may not be a reasonable option for a particular utility. Thus, we are not requiring they be made but they must be given consideration.

K. Implementation Plans -- Rate Recovery

The Notice provided several methods whereby companies could file to implement the Statement of Policy in rates. There were no comments opposing the implementation methods proposed. However, the date for filing the implementation plan is modified, and another modification is necessary for situations where companies will not be filing for a rate change by the terminal date(s) established by the Policy.

The date for submitting **[*36]** an implementation plan is changed from "the date SFAS No. 106 is adopted" to "June 1, 1995" for companies which must adopt SFAS No. 106 in 1993. This change provides time for companies to develop a well conceived ratemaking plan and to gather employee actuarial and demographic data. n29 Although the deadline for filing a rate plan is extended, the deferral and carrying-charge requirements described in the Policy must be applied for regulatory accounting purposes commencing January 1, 1993 n30 (January 1, 1995 for companies that meet the requirements for the delayed implementation).

n29 This will leave approximately 3 years to effectuate the OPEB phase-in.
n30 Some companies adopted SFAS No. 87 for regulatory accounting purposes prior to January 1, 1993 in accordance with our September 22, 1987 order. Deferrals made prior to January 1, 1993 in accordance with that order are to remain segregated from deferrals made in accordance with this Policy. If this previous deferral, net of any portion which has been accorded rate base treatment, has a credit balance, a carrying-charge shall be accrued on the net balance at a rate, and in the manner, described in Section III,A,7 of the Policy. If the net balance is a debit amount, no interest shall be accrued.

For companies which keep their books and records on a fiscal year basis, these deferral and carrying-charge accrual requirements, as they apply to OPEB, are effective commencing with the company's first fiscal year beginning after December 15, 1992. **[*37]**

Companies with pending rate proceedings may amend their filings to include the effects of implementing the provisions of this new Statement of Policy no later than filing of Briefs on Exception.

Single-issue rate filings for the purposes of implementing SFAS No. 106 will not be accepted. Companies which are not required to adopt SFAS No. 106 until fiscal years beginning after December 15, 1994 will have until January 1, 1996 to file a rate and accounting plan.

If a company does not file for a rate change within the time limits specified in the Statement of Policy, the company shall cease to qualify for recording a regulatory asset for the impact of SFAS No. 106. In such a case, all deferrals of SFAS No. 106 costs that have been established in anticipation of rate recovery are to be charged to current period income by the end of the latest authorized filing period.

L. Actions to Control OPEB Costs

The Notice proposed that all utilities be required to take certain actions to control OPEB costs. Most of the responding utilities indicated they have been taking the actions outlined and that no further requirements need to be imposed. Some company commentors believe the decision **[*38]** to initiate cost reductions in their OPEB programs should be left to management and should not be directed by the Commission.

The recommendations contained in the Notice do not force companies to implement any particular action or meddle in management prerogatives. All utilities, including those that adopt SFAS No. 106 without requesting rate treatment, are to demonstrate in their first rate case following adoption of SFAS No. 106 that they have taken the actions to control OPEB that are listed in Section III,C,4 of the Policy.

M. OPEB Cost Control Incentives

Utilities normally have a financial incentive to control costs between rate changes because they are allowed to retain some/all of the savings achieved beyond the rate allowance granted for the costs. However, the deferral mechanisms adopted herein, although necessary under the circumstances, will capture any efficiencies gained through effective management of the program. Since OPEB is a significant expense, utilities should have incentives to minimize program costs consistent with workforce morale and productivity objectives.

The specific incentives will be based on results that can be clearly demonstrated and supported **[*39]** and on the following considerations: the level of effort involved, ingenuity shown, the long-term nature of the savings, the amount of the annual savings achieved relative to the annual cost, and other pertinent factors identified by the utilities.

N. Plans Which Cover More Than Jurisdictional Utility Employees

Many consolidated corporate structures cause jurisdictional companies' employees to be participants in pension/OPEB plans that cover regulated, non-regulated, and/or out-of-state employees. n31 The diverse population covered by these consolidated plans and the multi-jurisdictional arenas with their multiple regulatory or statutory requirements could cause administrative problems, if the various authorities have inconsistent standards. Because the Notice proposed restrictions on certain SFAS No. 87 and SFAS No. 106 provisions for ratemaking purposes, some respondents with consolidated employee benefit plans claim this would cause a need for additional accounting records and actuarial studies. This, they argue, would increase costs ultimately borne by New York ratepayers. They propose, instead, that SFAS Nos. 87, 88, and 106 be adopted without any restrictions.

n31 Jurisdictional utilities in this category include Central Hudson, O&R, NFG, Alltel, AT&T-NY, GTE New York, TDS TELECOM, NYSTA, NYT, RTC, Jamaica, Long Island Water, New Rochelle, NY-American and Spring Valley. **[*40]**

Our accounting and ratemaking decisions strive to avoid duplicate or unnecessary recordkeeping and to minimize ratemaking conflicts with other authorities that have complementary responsibilities. In this instance some conflict appears unavoidable because of the competing interests involved and what may be different price setting philosophies. To achieve the regulatory objectives outlined herein, the commentors' proposal to eliminate all restrictions is rejected. However, if a jurisdictional company which participates in a consolidated group pension/OPEB plan with non-jurisdictional affiliates can demonstrate severe hardship or inequity as a direct result of our Statement of Policy, we will consider a waiver of the identified, onerous provision(s). Any such filing must clearly explain the conflict, justify the exemption sought, and provide an alternative proposal that *clearly* satisfies the objectives of the Statement of Policy. n32

n32 On December 18, 1992 New York Telephone Company (NYT) filed an accounting plan that included full adoption of SFAS Nos. 87, 88 and 106. We will address this request in a separate proceeding. In the interim, NYT may record its pension and OPEB costs in accordance with the provisions of its proposed plan, subject to future reversal and reconciliation, and in accord with our final decision in that proceeding.

AT&T Communications of New York, Inc. may request exemption because it is subject to a reduced form of regulation. However, it must request for exemption from the specific provisions it believes are not applicable. **[*41]**

In a related matter, the Notice proposed prohibiting the commingling of OPEB monies provided by New York State ratepayers with funds from other affiliates in a consolidated group. This segregation of New York funds is intended to provide added protection from non-jurisdictional affiliates realizing any financial or other advantage from the steady flow and availability of ratepayer money. n33

n33 Consolidated pension plans and pension funds already exist and therefore cannot be treated similarly without substantial administrative and Treasury Department complications. Therefore, existing pension funds are exempt from this prohibition on commingling.

Accordingly, all funds granted for SFAS No. 106 costs, plus any pension related or other funds or credits the company transfers or is otherwise directed to use for OPEB purposes, are to be used exclusively for the payment of trustee fees, associated income taxes (if any), and for the cost of postretirement benefits paid to or for employees who have worked at and for the jurisdictional company for the qualifying period(s) and under the qualifying conditions. When an external fund is established for the deposit of these funds, no **[*42]** corporation, affiliate, subsidiary, partnership, etc. other than the jurisdictional company is to be allowed to have control over, access to, or the authority to withdraw funds from such account.

CONCLUSION

SFAS Nos. 87, 88 and 106 provide a superior method for determining pension and OPEB expense for rate purposes. For the most part our accounting and ratemaking objectives are compatible with those of the FASB. However, certain restrictions need to be applied to the newly adopted Accounting Statements so that their implementation in rates meets our regulatory objectives. Also, many difficult assumptions and subjective estimates are necessitated by the Statements. Thus, full deferral of rate allowance variations is being instituted to protect companies and ratepayers from potential volatility, at least until the 5-7 year review is completed.

Since the impact of SFAS No. 106 on rates will be material, we are adopting various rate mechanisms, including a phase-in plan and the use of excess pension fund assets, to temper its impact. Finally, utilities should strive to control their OPEB costs to the greatest extent possible. To encourage cost containment we have outlined a plan that **[*43]** allows companies to share in the savings realized for such efforts.

The Commission Orders:

1. The attached Statement of Policy concerning the accounting and ratemaking treatment for pensions and postretirement benefits other than pensions is adopted for all jurisdictional utilities that are subject to the Uniform System of Accounts, effective with this Order, and retroactive to January 1, 1993.

2. This proceeding is continued.

By the Commission

APPENDIX A

STATEMENT OF POLICY CONCERNING THE ACCOUNTING AND RATEMAKING TREATMENT FOR PENSIONS AND POSTRETIREMENT BENEFITS OTHER THAN PENSIONS

I. Introduction

This Statement of Policy is provided to efficiently and effectively implement our new policy for the accounting and rate treatment for pensions and postretirement benefits other than pensions (OPEBs). Our new policy is rooted in the following three interrelated pronouncements issued by the Financial Accounting Standards Board.

. Statement of Financial Accounting Standards (SFAS) No. 87 -- "Employers' Accounting for Pensions"
. SFAS No. 88 -- "Employers' Accounting for Settlement and Curtailments of Defined Benefits Pension Plans and for Termination Benefits"
. SFAS **[*44]** No. 106 -- "Employers' Accounting for Postretirement Benefits Other Than Pensions"

This Statement of Policy (Policy) shall be followed in all instances unless particular circumstances demonstrate it to be inappropriate. However, before special treatment will be granted, a utility must make a strong and clear showing why the Policy should not apply in its particular case and/or how it would cause undue financial or operational harm if adhered to.

Due to the unique nature of the subject matter, the results of this Policy will be reviewed in five to seven years. Jurisdictional utilities and other interested parties will be invited to participate and provide staff with any relevant information and comments.

II. General Policy

SFAS Nos. 87, 88, and 106, subject to certain restrictions, shall be used for accounting and ratemaking purposes for all applicable transactions as of January 1, 1993. n1 For SFAS No. 106 this effective date applies only to employers who have more than 500 benefit plan participants in the aggregate, or are public enterprises. n2 Absent special permission, all other entities shall not use SFAS No. 106 until fiscal years beginning after December 15, 1994.

[*45]

n1 For companies which keep their regulatory books and records on a fiscal year basis, the applicable date, as it applies to SFAS No. 106, shall be the beginning of the company's first fiscal year beginning after December 15, 1992. For SFAS Nos. 87 and 88, the date will remain January 1, 1993.
n2 A public enterprise is defined in SFAS No. 87 as an enterprise (a) whose debt or equity securities are traded in a public market, either on a stock exchange or in the over-the-counter market (including securities quoted only locally or regionally), or (b) whose financial statements are filed with a regulatory agency in preparation for the sale of any class of securities.

III. Provisions

A. Pensions

1. Unless otherwise provided, the provisions of this Policy for pensions shall be reflected in rates at the same time as the provisions for OPEB are reflected in rates. The requirements for OPEB are provided below.
2. Commencing January 1, 1993, companies shall defer the difference between 1) the rate allowances n3 for pensions, less any pension rate allowance the company is directed to use for OPEB purposes, and 2) pension expense determined as required by this Statement **[*46]** of Policy. n4
3. Companies which initially adopt SFAS No. 87 on or after January 1, 1993, are to amortize the transition amount over the average remaining service period of its employees, or 15 years, whichever is longer. n5

4. Commencing January 1, 1993, all companies are to recognize, as part of their SFAS No. 87 expense calculation, all gains or losses described in Paragraph 29 of SFAS No. 87, except those not yet reflected in the market-related value of plan assets (if the company uses that method to value plan assets), over a 10-year period calculated on a vintage year basis. For those companies which have already adopted SFAS No. 87 for regulatory accounting and ratemaking purposes, these gains or losses accumulated and unrecognized as of January 1, 1993 are to be considered one vintage year.
5. By Order dated September 22, 1987, we authorized utilities to adopt SFAS No. 87 before the effective date of this Policy if the accounting change was made in the context of a rate proceeding or if the company deferred the impact of the change. Companies are to propose a disposition of SFAS No. 87 amounts deferred in accordance with the 1987 Order in the same rate filing in which they **[*47]** address recovery of the effects of adopting SFAS No. 106. n6 Companies which do not file for recovery of the costs covered by this Policy by June 1, 1995, must submit an accounting/ratemaking plan to the Commission proposing a disposition of these deferred SFAS No. 87 balances by September 1, 1995.

Deferrals made prior to January 1, 1993 in accordance with our September 22, 1987 order are to remain segregated from deferrals made in accordance with Sections III,A,2 and III,A,7 herein. If the deferral made in accordance with the September 22, 1987 order, net of any portion which has been accorded rate base treatment in a rate proceeding, has a credit balance, interest shall be accrued on that net balance at a rate, and in the manner, described in Section III,A,7 herein. If the net balance is a debit amount no interest shall be accrued.
6. Starting with the company's first proceeding in which SFAS No. 106 is considered for rates, the company must report on its efforts to allocate pension plan assets in excess of pension benefit obligations to fund OPEB related liabilities on a tax-effective basis. n7 This must include all particulars related to such assignments including, but not limited **[*48]** to, amounts, dates, investment vehicles used, tax effects, etc. Companies electing not to assign excess pension plan assets must provide a complete explanation of such decisions. All subsequent rate filings shall update this data, until the requirement is rescinded by the Director of the Office of Accounting and Finance either on a case-by-case or generic basis.
7. All companies shall make maximum use of tax-effective external funding vehicles for deposits of pension funds. n8 Commencing January 1, 1993, an amount of the recorded pension liability equivalent to the following shall be classified as (transferred to) an internal reserve account: n9
1. the pension rate allowance, n10 plus
2. the actual amount of pension costs that are charged to construction, n11 less
3. any pension related funds or credits the company is directed to use for OPEB purposes.

The funds represented by the internal reserve may be commingled with other utility funds and used for regulated utility purposes until such time as the funds are used for payment of pension benefits deposited into an external pension trust(s), or the Commission orders some other disposition.

For rate purposes, the pension internal **[*49]** reserve shall not be used to reduce rate base unless otherwise directed by the Commission. n12 Instead, interest is to be accrued monthly on amounts recorded in the reserve (net of its tax effects) at the company's latest authorized pretax rate of return. Such interest shall be recorded in a separate subaccount in the internal reserve and interest shall be compounded thereon n13 on a monthly basis using the same pretax rate of return. If the cumulative net-of-tax balance in this reserve (including accrued interest) is a debit, no accrual of interest is to be made for that month. n14 Companies shall apply deferred income tax accounting for the difference between book and tax treatment of SFAS No. 87 costs, in accordance with the Commission's Statement of Policy on SFAS No. 109. n15

8. The assumed discount rate used to determine pension and OPEB expense must be based on the rates of return currently available on high-quality bonds, and other market indicators which are of similar duration and risk, whose cash flows match the timing and amount of the expected benefit payments. If settlement of the obligation with a third-party insurer is possible, the rate of return inherent in the **[*50]** amount at which the obligation can be settled is relevant in determining the discount rate, but should not be a major factor unless settlement is imminent.

9. If a company shortens the amortization period for prior years service costs based on the contention that "it has a history of plan amendments," it must file notification with the Director of the Office of Accounting and Finance within 30 days of enacting the change(s). However, such notification is not necessary if the cumulative impact on annual pension and OPEB expense, when combined, is less than 0.05 percent of the company's common equity and less than $ 5 million.

10. If a utility 1) changes the method or manner in which it selects an assumption or determines the value of plan assets or liabilities or 2) selects a different option, where there is a choice, it is not an accounting change subject to Section 48 of the Commission's Rules of Procedure. However, it must file a notification with the Director of the Office of Accounting and Finance explaining the particulars within 30 days of enacting the change(s) if the cumulative impact on annual pension and OPEB expense, when combined, is 0.05 percent of the company's equity **[*51]** or $ 5 million, whichever is less.

B. SFAS No. 88 -- Settlements/Curtailments/Terminations & Termination Benefits

1. If a company settles, curtails, or terminates an employee pension plan, it is to notify the Director of the Office of Accounting and Finance in writing within 30 days of the transaction. The written notice is to provide a full explanation and justification for the transaction and an estimate of its rate effects.

2. SFAS No. 88 will be used to compute the gain or loss from all transactions covered by that statement. Companies are required to

defer, for Commission disposition, any gains related to the settlement or curtailment of pension benefits and the termination of pension plans. Within 30 days of the completion of such transactions, companies must file with the Commission for disposition of such gains in the same manner as prescribed for Pension Costs in Section III,B,1 above.

Any losses incurred due to the settlement/curtailment of pension benefits and terminated pension plans, or the granting or provision of special or contractual termination benefits, are not deferrable or recoverable in rates without Commission authorization. Granting of such authorization **[*52]** will be considered only for material amounts and only if the company files with the Commission a petition requesting such authorization within 60 days of the transaction. Such petition shall propose the accounting and ratemaking treatment to be applied to the net loss. The petition must fully support the quantification and derivation of all of the annual costs and savings, both direct and indirect for both pensions and OPEB, related to, or generated by, the action(s) that gave rise to the loss. Such amounts shall be quantified for the period of time commencing with the inception of the action or incident, and ending with the projected date of the company's next rate change.

3. The granting of a broad based early retirement program may give rise to a loss in the short-term, but over the long-term result in significant net savings. In such instances companies may petition, as described immediately above, for recovery of significant program costs. Upon petition, early retirement amounts (both costs and savings) will be accorded appropriate deferral accounting treatment, with recovery decided in subsequent proceedings pursuant to our conventional standards of prudence. n16

Any such **[*53]** petition must demonstrate the transaction is in the best interests of ratepayers and must fully support the quantification and derivation of all of the annual costs and savings, both direct and indirect, for both pensions and OPEB, to be incurred/realized as a result of the early retirement program from its inception to the projected date of company's next rate change filing; and permissible beyond if ratepayers are receiving long-term benefits from the action. Such petition may include a proposal for the sharing of the net savings resulting from the early retirement program.

C. OPEB

1. Phase-in

a. The full annual level of prudently incurred OPEB expense will be recognized in rates using SFAS No. 106 within approximately five years from the date of adoption of SFAS No. 106 for accounting purposes. The rate phase-in may take place in steps.

b. Differences between 1) the rate allowance n17 for OPEB expense, plus any pension related or other funds or credits the company is directed to use for OPEB purposes, and 2) OPEB expense determined as required herein, may be deferred for future recovery. n18 These deferrals shall be recovered within approximately 20 years of the

date SFAS **[*54]** No. 106 is adopted for accounting purposes.
c. The percentage increase in rates scheduled under this recovery plan for each future year shall be no greater than the percentage increase in rates scheduled under the plan for each immediately preceding year. A recovery plan based on a straight-line basis phase-in may be allowed.
d. For regulatory accounting and ratemaking purposes, the transition obligation must be amortized over the company's employees' average remaining service period, or 20 years, whichever is longer.
e. All companies are to recognize, as part of their SFAS No. 106 expense calculation, all gains or losses described in Paragraph 56 of SFAS No. 106, except those not yet reflected in the market-related value of plan assets (if the company uses that method to value plan assets), over a 10-year period calculated on a vintage year basis. This method for recognizing gains and losses shall be effective at the date SFAS No. 106 is adopted for accounting purposes.
2. Rate Recovery
a. Companies with rate proceedings pending should amend such filings to include the effects of implementing the provisions of this Statement of Policy prior to the filing of Briefs on Exceptions. **[*55]**
b. Companies may reflect the impact of this Statement of Policy in staged rate filings already approved by the Commission.
c. Companies not covered by paragraphs 2.a. or 2.b. immediately above have until June 1, 1995 to file with the Commission rate changes to recover the effects of adopting SFAS No. 106 and SFAS No. 87 n19 (if not already adopted). Such filings shall encompass a general rate change whereby all elements of cost are presented and considered. Single-issue rate filings for the purposes of implementing SFAS No. 106 into rates shall not be accepted. Companies that are not required to adopt SFAS No. 106 until fiscal years beginning after December 15, 1994 have one year from that effective date to file such rate plans.
d. If a company does not reflect the provisions of this Statement of Policy in rates within the guidelines provided in Sections III,C,2,a, b, and c above, it no longer qualifies for recording an OPEB related regulatory asset as allowed by Sections III,C,1,b and III,C,2.e.

Accumulated balances of deferred SFAS No. 106 costs on the books of companies which fail to meet the above prescribed filing requirements must be written-off by a charge to the income **[*56]** statement by the end of the latest of these allowed filing periods and no future OPEB costs may be recovered as regulatory assets until the company comes into compliance with the filing requirements or special permission is granted.
e. If there is no phase-in of SFAS No. 106 costs, or the phase-in is completed, the difference between 1) the rate allowance for OPEB, plus any pension related to other funds or credits the company is directed or use for OPEB purposes, and 2) the actual OPEB expense determined as required herein (less related productivity adjustments, disallowances, incentives, etc.) shall be deferred in a separate account. n20 Future disposition of such amounts will be at the discretion of the Commission.
f. If a company shortens the amortization period for prior years service costs based on the contention that "it has a history of plan amendments," it must file notification with the Director of the Office of Accounting and Finance explaining all the particulars within 30

days of enacting the change(s). However, such notification is not necessary if the cumulative impact on annual pension and OPEB expense, when combined, is less than 0.05 percent of the company's common **[*57]** equity and less than $ 5 million.
g. If a utility 1) changes the method or manner in which it selects an assumption or determines the value of plan assets or liabilities or 2) selects a different option, where there is a choice, it is not an accounting change subject to Section 48 of the Commission's Rules of Procedure. However, it must be reported to the Director of the Office of Accounting and Finance within 30 days of enacting the change(s) if the cumulative impact on annual pension and OPEB expense, when combined (if similar or related changes are applicable to both), is 0.05 percent of the company's common equity or $ 5 million, whichever is less.

3. Funding

a. External Funding
(1) Companies are required to make the maximum use of tax-effective funding vehicles n21 for rate allowances n22 received for OPEB unless such funding is economically unjustified in view of factors *other than* the difference in earnings rates for the internal reserve vs. the external trust. Deposits to such trust(s) shall be made no less than quarterly, in amounts that are proportional, and on an annual basis equal, to the annual test period allowances that qualify for tax-effective deposits. **[*58]**

The trust must provide that any disbursements are limited to 1) the cost of postretirement benefits paid to, or for, employees who have worked at and for the jurisdictional company for the qualifying period (s) and under the qualifying conditions and 2) payments for expenses of the trust. n23 The trustee must be independent of the company and authorized to make only those investments that are consistent with sound investment policies for trusts of this nature.
(2) For all external OPEB trusts, no corporation, affiliate, subsidiary, partnership, etc., other than the jurisdictional company shall have control over, access to, or the authority to withdraw funds from such account.
(3) Companies must establish OPEB plans separate from other corporations', affiliates', subsidiaries', partnerships', etc., plan(s), if such separation is necessary to adhere to the provisions of Sections III,C,3,a,(1) and/or III,C,3,a,(2) above and to qualify for income tax deductions or other tax advantages authorized for, or available to, similar qualified external trust arrangements.
b. Internal Funding
(1) Commencing January 1, 1993, n24 an amount of the recorded OPEB liability equivalent to the following **[*59]** shall be classified as (transferred to) an internal reserve account: n25
1. the OPEB rate allowance, n26 plus
2. the actual amount of OPEB costs that are charged to construction, n27 plus
3. any pension related or other funds or credits the company is directed to use for OPEB purposes.

The funds represented by the internal reserve may be commingled with other utility funds and used for regulated utility purposes until such time as the funds are used for payment of OPEB benefits, deposited into an external OPEB trust(s), or the Commission orders some other disposition.

For rate purposes, the OPEB internal reserve shall not be used to reduce rate base unless otherwise directed by the Commission. n28 Instead, interest is to be accrued monthly on amounts recorded in the reserve (net of its tax effects) at the company's latest authorized pretax rate of return. Such interest shall be recorded in a separate subaccount in the internal reserve and interest shall be compounded thereon n29 on a monthly basis using the same pretax rate of return. If the cumulative net-of-tax balance in this reserve (including accrued interest) is a debit, no accrual of interest is to be made for that month. **[*60]** n30 Companies shall apply deferred income tax accounting for the difference between book and tax treatment of SFAS No. 106 costs, in accordance with the Commission's Statement of Policy on SFAS No. 109. n31

(2) Should circumstances change and additional tax-effective external funding vehicles become available or economically justified, companies may deposit amounts represented by the internal reserve, including accrued interest, into such arrangements without Commission approval. A complete explanation of such transactions shall be reported to the Director of the Office of Accounting and Finance within 30 days of such transfer. The external trust and any funds deposited into that trust must meet the requirements described herein.

(3) If a company or its parent (if an affiliate) institutes a broad based early retirement program, the jurisdictional company's revenue requirement reductions (net of associated increases to retiree costs) applicable to the health care coverage, life insurance, and prescription drug plan(s) of those employees electing early retirement shall be credited to a separate subaccount of the OPEB Internal Reserve Account. n32 This accounting shall commence when **[*61]** the early retirees become eligible to receive benefits from the company's postretirement benefit plan(s), shall be recorded monthly, and shall end when the savings resulting from the early retirement program are recognized in rates or otherwise disposed of by the Commission. Interest shall be accrued monthly and in the same manner, and at the same rate, as is done for the rest of the internal fund. Deferred tax accounting shall apply, as necessary. Recovery of the costs associated with early retirement programs is addressed in Section III,D below.

4. Rate Case Documentation and Minimum Cost Control Requirements

At a minimum, companies must establish a continuing program to analyze, at least annually, the feasibility of changes to plan benefits, plan design, plan administration, funding, computer and claims processing systems, and other appropriate areas to reduce the overall cost of OPEB benefits. In *every* rate change proceeding, and for each OPEB plan, the company must report the status of its program, the initiatives considered and rejected, and the initiatives taken, to reduce/control costs since its last rate proceeding. Estimates of the effects of these initiatives **[*62]** (both those taken and those rejected) on the overall cost of the plan(s), the annual cost benefits, and impacts on current revenue requirement must be provided. A detailed description of any plan amendments, with estimates of their rate impact(s), must also provide:

In the first rate proceeding filed following the issuance of this Statement of Policy, companies must provide:
a. a complete description of the features and provisions of the postretirement benefits plans other than pensions, such as the benefits covered, deductibles, co-pay provisions, threshold/limitations, eligible participants in addition to the retiree, etc.
b. the formal written provisions of the plan(s) as they are established in the official corporate rules, regulations, employee collective bargaining agreements, employee pension/welfare pamphlets distributed describing such benefits, etc.
c. an analysis clearly showing how the company's postretirement plan (s) compare with those of other New York State utilities and at least three non-regulated enterprises' plans with regards to features, benefits, cost per employee, cost per benefit, total transition obligation, service costs, number of employees covered by **[*63]** the plans, and number of retirees covered by the plans.

If this analysis shows that the subject utility's plan(s) is more costly than those of the other employers shown, a detailed explanation must be provided explaining the difference and substantiating why the costlier benefits are justified.
d. An analysis clearly showing that the company's retiree benefit plan (s) are part of a comprehensive employee compensation and benefit package that is reasonable and necessary to attract and maintain a reliable and competent workforce.

5. Cost Control Incentives

As this policy requires deferral of all differences between actual OPEB costs and associated rate allowances (at least during the period of review), any savings the company may achieve through its cost control efforts are automatically captured for ratepayers. To provide a financial incentive to minimize OPEB costs, we will consider allowing companies to retain a portion of actual savings achieved from non-mandated OPEB cost control measures. Accordingly, before the Commission rules on the review of this Policy in about 5-7 years, utilities may propose an incentive arrangement consistent with productivity and workforce morale **[*64]** objectives. Such requests, which preferably should be made within the context of a rate proceeding, must include a complete description of the actions implemented, as well as a clear demonstration that savings have actually resulted at the claimed level. Additionally, it must be shown the action will have long term effects.

Proposals to share in the savings of future cost-containment actions may be made. However, substantial evidence and assurance must be provided that substantiate the savings will actually materialize. Incentives will not be granted when savings result from the mere trade-off of OPEB benefits for other employee compensation or fringe benefits.

D. SFAS No. 106 -- Settlements/Curtailments/Terminations & Termination Benefits

Companies shall follow the appropriate provisions of SFAS No. 106 to determine gains and/or losses resulting from settling, curtailing, or terminating an OPEB plan or the granting, or provision, of special or contractual termination benefits. All notification, deferral, and petition requirements specified in Section III,B herein as being applicable to SFAS No. 88 transactions and broad based early retirement programs are also applicable **[*65]** to the comparable OPEB transactions. n33

n3 For the purpose of determining the level of deferrals required by this Statement of Policy for both pensions and OPEB, "rate allowance" for electric, gas and water companies shall be calculated by the following formula:

projected expense allowed in last rate proceeding X actual sales projected sales (*e.g.* Kwh, Therm, or Gallons)

For telephone companies it shall be the amount allowed in the company's last rate proceeding.

n4 For the purpose of calculating this deferral, both the "rate allowance" and "pension expense" shall only include the amount charged to expense accounts (*i.e.,* not charged to construction, depreciation expense and rate base allowance related to capitalized pension costs.)

n5 The "transition amount" is the unrecognized net asset or obligation at the date SFAS No. 87 is adopted.

n6 This is addressed in Section III,C,2.

n7 The prescribed procedures for implementing SFAS No. 106 into rates are described below.

n8 For the purpose of this Policy, "tax-effective funding vehicle" for pensions is defined as an externally held pension dedicated account or trust arrangement (trust) that: 1) will allow payments to the trust to qualify as a current federal income tax deduction, 2) the income earned on the fund balance accumulates tax free, and 3) the employee is not taxed until the benefit is actually received or not taxed at all. This definition differs from that used for OPEB funding. **[*66]**

n9 These entries shall be made no less than monthly and, except for the amounts representing actual charges to construction, shall be based upon amounts that are proportional, and on an annual basis equal, to the annual text period allowances.
n10 For the purpose of this calculation the "rate allowance" shall only include the amount charged to expense accounts (*i.e.,* not charged to construction, depreciation expense and rate base allowance related to capitalized pension costs).
n11 The portion of pension costs allocated to capital accounts shall be included in the internal reserve since such costs earn a return by virtue of their inclusion in rate base or construction work in progress and through the rate allowance for depreciation accruals.
n12 However, for the purpose of calculating the company's earnings base vs. capitalization adjustment in rate proceedings, the amount in the internal reserve may be added to the company's capitalization.
n13 The cumulative interest balance less its related deferred tax.
n14 A debit balance can occur only when management, at its discretion, decides to make a contribution in excess of rate allowances or if it accrues a negative pension expense. In rate proceedings companies may seek prospective interest accruals or rate base treatment for debit balances. **[*67]**

n15 SFAS No. 109, *Accounting for Income Taxes,* Case 92-M-1005. An interim Policy Statement was issued January 15, 1993 in this case.
n16 *See* Case 90-E-0775, *Consolidated Edison Company of N.Y., Inc., et al., Order Accepting Contracts for Filing and Denying Petition* (Issued December 10, 1990), p. 8; Case 27563, *Long Island Lighting Company, Opinion and Order Determining Prudent Costs,* Opinion No. 85-23 (Issued December 16, 1985).
n17 For the purpose of calculating this deferral, both the "rate allowance" and "OPEB expense" shall only include the amount charged to expense accounts (*i.e.,* not charged to construction, depreciation expense and rate base allowance related to capitalized OPEB costs).
n18 This deferral may commence January 1, 1993 for companies which adopt SFAS No. 106 effective that date. For companies which keep their books and records on a fiscal year basis, this deferral may commence with the company's first fiscal year beginning after December 15, 1992. However, until the effects of adopting SFAS No. 106 are reflected in rates, companies may record this regulatory asset only to the extent that such deferral will not result in the company earning in excess of its last allowed rate of return. This requirement (deferral allowed only to the extent that it will not result in excess earnings) does not apply to companies whose earnings are subject to company/ratepayer sharing provisions approved by this Commission. **[*68]**

n19 Filings made in accordance with Sections III,C,2,a, b, and/or c are to include any SFAS No. 87 deferrals made in accordance with our September 22, 1987 Order concerning adoption of SFAS No. 87 (see Section III,A,5 herein).
n20 For the purpose of calculating this deferral, both the "rate allowance" and "OPEB expense" shall only include the amount charged to expense accounts (*i.e.,* not charged to construction, depreciation expense and rate base allowance related to capitalized OPEB costs).
n21 For the purpose of this Policy, "tax effect funding vehicle" for OPEB is defined as an externally held OPEB dedicated account or trust arrangement (trust) that will allow payments to the trust to qualify for a current federal income tax deduction. This definition differs from that used for pension funding.
n22 For purposes of determining the level of deferrals required by this Policy for OPEB, calculation of the OPEB rate allowance shall be consistent with the method defined in the footnotes to Section III,A,2 herein, plus any pension related or other funds or credits the company is directed to use for OPEB purposes.
n23 The limitations and safeguards detailed in Sections III,C,3,a,(1), (2), and (3) are equally applicable to pension fundss assets transferred to the OPEB trust. **[*69]**

n24 Or the company's effective date of adoption of SFAS No. 106, if that date is later than January 1, 1993.
n25 These entries shall be made no less than monthly and, except for the amounts representing actual charges to construction, shall be based upon amounts that are proportional, and on an annual basis equal, to the annual test period allowances.
n26 For the purposes of this calculation the "rate allowance" shall only include the amount charged to expense accounts (*i.e.,* not charged to construction, depreciation expense and rate base allowance related to capitalized pension costs).
n27 The portion of the liability applicable to capital accounts shall be included in the internal reserve since such costs earn a return by virtue of their inclusion in rate base or construction work in progress and through the rate allowance for depreciation accruals.
n28 However, for the purpose of calculating the company's earnings base vs. capitalization adjustment in rate proceedings, the amount in the internal reserve may be added to the company's capitalization.
n29 The cumulative interest balance less its related deferred tax.
n30 A debit balance can occur only when management, at its discretion, decides to make contributions in excess of rate allowances. In rate proceedings companies may seek prospective interest accruals or rate base treatment for debit balances. **[*70]**

n31 SFAS No. 109, *Accounting for Income Taxes,* is being developed in Case 92-M-1005. An interim Policy Statement was issued January 15, 1993 in that case.
n32 The corresponding debit is to be made to the OPEB expense account. The savings are not to be reduced by the cost of fringe benefits applicable to employees hired to replace any of the early retirees.
n33 In the instance of a broad based early retirement program, see Section III,C,3,b,(3) of this Policy for additional requirements.

APPENDIX B

PARTIES SUBMITTING COMMENTS IN REACTION TO THE NOTICE OF PROPOSED RULEMAKING IN CASE 91-M-0890 REGARDING **PENSION** AND OPEB EXPENSE

Combination Electric & Gas Utilities

1. **Central Hudson Gas and Electric** Corporation

2. Consolidated Edison Company of New York, Inc.

3. Long Island Lighting Company

4. New York State Electric and Gas Corporation

5. Niagra Mohawk Power Corporation

6. Orange and Rockland Utilities, Inc.

7. Rochester Gas and Electric Corporation

Gas Only Utilities

8. Corning Natural Gas Corporation

9. National Fuel Gas Distribution Corporation

10. The Brooklyn Union Gas Company

Telephone Utilities

11. ALLTEL New York, Inc. **[*71]**

12. AT&T Communications of New York, Inc.

13. Citizens Telephone Company

14. Contel of New York, Incorporated d/b/a GTE New York

15. Edwards, Oriskany Falls & Port Byron Telephone Companies

16. New York State Telephone Association, Inc.

17. New York Telephone Company

18. Ogden Telephone Company

19. Rochester Telephone Corporation (and subsidiaries)

Water Companies

20. Jamaica and Sea Cliff Water Companies

21. Long Island Water Corporation

22. New Rochelle Water Company

23. New York-American Water Company

24. New York Water Service Corporation

25. Spring Valley Water Company

Utility Intervenors

26. Consumer Protection Board

27. Federal Executive Agencies

28. Multiple Intervenors

CPA Firms

29. Coopers & Lybrand, Certified Public Accountants

30. Arthur Anderson & Co. SC

2000 D.C. PUC LEXIS 7

IN THE MATTER OF THE PETITION OF WASHINGTON GAS LIGHT COMPANY FOR AUTHORITY TO RETURN ACCUMULATED AND DEFERRED TRACKING ACCOUNT BALANCES

FORMAL CASE NO. 998; Order No. 11869

District of Columbia Public Service Commission

2000 D.C. PUC LEXIS 7

December 21, 2000

CORE TERMS: customer, deferred, refund, interim, one-time, pension expense, natural gas, accumulated, tracking, approve, winter, therm, interim order, public interest, final order, pension, modification, residential, weather, belong, usage

OPINION:

INTERIM ORDER

1. By this Order, the Public Service Commission of the District of Columbia ("Commission") grants, on an interim basis, the petition of Washington Gas Light Company ("WGL") to return to WGL customers $ 11.1 million of excess payments as a one-time credit on their February 2001 bills. The Commission grants this petition on an interim basis subject to later modification because of the emergency nature of this petition. WGL is requested to answer data requests by January 5, 2001. Additionally, interested parties are requested to comment on this petition by January 10, 2001.

I. BACKGROUND

2. On December 20, 2000, WGL filed a petition seeking Commission authorization for returning accumulated and deferred tracking account balances. n1 In support of its petition, WGL notes that three accounts, the Pension Expense, Regulatory Expense, and Other Post-Retirement Benefits other than **Pensions** ("OPEB") Expense tracking accounts, have accumulated excess amounts, to a total of $ 11.1 million. WGL proposes the return of these funds to WGL customers in the form of a one-time credit on firm customers' February 2001 bills, in order to provide some relief to the rapid and continued increase in natural gas bills this winter. n2

n1 Formal Case No. 998, In The Matter Of The Petition Of **Washington Gas Light** Company For Authority To Return Accumulated And Deferred Tracking Account Balances, Petition of Washington Gas Light Company, filed December 20, 2000.

n2 WGL Petition, at 2.

3. WGL proposes to refund the excess amounts through a credit on customers' February

2001 gas bills. The credit would be applied on a customer class basis, allowing the credit to be calculated based on the type of customer, residential or non-residential, apportioned by subclass. n3 In general, WGL estimates that a residential heating customer would receive, on average, an approximately $ 50 credit on the February 2001 gas bill. n4

n3 WGL Petition, at 6.

n4 WGL Petition, at 7.

II. DISCUSSION

4. In its petition, WGL proposes to refund excess amounts collected in its deferred pension expense, deferred regulatory expense, and deferred OPEB accounts to its customers. WGL explains that since the expenses in all three of these accounts are considered operating expenses, these expenses are recoverable from WGL rates. n5 WGL asserts that the excess amounts in the deferred pension expense (in the amount of $ 8.6 million) and deferred OPEB accounts (in the amount of $ 780,000) have accumulated due to the unanticipated expansion of the stock market. n6 WGL also claims that it has been able to accumulate $ 1.4 million of deferred regulatory expenses because there has been no rate case. n7 WGL asserts that for all three accounts, the excess collection does not affect the return authorized by the Commission and earned by WGL. n8

n5 WGL Petition, at 3, 4, 5.

n6 WGL Petition, at 4, 5.

n7 WGL Petition, at 5.

n8 WGL Petition, at 4, 5, 6.

5. WGL argues that its refund proposal is in the public interest. WGL notes that since the excess amounts in these funds actually belong to WGL customers, refund of these funds is appropriate. WGL asserts that its proposal returns the excess expeditiously and in a manner likely to assist customers dealing with the unexpected steep increase in natural gas prices this winter. For these reasons, WGL requests the Commission to approve its refund proposal. n9

n9 WGL Petition, at 7.

6. The Commission tentatively concludes that WGL's petition is in the public interest. The Commission believes that the excess amounts in the deferred pension, deferred regulatory, and OPEB accounts belong to WGL customers, so a refund of those excess amounts is appropriate. Additionally, the Commission finds that WGL's proposal to refund the excess amounts through a one-time credit on the February bill is probably appropriate, as natural gas prices have escalated and will likely continue to increase throughout the winter. A one-time credit would be easier to administer than credits spread throughout several months.

Obtaining a credit in February is probably more effective than obtaining a credit later in the year. Approving the petition at this time would permit WGL to ensure that the credit is applied to all February 2001 bills.

7. While the Commission believes that it is necessary to approve WGL's petition at this time in order to ensure that the credit is included in all February 2001 bills, we must approve WGL's petition on an interim basis only. Interested parties have not yet had the opportunity to comment on WGL's proposal, which is required before the Commission may issue a final order. Additionally, the Commission seeks responses to the following two data requests before the Commission makes a final determination of the issues presented in the petition.

8. Therefore, the Commission provisionally grants WGL's petition on an interim basis, so that WGL has the necessary time to prepare to add the credit to its February 2001 bills. In order for the Commission to issue a final order in time for any credit to be actually added to these bills, WGL is directed to submit any comments and the responses to the two data requests listed below by **January 5, 2001**. Interested parties have until **January 10, 2001** to comment on WGL's petition. The Commission retains the right to modify this order to any extent necessary after reviewing the comments and data request responses.

1. Since the proposed refunding of the $ 11.1 million is based on normal weather therm sales, what will happen if the actual therm usage deviates from the normal weather therm usage?

2. Does WGL desire to discontinue the present tracking procedures for these deferred and amortization accounts?

THEREFORE, IT IS ORDERED THAT:

9. The Petition of Washington Gas Light Company submitted December 20, 2000 is APPROVED on an interim basis, subject to comment and to modification as deemed necessary by the Commission.

10. Washington Gas Light Company shall file responses to the data requests included in this interim order by **January 5, 2001.**

11. Any interested party shall submit comments on the petition by **January 10, 2001.**

A TRUE COPY:

BY DIRECTION OF THE COMMISSION:

CHIEF CLERK

JESSE P. CLAY, JR.

COMMISSION SECRETARY

Terms: **washington gas light w/50 pension** (Edit Search)
View: Full
Date/Time: Wednesday, April 7, 2004 - 11:30 AM EDT

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ENTERGY CORP DE

Filing Type: 10-K
Description: N/A
Filing Date: 12/31/03

Ticker: ETR
Cusip: 29364G
State: LA
Country: US
Primary SIC: 4931
Primary Exchange: NYS
Billing Cross Reference:
Date Printed: 04/13/04

Mark-to-market Accounting

The EITF reached a consensus to rescind Issue No. 98-10 effective January 1, 2003. Rescinding Issue No. 98-10 resulted in some energy-related contracts being accounted for on an accrual basis that were previously accounted for on a mark-to-market basis. Contracts that meet the provisions of SFAS 133 to qualify as derivatives are marked-to-market in accordance with the guidance in SFAS 133. Contracts such as capacity, transportation, storage, tolling, and full requirements contracts that are based on physical assets and do not meet the provisions of SFAS 133 to qualify as derivatives are accounted for using accrual accounting. Energy commodity inventories held by trading companies such as physical natural gas are accounted for at the lower of cost or market. The adoption of the consensus had minimal cumulative and ongoing earnings effects for Entergy's Energy Commodity Services business.

As required by generally accepted accounting principles, Entergy and Entergy-Koch mark-to-market commodity instruments held by them for trading and risk management purposes that are considered derivatives under SFAS 133. Because of the significant estimates and uncertainties inherent in mark-to-market accounting, this method is considered a critical accounting estimate for the Energy Commodity Services segment. Examples of commodity instruments that are marked to market include:

* commodity futures, options, swaps, and forwards that are expected to be net settled; and

* power sales agreements that do not involve delivery of power from Entergy's power plants.

Conversely, commodity contracts that are not considered derivatives, generally because they involve physical delivery of a commodity to the purchaser, are not marked to market. Examples of commodity contracts that are not marked to market include:

* the PPAs for Entergy's Non-Utility Nuclear plants;

* capacity purchases and sales by the U.S. Utility companies; and

* forward contracts that will result in physical delivery.

Fair value estimates of the commodity instruments that are marked to market are made at discrete points in time based on relevant market information. Market quotes are used in determining fair value whenever they are available. When market quotes are not available (e.g., long-dated commodity contract), other information is used, including transactional data and internally developed models. Fair value estimates based on these other methodologies are necessarily subjective in nature and involve uncertainties and matters of significant judgment. These uncertainties include projections of macroeconomic trends and future commodity prices, including supply and demand levels and future price volatility. The impact of these uncertainties, however, is lessened by the relatively short-term nature of the mark-to-market positions held by Entergy and EKT.

Pension and Other Postretirement Benefits

Entergy sponsors defined benefit pension plans which cover substantially all employees. Additionally, Entergy provides postretirement health care and life insurance benefits for substantially all employees who reach retirement age while still working for Entergy. Entergy's reported costs of providing these benefits, as described in Note 11 to the consolidated financial statements, are impacted by numerous factors including the provisions of the plans, changing employee demographics and various actuarial calculations, assumptions, and accounting mechanisms. Because of the complexity of these calculations, the long-term nature of these obligations, and the importance of the assumptions utilized, Entergy's estimate of these costs is a critical accounting estimate for the U.S. Utility and Non-Utility Nuclear segments.

Assumptions

Key actuarial assumptions utilized in determining these costs include:

* Discount rates used in determining the future benefit obligations;
* Projected health care cost trend rates;
* Expected long-term rate of return on plan assets; and
* Rate of increase in future compensation levels.

Entergy reviews these assumptions on an annual basis and adjusts them as necessary. The falling interest rate environment and poor performance of the financial equity markets over the past several years have impacted Entergy's funding and reported costs for these benefits. In addition, these trends have caused Entergy to make a number of adjustments to its assumptions.

In selecting an assumed discount rate, Entergy reviews market yields on high-quality corporate debt. Based on recent market trends, Entergy reduced its discount rate from 7.5% in 2001 and 6.75% in 2002 to 6.25% in 2003. Entergy reviews actual recent cost trends and projected future trends in establishing health care cost trend rates. Based on this review, Entergy increased its health care cost trend rate assumption used in calculating the 2003 accumulated postretirement benefit obligation. The assumed health care cost trend rate is a 10% increase in health care costs in 2004 gradually decreasing each successive year until it reaches a 4.5% annual increase in health care costs in 2010 and beyond.

In determining its expected long-term rate of return on plan assets, Entergy reviews past long-term performance, asset allocations, and long-term inflation assumptions. Entergy targets an asset allocation for its pension plan assets of roughly 66% equity securities, 30% fixed income securities, and 4% other investments. The target allocation for Entergy's other postretirement benefit assets is 45% equity securities and 55% fixed income securities. Based on recent market trends, Entergy decreased its expected long-term rate of return on plan assets from 9% in 2001 to 8.75% for 2002 and 2003. The trend of reduced inflation caused Entergy to reduce its assumed rate of increase in future compensation levels from 4.6% in 2001 to 3.25% in 2002 and 2003.

Cost Sensitivity

The following chart reflects the sensitivity of pension cost to changes in certain actuarial assumptions (in thousands):

Actuarial Assumption	Change in Assumption	Impact on 2003 Pension Cost	Impact on Projected Benefit Obligation
		Increase/(Decrease)	
Discount rate	(0.25%)	$4,882	$83,651
Rate of return on plan assets	(0.25%)	$4,346	-
Rate of increase in compensation	0.25%	$4,039	$28,101

The following chart reflects the sensitivity of postretirement benefit cost to changes in certain actuarial assumptions (in thousands):

Actuarial Assumption	Change in Assumption	Impact on 2003 Postretirement Benefit	Impact on Accumulated Postretirement Benefit

		Cost Increase/(Decrease)	Obligation
Health care cost trend	0.25%	$5,206	$25,979
Discount rate	(0.25%)	$3,278	$29,500

Each fluctuation above assumes that the other components of the calculation are held constant.

Accounting Mechanisms

In accordance with SFAS No. 87, "Employers' Accounting for Pensions," Entergy utilizes a number of accounting mechanisms that reduce the volatility of reported pension costs. Differences between actuarial assumptions and actual plan results are deferred and are amortized into cost only when the accumulated differences exceed 10% of the greater of the projected benefit obligation or the market-related value of plan assets. If necessary, the excess is amortized over the average remaining service period of active employees.

Additionally, Entergy smoothes the impact of asset performance on pension expense over a twenty-quarter phase-in period through a "market-related" value of assets calculation. Since the market-related value of assets recognizes investment gains or losses over a twenty-quarter period, the future value of assets will be impacted as previously deferred gains or losses are recognized. As a result, the losses that the pension plan assets experienced in 2002 may have an adverse impact on pension cost in future years depending on whether the actuarial losses at each measurement date exceed the 10% corridor in accordance with SFAS 87.

Costs and Funding

In 2003, Entergy's total pension cost was $108 million, including a $47 million charge related to the voluntary severance program. Entergy anticipates 2004 pension cost to increase to $87 million due to a decrease in the discount rate from 6.75% to 6.25% and the phased-in effect of poor asset performance. Pension funding was $35 million for 2003 and in 2004 is projected to be $110 million due to the poor performance of the financial equity markets.

Due to negative pension plan asset returns from 2000 to 2002, Entergy's accumulated benefit obligation at December 31, 2003 and 2002 exceeded plan assets. As a result, Entergy was required to recognize an additional minimum liability as prescribed by SFAS 87. At December 31, 2003 Entergy reduced its additional minimum liability to $180.2 million ($149.4 million net of related pension assets) from $208.1 million ($175 million net of related pension assets) at December 31, 2002. This reduced the charge to other comprehensive income to $9.3 million at December 31, 2003 from $11 million at December 31, 2002, after reductions for the unrecognized prior service cost, amounts recoverable in rates, and taxes. Net income for 2003 and 2002 were not affected.

Total postretirement health care and life insurance benefit costs for Entergy in 2003 were $165 million, including a $64 million charge related to the voluntary severance program. In December 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 became law. The Act introduces a prescription drug benefit under Medicare (Part D) as well as a federal subsidy to employers who provide a retiree prescription drug benefit that is at least actuarially equivalent to Medicare Part D. Currently, specific authoritative guidance on the accounting for the federal subsidy is pending. Entergy expects 2004 postretirement health care and life insurance benefit costs to approximate $102 million.

Other Contingencies

Entergy, as a company with multi-state domestic utility operations, and which also had investments in international projects, is subject to a number of federal, state, and international laws and regulations and other factors and conditions in the areas in which it operates, which potentially subject it to environmental, litigation, and other risks. Entergy periodically evaluates its exposure for such risks and records a reserve for those matters which are considered probable and estimable in accordance with generally accepted accounting principles.

Environmental

Entergy must comply with environmental laws and regulations applicable to the handling and disposal of hazardous waste. Under these various laws and regulations, Entergy could incur substantial costs to restore properties consistent with the various standards. Entergy conducts studies to determine the extent of any required remediation and has recorded reserves based upon its evaluation of the likelihood of loss and expected dollar amount for each issue. Additional sites could be identified which require environmental remediation for which Entergy could be liable. The amounts of environmental reserves recorded can be significantly affected by the following external events or conditions:

* Changes to existing state or federal regulation by governmental authorities having jurisdiction over air quality, water quality, control of toxic substances and hazardous and solid wastes, and other environmental matters.

* The identification of additional sites or the filing of other complaints in which Entergy may be asserted to be a potentially responsible party.

* The resolution or progression of existing matters through the court system or resolution by the EPA.

Litigation

Entergy has been named as defendant in a number of lawsuits involving employment, ratepayer, and injuries and damages issues, among other matters. Entergy periodically reviews the cases in which it has been named as defendant and assesses the likelihood of loss in each case as probable, reasonably estimable, or remote and records reserves for cases which have a probable likelihood of loss and can be estimated. Notes 2 and 9 to the consolidated financial statements include more detail on ratepayer and other lawsuits and management's assessment of the adequacy of reserves recorded for these matters. Given the environment in which Entergy operates, and the unpredictable nature of many of the cases in which Entergy is named as a defendant, however, the ultimate outcome of the litigation Entergy is exposed to has the potential to materially affect the results of operations of Entergy, or its operating company subsidiaries.

Sales Warranty and Tax Reserves

Entergy's operations, including acquisitions and divestitures, require Entergy to evaluate risks such as the potential tax effects of a transaction, or warranties made in connection with such a transaction. Entergy believes that it has adequately assessed and provided for these types of risks, where applicable. Any reserves recorded for these types of issues, however, could be significantly affected by events such as claims made by third parties under warranties, additional transactions contemplated by Entergy, or completion of reviews of the tax treatment of certain transactions or issues by taxing authorities. Entergy does not expect a material adverse effect from these matters.

ENTERGY CORPORATION AND SUBSIDIARIES

SELECTED FINANCIAL DATA - FIVE-YEAR COMPARISON

In December 1988, System Energy sold 11.5% of its undivided ownership interest in Grand Gulf 1 for the aggregate sum of $500 million. Subsequently, System Energy leased back its interest in the unit for a term of 26-1/2 years. System Energy has the option of terminating the lease and repurchasing the 11.5% interest in the unit at certain intervals during the lease. Furthermore, at the end of the lease term, System Energy has the option of renewing the lease or repurchasing the 11.5% interest in Grand Gulf 1.

System Energy is required to report the sale-leaseback as a financing transaction in its financial statements. For financial reporting purposes, System Energy expenses the interest portion of the lease obligation and the plant depreciation. However, operating revenues include the recovery of the lease payments because the transactions are accounted for as a sale and leaseback for ratemaking purposes. Consistent with a recommendation contained in a FERC audit report, System Energy recorded as a net regulatory asset the difference between the recovery of the lease payments and the amounts expensed for interest and depreciation and is recording this difference as a regulatory asset or liability on an ongoing basis, resulting in a zero net balance at the end of the lease term. The amount of this net regulatory asset was $83.2 million and $79.5 million as of December 31, 2003 and 2002, respectively.

As of December 31, 2003, System Energy had future minimum lease payments (reflecting an implicit rate of 7.02%), which are recorded as long-term debt as follows:

NOTE 11. RETIREMENT, OTHER POSTRETIREMENT BENEFITS, AND DEFINED CONTRIBUTION PLANS

Pension Plans

Entergy has seven pension plans covering substantially all of its employees: "Entergy Corporation Retirement Plan for Non-Bargaining Employees," "Entergy Corporation Retirement Plan for Bargaining Employees," "Entergy Corporation Retirement Plan II for Non-Bargaining Employees, " "Entergy Corporation Retirement Plan II for Bargaining Employees, " "Entergy Corporation Retirement Plan III, " "Entergy Corporation Retirement Plan IV for Non-Bargaining Employees, " and "Entergy Corporation Retirement Plan IV for Bargaining Employees. " Except for the Entergy Corporation Retirement Plan III, the pension plans are noncontributory and provide pension benefits that are based on employees' credited service and compensation during the final years before retirement. The Entergy Corporation Retirement Plan III includes a mandatory employee contribution of 3% of earnings during the first 10 years of plan participation, and allows voluntary contributions from 1% to 10% of earnings for a limited group of employees. Entergy Corporation and its subsidiaries fund pension costs in accordance with contribution guidelines established by the Employee Retirement Income Security Act of 1974, as amended, and the Internal Revenue Code of 1986, as amended. The assets of the plans include common and preferred stocks, fixed-income securities, interest in a money market fund, and insurance contracts. As of December 31, 2003 and December 31, 2002, Entergy recognized an additional minimum pension liability for the excess of the accumulated benefit obligation over the fair market value of plan assets. In accordance with FASB 87, an offsetting intangible asset, up to the amount of any unrecognized prior service cost, was also recorded, with the remaining offset to the liability recorded as a regulatory asset reflective of the recovery mechanism for pension costs in Entergy's jurisdictions. Entergy's domestic utility companies' and System Energy's pension costs are recovered from customers as a component of cost of service in each of its jurisdictions. Entergy uses a December 31 measurement date for its pension plans.

Components of Net Pension Cost

Total 2003, 2002, and 2001, pension costs of Entergy Corporation and its subsidiaries, including amounts capitalized, included the following components:

Pension Obligations, Plan Assets, Funded Status, Amounts Not Yet Recognized and

Recognized in the Balance Sheet as of December 31, 2003 and 2002:

Other Postretirement Benefits

Entergy also provides health care and life insurance benefits for retired employees. Substantially all domestic employees may become eligible for these benefits if they reach retirement age while still working for Entergy. Entergy uses a December 31 measurement date for its postretirement benefit plans.

Effective January 1, 1993, Entergy adopted SFAS 106, which required a change from a cash method to an accrual method of accounting for postretirement benefits other than pensions. At January 1, 1993, the actuarially determined accumulated postretirement benefit obligation (APBO) earned by retirees and active employees was estimated to be approximately $241.4 million for Entergy (other than Entergy Gulf States) and $128 million for Entergy Gulf States. Such obligations are being amortized over a 20-year period that began in 1993. For the most part, the domestic utilities and System Energy recover SFAS 106 costs from customers and are required to fund postretirement benefits collected in rates to an external trust.

Components of Net Postretirement Benefit Cost

Total 2003, 2002, and 2001 other postretirement benefit costs of Entergy Corporation and its subsidiaries, including amounts capitalized and deferred, included the following components (in thousands):

	2003	2002	2001
	(In Thousands)		
Service cost - benefits earned during the period	$37,799	$29,199	$24,225
Interest cost on APBO	52,746	44,819	38,811
Expected return on assets	(15,810)	(14,066)	(12,578)
Amortization of transition obligation	15,193	17,874	17,874
Amortization of prior service cost	(925)	992	992
Recognized net (gain)/loss	12,369	1,874	(1,506)
Curtailment loss	57,958	-	-
Special termination benefits	5,444	-	-
Net other postretirement benefit cost	$164,774	$80,692	$67,818

Other Postretirement Benefit Obligations, Plan Assets, Funded Status, and Amounts Not Yet Recognized and Recognized in the Balance Sheet as of December 31, 2003 and 2002:

	December 31, 2003	2002
	(In Thousands)	
Change in APBO		
Balance at beginning of year	$799,506	$590,731
Service cost	37,799	29,199
Interest cost	52,746	44,819
Actuarial loss	115,966	159,143
Benefits paid	(48,379)	(35,861)
Plan amendments (a)	(84,722)	-
Plan participant contributions	7,074	-
Curtailment	56,369	-
Special termination benefits	5,444	-
Acquisition of subsidiary	-	11,475
Balance at end of year	$941,803	$799,506
Change in Plan Assets		

Fair value of assets at begininning of year	$182,692	$158,190
Actual return on plan assets	22,794	(11,559)
Employer contributions	63,265	59,542
Plan participant contributions	7,074	-
Benefits paid	(48,379)	.(35,861)
Acquisition of subsidiary	-	12,380
Fair value of assets at end of year	$227,446	$182,692
Funded status	($714,357)	($616,814)
Amounts not yet recognized in the balance sheet:		
Unrecognized transition obligation	44,815	114,724
Unrecognized prior service cost	(20,746)	3,522
Unrecognized net loss	336,005	245,795
Accrued other postretirement benefit cost recognized in the balance sheet	($354,283)	($252,773)

(a) Reflects plan design changes, including a change in the participation assumption for non-bargaining employees effective August 1, 2003.

Pension and Other Postretirement Plans' Assets

Entergy's pension and postretirement plans weighted-average asset allocations by asset category at December 31, 2003 and 2002 are as follows:

	Pension		Postretirement	
	2003	2002	2003	2002
Domestic Equity Securities	56%	50%	37%	34%
International Equity Securities	14%	10%	0%	1%
Fixed Income Securities	28%	37%	60%	64%
Other	2%	3%	3%	1%

Entergy's trust asset investment strategy is to invest the assets in a manner whereby long-term earnings on the assets (plus cash contributions) provide adequate funding for retiree benefit payments. Adequate funding is described as a 90% confidence that assets equal or exceed liabilities due five years in the future, and a corresponding 75% confidence level ten years out. The mix of assets is based on an optimization study that identifies asset allocation targets in order to achieve the maximum return for an acceptable level of risk while minimizing the expected contributions and pension and postretirement expense.

To perform such an optimization study, Entergy first makes assumptions about certain market characteristics, such as expected asset class investment returns, volatility (risk) and correlation coefficients among the various asset classes. Entergy does so by examining (or hiring a consultant to provide such analysis) historical market characteristics of the various asset classes over all of the different economic conditions that have existed. Entergy then examines and projects the economic conditions expected to prevail over the study period. Finally, the historical characteristics to reflect the expected future conditions are adjusted to produce the market characteristics that will be assumed in the study.

The optimization analysis utilized in Entergy's latest study produced the following approved asset class target allocations.

	Pension	Postretirement
Domestic Equity Securities	54%	37%
International Equity Securities	12%	8%
Fixed Income Securities	30%	55%
Other (Cash and GACs)	4%	0%

These allocation percentages combined with each asset class' expected investment return produced an aggregate return expectation of 9.59% for pension assets, 5.45% for taxable postretirement assets, and 7.19% for non-taxable postretirement assets. These returns are consistent with Entergy's disclosed expected return on assets of 8.75% (non-taxable assets) and 5.5% (taxable assets).

Since precise allocation targets are inefficient to manage security investments, the following ranges were established to produce an acceptable economically efficient plan to manage to targets:

	Pension	Postretirement
Domestic Equity Securities	49 % to 59%	32 % to 42%
International Equity Securities	7% to 17%	3% to 12%
Fixed Income Securities	25% to 35%	50% to 60%
Other	0% to 10%	0% to 5%

Accumulated Pension Benefit Obligation

The accumulated benefit obligation for Entergy's pension plans was $2.1 billion and $1.7 billion at December 31, 2003 and 2002, respectively.

Estimated Future Benefit Payments

Based upon the assumptions used to measure the company's pension and postretirement benefit obligation at December 31, 2003, and including pension and postretirement benefits attributable to estimated future employee service, Entergy expects that pension benefits to be paid over the next ten years is as follows:

	Estimated Future Benefits Payments	
	Pension	Postretirement
	(In Thousands)	
Year(s)		
2004	$96,764	$53,666
2005	$98,378	$57,271
2006	$100,411	$58,389
2007	$103,225	$61,171
2008	$107,120	$63,393
2009 - 2013	$631,594	$358,648

Contributions

Entergy expects to contribute $110 million (which includes about $1 million in employee contributions) to its pension plans and $68.6 million to other postretirement plans in 2004.

Additional Information

The change in the minimum pension liability included in other comprehensive income and regulatory assets was as follows for 2003 and 2002:

	2003	2002
	(In Thousands)	
Increase/(decrease) in the minimum pension liability included in:		
Other comprehensive income	($1,639)	$17,016
Regulatory assets	($23,768)	$157,789

Actuarial Assumptions

The assumed health care cost trend rate used in measuring the APBO of Entergy was 10% for 2004, gradually decreasing each successive year until it reaches 4.5% in 2010 and beyond. The assumed health care cost trend rate used in measuring the Net Other Postretirement Benefit Cost of Entergy was 10% for 2004, gradually decreasing each successive year until it reaches 4.5% in 2009 and beyond. A one percentage point increase in the assumed health care cost trend rate for 2003 would have increased the APBO and the sum of the service cost and interest cost of Entergy as of December 31, 2003 as follows:

The significant actuarial assumptions used in determining the pension PBO and the SFAS 106 APBO for 2003, 2002, and 2001 were as follows:

	2003	2002	2001
Weighted-average discount rate:			
Pension	6.25%	6.75%	7.50%
Other postretirement	6.71%	6.75%	7.50%
Weighted-average rate of increase in future compensation levels	3.25%	3.25%	4.60%
Expected long-term rate of return on plan assets:			
Taxable assets	5.5%	5.50%	5.50%
Non-taxable assets	8.75%	8.75%	9.00%

The significant actuarial assumptions used in determining the net periodic pension and other postretirement benefit costs for 2003, 2002, and 2001 were as follows:

	2003	2002	2001
Weighted-average discount rate	6.75%	7.5%	7.5%
Weighted-average rate of increase in future compensation levels	3.25%	4.6%	4.6%
Expected long-term rate of return on plan assets:			
Taxable assets	5.5%	5.5%	5.5%
Non-taxable assets	8.75%	9.0%	9.0%

Entergy's remaining pension transition assets are being amortized over the greater of the remaining service period of active participants or 15 years, and its SFAS 106 transition obligations are being amortized over 20 years.

Voluntary Severance Program

During 2003, Entergy offered a voluntary severance program to certain groups of employees. As a result of this program, Entergy recorded additional pension and postretirement costs (including amounts capitalized) of $110.3 million for special termination benefits and plan curtailment charges. These amounts are included in the net pension cost and net postretirement benefit cost for the year ended December 31, 2003.

Medicare Prescription Drug, Improvement and Modernization Act of 2003

In December 2003, the President signed the Medicare Prescription Drug, Improvement and Modernization Act of 2003 into law. The Act introduces a prescription drug benefit under Medicare (Part D) as well as federal subsidy to employers who provide a retiree prescription drug benefit that is at least actuarially equivalent to Medicare Part D.

Currently, specific authoritative guidance on the accounting for the federal subsidy is pending. As allowed by Financial Accounting Standards Board Staff Position No. FAS 106-1, Entergy has elected to record an estimate of the effects of the Act in accounting for its postretirement benefit plans under SFAS 106 and in providing disclosures required by SFAS No. 132 (revised 2003), Employers' Disclosures about Pensions and Other Postretirement Benefits.

Based on actuarial analysis of prescription drug benefits, estimated future Medicare subsidies are expected to reduce the December 31, 2003 Accumulated Postretirement Benefit Obligation by $56 million. For the year ended December 31, 2003 the impact of the Act on Net Postretirement Cost was immaterial, as it reflected only one month's impact of the Act. When specific guidance on accounting for federal subsidy is issued, these estimates could change.

Defined Contribution Plans

Entergy sponsors the Savings Plan of Entergy Corporation and Subsidiaries (Savings Plan). The Savings Plan is a defined contribution plan covering eligible employees of Entergy and its subsidiaries. Through January 31, 2004, the Savings Plan provided that the employing Entergy subsidiary:

* make matching contributions to the Savings Plan in an amount equal to 75% of the participants' basic contributions, up to 6% of their eligible earnings, in shares of Entergy Corporation common stock if the employees direct their company-matching contribution to the purchase of Entergy Corporation's common stock; or
* make matching contributions in the amount of 50% of the participants' basic contributions, up to 6% of their eligible earnings, if the employees direct their company-matching contribution to other investment funds.

Effective February 1, 2004, the employing Entergy subsidiary will make matching contributions to the Savings Plan in an amount equal to 70% of the participants' basic contributions, up to 6% of their eligible earnings. The 70% match will be allocated to investments as directed by the employee.

Entergy also sponsors the Savings Plan of Entergy Corporation and Subsidiaries II (began in 2001), the Savings Plan of Entergy Corporation and Subsidiaries III (began in 2002), and the Savings Plan of Entergy Corporation and Subsidiaries V (began in 2002). The plans are defined contribution plans that cover eligible employees, as defined by each plan, of Entergy and its subsidiaries. The employing Entergy subsidiary makes matching contributions equal to 50% of the participants' participating contributions for each of these plans.

Entergy's subsidiaries' contributions to the plans collectively were $31.5 million in 2003, $29.6 million in 2002, and $25.4 million in 2001 to these defined contribution plans. The majority of the contributions were to the Savings Plan.

WGL HOLDINGS INC

Filing Type: 10-K
Description: N/A
Filing Date: 09/30/03

Ticker: WGL
Cusip: 92924F
State: DC
Country: US
Primary SIC: 4924
Primary Exchange: NYS
Billing Cross Reference:
Date Printed: 04/13/04

Net income	$ 112,342	48,756	$ 2.30
Fiscal Year Ended September 30, 2002			
Basic EPS:			
Net income	$ 39,121	48,563	$ 0.81
Stock-based compensation plans	--	88	
Diluted EPS:			
Net income	$ 39,121	48,651	$ 0.80
Fiscal Year Ended September 30, 2001			
Basic EPS:			
Net income	$ 82,445	47,120	$ 1.75
Stock-based compensation plans	--	70	
Diluted EPS:			
Net income	$ 82,445	47,190	$ 1.75

11. INCOME TAXES

The Company and its subsidiaries file a consolidated federal income tax return. The Company's federal income tax returns for all years through September 30, 1999 have been reviewed and closed, or closed without review by the Internal Revenue Service. The Company and its subsidiaries also participate in a tax sharing agreement that establishes the method for allocating losses utilized on a consolidated federal income tax return. State income tax returns are filed on a separate company basis in states where the Company has operations and/or a requirement to file.

The Statements of Income Taxes provide the following: (i) the components of income tax expense; (ii) a reconciliation between the statutory federal income tax rate and the effective income tax rate and (iii) the components of accumulated deferred income tax assets and liabilities at September 30, 2003 and 2002.

During fiscal year ended September 30, 2003, the Company recognized tax benefits of $2.4 million from the release of a valuation allowance associated primarily with previously unrecognized capital losses. A valuation allowance of $4.0 million remained for unused tax benefits of capital losses as of September 30, 2003.

12. PENSION AND OTHER POST-RETIREMENT BENEFIT PLANS

Washington Gas maintains a qualified, trusteed, non-contributory defined benefit pension plan covering all active and vested former employees of Washington Gas. To the extent allowable by law, Washington Gas funds pension costs accrued for the qualified plan. Assets under the defined benefit pension plan are valued using a method designed to spread realized and unrealized asset gains and losses from all assets over a period of five years.

Notes to Consolidated Financial Statements (continued)

Executive officers of Washington Gas also participate in a non-funded supplemental executive retirement plan (SERP). A rabbi trust has been established for the potential future funding of the SERP liability.

As of September 30, 2003, the Company had recorded a minimum pension obligation that included $5.3 million in regards to the SERP with corresponding adjustments to "Regulatory assets" and "Other comprehensive income" of $4.2 million and $1.1 million, respectively. Based on the regulatory treatment in certain jurisdictions, the Company believes that it will be able to ultimately recover a significant portion of the additional minimum liability through future rates. Should the Company not recover this minimum liability through future rates, a balance sheet adjustment would be made to reclassify the obligation from "Regulatory assets" to "Other comprehensive income," a component of "Common shareholders' equity."

Certain subsidiaries of the Company offer defined-contribution savings plans to eligible employees, covering all employee groups. These plans allow participants to defer on a pre-tax or after-tax basis, a portion of their salaries for investment in various alternatives. The Company makes matching contributions to the amounts contributed by employees in accordance with the specific plan provisions. The Company's contribution to the plans were $3.0 million, $2.9 million and $2.6 million during fiscal years 2003, 2002 and 2001, respectively.

The Company provides certain healthcare and life insurance benefits for retired employees. Substantially all employees of the regulated utility may become eligible for such benefits if they attain retirement status while working for Washington Gas. The Company accounts for these benefits under the provisions of SFAS No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions. The Company elected to amortize the accumulated post-retirement benefit obligation of $190.6 million existing at the October 1, 1993 adoption date of this standard, known as the transition obligation, over a twenty-year period. Effective January 1, 2004, changes are being made to post-retirement medical benefits that reduced the Company's post-retirement benefit obligations by $37.9 million as of September 30, 2003.

The following tables show certain information about the Company's post-retirement benefits:

Post-Retirement Benefits

(In millions)	Pension Benefits		Health & Life Benefits	
Years Ended September 30,	2003	2002	2003	2002
Change in benefit obligation				
Benefit obligation at beginning of year	$ 567.1	$ 501.3	$ 322.9	$ 257.1
Service cost	9.2	8.1	8.0	6.1
Interest cost	35.9	35.5	20.5	18.2
Change in plan benefits	--	--	(37.9)	--
Actuarial loss	35.6	53.0	62.7	56.1
Benefits paid	(31.9)	(30.8)	(15.0)	(14.6)
Benefit obligation at end of year	615.9	567.1	361.2	322.9
Change in plan assets				

Fair value of plan assets at beginning of year	611.2	681.7	147.3	132.2
Actual return/(loss) on plan assets	83.1	(38.6)	2.8	4.5
Company contributions	1.2	1.3	28.4	25.2
Expenses	(2.1)	(2.4)	--	--
Benefits paid	(31.9)	(30.8)	(15.0)	(14.6)
Fair value of plan assets at end of year	661.5	611.2	163.5	147.3
Funded status				
Funded status of plan	45.6	44.1	(197.7)	(175.6)
Unrecognized actuarial net (gains)/losses	(11.3)	(19.4)	124.3	54.1
Unrecognized prior service cost	17.8	20.2	--	--
Unrecognized transition (assets) obligation	0.2	0.3	57.4	104.9
Prepaid (accrued) benefit cost	$ 52.3	$ 45.2	$ (16.0)	$ (16.6)

	Pension Benefits		Health & Life Benefits	
(In millions)	2003	2002	2003	2002
Total amounts recognized on balance sheet				
Prepaid benefit cost	$ 66.8	$ 58.5	--	--
Accrued benefit liability	(19.8)	(18.5)	(16.0)	(16.6)
Regulatory asset	4.2	5.2	--	--
Accumulated other comprehensive income	1.1	--	--	--
Total recognized	$ 52.3	$ 45.2	$ (16.0)	$ (16.6)

	Pension Benefits		Health & Life Benefits	
Assumptions as of September 30,	2003	2002	2003	2002

Discount rate				
Components of pension cost	6.50%	7.25%	6.50%	7.25%
Benefits obligations	6.00%	6.50%	6.00%	6.50%
Expected return on plan assets	8.50%	8.50%	8.25%	8.25%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%

The Company has assumed healthcare cost trend rates for fiscal year 2003 for Medicare eligible and non-Medicare eligible retirees of 9.92 percent and 8.50 percent, respectively, and expects these rates to decrease gradually to 5.75 percent and 5.50 percent, respectively, in 2007 and remain at those levels thereafter.

Components of Net Periodic Benefit Costs (Income)

	Pension Benefits			Health and Life Benefits		
(In millions)	2003	2002	2001	2003	2002	2001
Components of net periodic benefit cost (income)						
Service cost	$ 9.2	$ 8.1	$ 7.8	$ 8.0	$ 6.1	$ 4.4
Interest cost	35.9	35.5	34.7	20.6	18.3	16.1
Expected return on plan assets	(54.0)	(55.8)	(51.7)	(11.4)	(10.2)	(8.8)
Recognized prior service cost	2.3	2.3	2.3	--	--	--
Recognized actuarial loss (gain)	0.5	(6.5)	(10.2)	1.1	--	(2.5)
Amortization of transition obligation (asset)-net	0.2	(0.9)	(2.4)	9.5	9.5	9.5
Net periodic benefit cost (income)	(5.9)	(17.3)	(19.5)	27.8	23.7	18.7
Amount capitalized as construction cost	1.5	4.4	3.6	(5.8)	(4.2)	(3.8)
Amount deferred as regulatory asset/liability-net	0.8	3.4	3.4	0.6	1.4	2.1
Amount charged (credited) to expense	$ (3.6)	$ (9.5)	$ (12.5)	$ 22.6	$ 20.9	$ 17.0

The projected benefit obligation and accumulated benefit obligation for the Company's non-funded SERP, which had accumulated benefits in excess of plan assets, were $21.8 million and $19.7 million, respectively, as of September 30, 2003, and $20.5 million and $18.4 million, respectively, as of September 30, 2002. The plan has no assets.

The assumed healthcare trend rate has a significant effect on the amounts reported for the healthcare plans. A one-percentage-point change in the assumed healthcare trend rate would have the following effects:

WGL Holdings, Inc.
Washington Gas Light Company
Part II
Item 8. Financial Statements and Supplementary Data (continued)
Notes to Consolidated Financial Statements (continued)

Healthcare Trends

(In millions)	1-Percentage-Point Increase	1-Percentage-Point Decrease
Increase (decrease) total service and interest cost components	$ 5.3	$ (4.0)
Increase (decrease) post-retirement benefit obligation	$ 50.8	$ (37.2)

A significant portion of the estimated post-retirement medical and life insurance benefits apply to the Company's regulated activities.

The Public Service Commission of the District of Columbia (PSC of DC) granted the recovery of post-retirement medical and life insurance benefit costs determined in accordance with GAAP through a five-year phase-in plan that ended September 30, 1998. The regulated utility deferred the difference generated during the phase-in period as a regulatory asset. Effective October 1, 1998, the PSC of DC granted the regulated utility full recovery of costs determined under GAAP, plus a fifteen-year amortization of the regulatory asset established during the phase-in period.

On September 28, 1995, the State Corporation Commission of Virginia (SCC of VA) issued a generic order that allowed the regulated utility to recover most costs determined under GAAP in rates over twenty years. The SCC of VA, however, set a forty-year recovery period of the transition obligation. As prescribed by GAAP, the regulated utility amortizes these costs over a twenty-year period.

The Public Service Commission of Maryland (PSC of MD) has not rendered a decision that specifically addresses recovery of post-retirement medical and life insurance benefit costs determined in accordance with GAAP. However, the PSC of MD has approved a level of rates sufficient to recover the costs determined under GAAP.

Post-retirement medical and life insurance benefit costs deferred as a regulatory asset at September 30, 2003 and 2002 were $6.6 million and $7.2 million, respectively. The regulated utility expects that these costs will be recovered over a twenty-year period that began October 1, 1993.

Each regulatory commission having jurisdiction over the regulated utility requires it to fund amounts reflected in rates for post-retirement medical and life insurance benefits to irrevocable trusts. The expected long-term rate of return on the assets in the trusts was 8.25 percent for fiscal years 2003, 2002 and 2001. The regulated utility assumes a 39.6 percent income tax rate to compute taxes on the taxable portion of the income in the trusts.

13. STOCK-BASED COMPENSATION

The Company and its subsidiaries periodically provide compensation in the form of common stock to certain employees and Company directors. The Company designed its stock-based compensation plans to promote its long-term success by attracting, recruiting and retaining key employees, and providing certain

CH ENERGY GROUP INC

Filing Type: 10-K
Description: N/A
Filing Date: 12/31/03

Ticker: CHG
Cusip: 12541M
State: NY
Country: US
Primary SIC: 4911
Primary Exchange: NYS
Billing Cross Reference:
Date Printed: 04/13/04

Debt Covenants

Central Hudson's $75 million credit facility requires that Central Hudson maintain certain financial ratios and contains other restrictive covenants. Currently, Central Hudson is in compliance with all of its debt covenants. The only debt outstanding at CHEC is amounts borrowed from Energy Group. As of December 31, 2003, no amounts were outstanding on CHEC's line of credit with its commercial bank and, accordingly, it is in compliance with all of its debt covenants.

NOTE 10 - POST-EMPLOYMENT BENEFITS

Pension Benefits

Central Hudson has a non-contributory Retirement Income Plan ("Retirement Plan") covering substantially all of its employees. The Retirement Plan is a defined benefit plan, which provides pension benefits that are based on the employee's compensation and years of service. It has been Central Hudson's practice to provide periodic updates to the benefit formula stated in the Retirement Plan.

In September 2003, Central Hudson contributed $10 million to the Trust Fund for the Retirement Plan to reduce the difference between the Accumulated Benefit Obligation ("ABO") for the Retirement Plan and the market value of related pension assets. In accordance with SFAS No. 87, Employers Accounting for Pensions ("SFAS 87"), Central Hudson was required to show a minimum pension liability of $3.9 million on its balance sheet for the difference between the ABO and the market value of the pension assets. In order to reflect this minimum pension liability of $3.9 million, Central Hudson was required to record a pension accrual of $106.9 million that additionally offsets the prefunded pension costs balance of $103 million at December 31, 2003. The offsetting charge on the balance sheet was recorded as an intangible asset in the amount of $24.4 million representing unrecognized prior service costs and the remainder of $82.5 million as a regulatory asset as authorized by the PSC.

For the balance sheet presentation, the prefunded pension costs of $103 million were offset against total accrued pension costs of $112.8 million. The resulting pension liability of $9.8 million at December 31, 2003, also includes $5.9 million for non-qualified executive plans. The balance of the pension related regulatory asset of $124.2 million reflects a $1.1 million SFAS 87 adjustment for non-qualified executive plans and undercollected pension costs of $40.6 million to be recovered from customers.

Under the policy of the PSC regarding pension costs, differences between pension expense and rate allowances covering pension expenses are deferred for future recovery from or return to customers and carrying charges accrued on cash differences. The $10 million contribution is subject to such carrying charges.

It should be noted that the valuation of the ABO was determined as of the measurement date of September 30, 2003, using a 6.0% discount rate (as determined with reference to interest rates applicable to domestic long-term corporate bonds rated "AA" by Moody's Investors Services, Inc.) and that each 0.25% change in the discount rate would affect the projection of ABO by approximately $8.0 million. The discount rate on the prior measurement date of September 30, 2002, was 6.75%.

Declines in the market value of the Trust Fund's investment portfolio and a reduction in the discount rate used to determine the ABO have resulted in a significant increase in annual pension expense as compared to the level upon which current rates were set. This difference is deferred under the PSC's policy for recovery of pension expense and post-retirement benefits. This deferral, which Central Hudson anticipates will continue in the future, could result in the accumulation of a significant regulatory asset which Central Hudson will seek to recover from customers as provided for under the PSC's policy.

Central Hudson accounts for pension activity in accordance with PSC-prescribed provisions which, among other things, require ten-year amortization of actuarial gains and losses. The pension assets and liabilities transferred to Dynegy as a result of the sale of Central Hudson's interests in the Danskammer Plant and the Roseton Plant were reflected in the amount recorded in 2001 for net periodic pension cost.

In addition to the Retirement Plan, Central Hudson's and Energy Group's officers and executives are covered under a non-qualified Directors and Executives Deferred Compensation Plan and a non-qualified Supplementary Retirement Plan. Central Hudson also sponsors a non-qualified Retirement Benefit Restoration Plan.

Other Post-Retirement Benefits

Central Hudson provides certain health care and life insurance benefits for retired employees through its post-retirement benefit plans. Substantially all of Central Hudson's employees may become eligible for these benefits if they reach retirement age while employed by Central Hudson. These and similar benefits for active employees are provided through insurance companies whose premiums are based on the benefits paid during the year. In order to reduce the total costs of these benefits, Central Hudson requires employees who retired on or after October 1, 1994, to contribute toward the cost of these benefits.

Central Hudson is fully recovering its net periodic post-retirement costs in accordance with PSC guidelines. Under these guidelines, the difference between the amounts of post-retirement benefits recoverable in rates and the amounts of post-retirement benefits determined by an actuary under SFAS 106, Employers Accounting for Post-retirement Benefits Other Than Pensions, is deferred as either a regulatory asset or liability, as appropriate.

Estimates of Long-Run Rates of Return

An equal weighted average of three methods was used to estimate the long-run expected returns of each equity asset class. The three methods were: 1) the building block method, based on the Capital Asset Pricing Model, which states that the return of an asset class is a function of the risk-free rate and a risk based return premium; 2) the historical return method, which uses the historical average return for each market index as a proxy for future average returns; and 3) the economic growth method, which is based on long-run averages on estimates for economic growth, dividend yield, and expected inflation.

For the fixed income asset class, three methods were used. The historical return and building block methods, described above, and the market observable rate of return, represented by the average yield to maturity of representative market indexes.

For the real estate asset class, the historical return and building block method, described above, were used to estimate the long-run expected return.

Retirement Plan Policy and Strategy

Central Hudson's Retirement Plan seeks to match the long-term nature of its funding obligations with investment objectives for long-term growth and income. Retirement Plan assets are invested in accordance with sound investment practices that emphasize long-term investment fundamentals. The Retirement Plan recognizes that assets are exposed to risk and the market value of assets may vary from year to year. Potential short-term volatility, mitigated through a well-diversified portfolio structure, is acceptable in accordance with the objective of capital appreciation over the long-term.

It is desired that the Retirement Plan earn returns higher than the market, as represented by a benchmark index comprised of 30% Standard & Poor's 500 Stock Index, 10% Russell 2000 Stock Index, 20% Morgan Stanley Capital International Europe, Australasia, and Far East (MSCI EAFE) International Stock Index, 5% NCREIF Real Estate Composite Index, and 35% Merrill Lynch Domestic Master Bond Index. The Retirement Plan is expected to exceed the average annual return of this benchmark on a risk-adjusted basis over a three-to-five-year rolling time period and a full market cycle. It is understood that there can be no guarantees about the attainment of the Retirement Plan's return objectives.

The asset allocation strategy employed in the Retirement Plan reflects Central Hudson's return objectives and risk tolerance. Asset mix targets, expressed as a percentage of the market value of the Retirement Plan, are summarized in the table below:

Asset Class	Minimum	Target Average	Maximum
Domestic Large/Medium Capitalization Stocks	28%	33%	38%
Domestic Small/Medium Capitalization Stocks	9%	12%	15%
International Equity	10%	15%	20%
Real Estate	0%	5%	7%
Fixed Income	30%	35%	40%
Cash and Cash Equivalents	0%	0%	10%

Due to the dynamic nature of market value fluctuations, Retirement Plan assets will require rebalancing from time to time to maintain the target asset mix. The Retirement Plan recognizes the importance of maintaining a long-term strategic mix and does not intend any tactical asset allocation or market timing asset mix shifts.

The Retirement Plan will utilize multiple managers and funds of complementary investment styles and asset classes to invest plan assets.

As of December 31, 2003, the only post-retirement benefit plans provided to employees of any of the competitive business subsidiaries were Griffith's 401(k) Savings and Profit Sharing plan and SCASCO's 401(k) Savings and Profit Sharing plan.

Reconciliations of Central Hudson's pension and other post-retirement plans' benefit obligations, plan assets, and funded status, as well as the components of net periodic pension cost and the weighted average assumptions (excluding competitive business subsidiary employees not covered by these plans) are as follows:

	Pension Benefits		Other Benefits	
	2003	2002	2003	2002
	(In Thousands)		(In Thousands)	
Change in Benefit Obligation:				
Benefit obligation at beginning of year	$ 314,467	$ 273,381	$ 111,177	$ 85,081
Service cost	5,942	5,404	2,860	2,242
Interest cost	20,961	20,553	8,643	7,041
Participant contributions	--	--	259	238
Plan amendments	6,017	--	--	--
Benefits paid	(18,342)	(17,967)	(5,099)	(4,609)
Actuarial loss	33,398	33,096	38,098	21,184
Benefit Obligation at End of Year	$ 362,443	$ 314,467	$ 155,938	$ 111,177
Change in Plan Assets:				
Fair value of plan assets at beginning of year	$ 287,354	$ 291,288	$ 58,833	$ 64,588
Actual return on plan assets	39,433	(15,787)	10,950	(6,720)
Employer contributions	10,289	32,283	5,700	5,700
Participant contributions	--	--	259	238
Benefits paid	(18,342)	(17,967)	(5,099)	(4,609)
Administrative expenses	(2,017)	(2,463)	(320)	(364)
Fair Value of Plan Assets at end of Year	$ 316,717	$ 287,354	$ 70,323	$ 58,833

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(In Thousands)	Pension Benefits 2003	Pension Benefits 2002	Other Benefits 2003	Other Benefits 2002
Reconciliation of Funded Status:				
Funded Status	$ (45,727)	$ (27,114)	$(85,616)	$(52,344)
Unrecognized actuarial loss	119,755	111,146	52,042	22,260
Unrecognized transition obligation	--	--	23,079	25,644
Unamortized prior service cost	24,279	19,966	(66)	(74)
Accrued Benefit Cost	$ 98,307	$ 103,998	$(10,561)	$ (4,514)
Amounts Recognized on Consolidated Balance Sheet:				
Prepaid benefit cost	$ --	$ 108,242	$ --	$ --
Accrued benefit liability	(9,775)	(4,244)	(10,561)	(4,514)
Intangible asset	24,447	--	--	--
Regulatory asset	83,635	--	--	--
Net Amount Recognized at End of Year	$ 98,307	$ 103,998	$(10,561)	$ (4,514)
Components of Net Periodic Benefit Cost:				
Service cost	$ 5,942	$ 5,404	$ 2,860	$ 2,242
Interest cost	20,961	20,553	8,643	7,041
Expected return on plan assets	(21,410)	(22,698)	(4,596)	(4,200)
Amortization of prior service cost	1,706	1,716	(9)	(9)
Amortization of transitional (asset) or obligation	--	(152)	2,566	2,566
Recognized actuarial loss or (gain)	8,780	(1,599)	2,693	(1,068)
Net Periodic Benefit Cost	$ 15,979	$ 3,224	$ 12,157	$ 6,572
Weighted-average assumptions used to determine benefit obligations at December 31:				
Discount rate	6.00%	6.75%	6.00%	6.75%
Expected long-term rate of return on plan assets	8.00%	8.50%	7.75%	8.25%
Rate of compensation increase	4.50%	4.50%	4.50%	4.50%
Weighted-average assumptions used to determine net periodic benefit cost for years ended December 31:				
Discount rate	6.75%	7.25%	6.75%	7.25%
Expected long-term rate of return on plan assets	8.50%	8.50%	8.25%	6.80%
Rate of compensation increase	4.50%	4.50%	4.50%	4.50%

Pension plans with accumulated benefit obligations in excess of plan assets:				
Projected benefit obligation	$ 362,443	$ 5,398	$ --	$ --
Accumulated benefit obligation	326,413	4,624	--	--
Fair Value of plan assets	316,717	--	--	--

The accumulated benefit obligation for defined benefit pension plans was $326.4 million and $287.2 million at December 31, 2003 and December 31, 2002, respectively.

Central Hudson's pension and other post-retirement plans' weighted average asset allocations at December 31, 2003, and 2002 by asset category are as follows:

	Pension Benefits		Other Benefits	
	2003	2002	2003	2002
Equity Securities	61.6%	59.8%	62.0%	57.3%
Debt Securities	30.5%	32.3%	35.1%	40.5%
Real Estate	6.7%	7.0%	--	--
Other	1.2%	0.9%	2.9%	2.2%
Total:	100%	100%	100%	100%

For the pension plan and other benefit plan, equity securities include no Energy Group common stock at December 31, 2003 and 2002, respectively.

Central Hudson does not expect to make a contribution to the pension plan in 2004, and expects to make a contribution of approximately $5.6 million to its other post-retirement plan. The non-qualified supplementary Retirement Plan and Retirement Benefit Restoration Plan are not pre-funded. Cash required to pay benefits for participants in these plans during 2004 is expected to total $0.4 million.

For measurement purposes, an 11.5% (12.0% for participants over age 65) annual rate of increase in the per capita cost of covered health benefits was assumed for 2004. The rate is assumed to decrease gradually to 5.0% for 2013 and remain at that level thereafter.

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plan. A one percentage point (1%) change in assumed health care cost trend rates would have the following effects:

	One Percentage Point Increase	One Percentage Point Decrease
Effect on total of service and interest cost components for 2003	$ 1,687,000	$ (1,466,000)
Effect on year-end 2003 post-retirement benefit obligation	$20,428,000	$(18,062,000)

NOTE 11 - STOCK-BASED COMPENSATION INCENTIVE PLANS

Energy Group's Long-Term Performance-Based Incentive Plan ("Incentive Plan"), adopted in 2000 and amended in 2001 and 2003, reserves 500,000 shares of the Energy Group's common stock for awards to be granted under the Incentive Plan. The Incentive Plan provides for the granting of stock options, stock appreciation rights, restricted stock awards, performance shares, and performance units. No participant may be granted total awards in excess of 150,000 shares over the life of the Incentive Plan. Stock options granted to officers of Energy Group and its subsidiaries are exercisable over a period of ten years, with 40% of the options vesting after two years and 20% each year thereafter for the following three years; however, stock options granted to executives retiring prior to June 30, 2006, are immediately exercisable upon retirement. Additionally, stock options granted to non-employee directors are immediately exercisable.

In the third quarter of 2003, the Incentive Plan was amended. The amendment allows executives to defer receipt of performance shares and performance units. Also, an amendment to the Stock Plan for Outside Directors provides for shares of stock previously accrued for retired directors to be paid in the form of cash, and provided that active directors could elect to transfer previously accrued shares payable to them to Energy Group's Directors and Executives Deferred Compensation Plan.

Effective January 1, 2000, stock options covering 30,300 shares were granted with an exercise price per share of $31.94. Further, effective January 1, 2001, stock options covering 59,900 shares were granted with an exercise price per share of $44.06. There were no options granted in 2002. Effective January 1, 2003, stock options covering a total of 36,900 shares were granted with an exercise price per share of $48.62.

REQUEST FOR INFORMATION TO THE DEPARTMENT OF DEFENSE BY

THE COMMISSION STAFF

First Data Request - Question No. 3

Responding Witness: Thomas J. Prisco

Q-3. Refer to the Prisco Testimony, page 12, concerning LG&E's proposed storm damage normalization. Was Mr. Prisco aware that in previous LG&E rate cases the Commission has included the use of an inflation factor in the calculation of the adjustment? Explain the response.

A-3. Yes. However, Mr. Prisco believes the merger has made LG&E more efficient in its overall operation including its ability and resources used to respond to emergencies. Applying an inflation factor to storm damage costs, which were incurred in the early years of the merger, denies customers any cost benefit derived from the joint company.

REQUEST FOR INFORMATION TO THE DEPARTMENT OF DEFENSE BY

THE COMMISSION STAFF

First Data Request - Question No. 4

Responding Witness: Thomas J. Prisco

Q-4. Refer to the Prisco Testimony, page 12, concerning the Earnings Sharing Mechanism ("ESM") audit expenses. Was Mr. Prisco aware that, under the provisions of KRS 278.255(3), the costs of the ESM audit must be included in the cost of service of LG&E for rate-making purposes? Explain the response.

A-4. Yes. Mr. Prisco included the ESM audit expense in the cost of service.

Q-5. Refer to the Prisco Testimony, Exhibit TJP-2.

a. Concerning the Accounts Receivable Securitization component of LG&E's capitalization and capital structure:

(1) Was Mr. Prisco aware that the Accounts Receivable Securitization program was terminated on January 16, 2004?

(2) Was Mr. Prisco aware that LG&E replaced the funds from the Accounts Receivable Securitization program with a mix of short-term and long-term debt borrowed from Fidelia, Inc. ("Fidelia") in January 2004?

(3) Explain why Mr. Prisco believes the Accounts Receivable Securitization program should be included as part of LG&E's capital structure in this case.

(4) Should the Fidelia debt financing be recognized in the capital structure of LG&E, but the dollars of capitalization remain unchanged from the total as of test-year end? Explain the response.

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b. Concerning the Common Equity component of LG&E's capitalization and capital structure, does Mr. Prisco agree with LG&E's proposed adjustment to Common Equity related to its minimum unfunded pension liability currently reported in the Other Comprehensive Income balance? Explain the response.

A-5a (1). Yes

A-5a (2). Yes

A-5a (3). Mr. Prisco used the end of the test period capital structure, proposed by LG&E, for calculation purposes only. His use does not constitute an endorsement of LG&E's position.

A-5a (4). See answer to 5a (3).

A-5b. See answer to 5a (3).

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Response to Initial Data Request by Commission Staff

Question No. 6

Responding Witness: Kenneth L. Kincel

Q.2. Refer to Direct Testimony of Kenneth L. Kincel ("Kincel Testimony"), page 11 and Exhibit KLK-6. Are the dividends listed in the exhibit adjusted for changes in the dividends paid during the 12-month period? If the dividends are not adjusted, explain why?

A.2. See DOD Response to LG&E, Question No. 2(b) and 2(c) for a full explanation as to how the expected dividends were calculated. Dividends for the last 12-month period were not adjusted because one full year of growth was applied to determine next year's dividend and yield. If, for example, the last declared or paid dividend was "annualized" by multiplying by 4 to get an estimate of the current dividend rate, then only one-half of the annual growth rate would be applied to determine the dividend for the next year. Both are reasonable approaches for determining the expected yields over the next year when there is no disruption in the dividends paid over the last 12-month period. As can be seen in the ***Value Line*** reports for the electric utility comparable group (see DOD Response to LG&E, Question No. 1), and the dividend data from the ***Yahoo Finance*** Historical Quotes database for the natural gas utility comparable group (see DOD Response to LG&E, Question No. 2(b)), there was no disruption in dividends paid over the most recent 12-month period for any of the utilities used in the comparable groups.

U. S. Department of Defense

Case No. 2003-00433

Response to Initial Data Request by Commission Staff

Question No. 7

Responding Witness: Kenneth L. Kincel

Q.2. The Kincel Testimony, page 13, states that Ibbotson Associated were relied upon for the methodology used to apply the Capital Asset Pricing Model ("CAPM"). Provide a copy of the Ibbotson Associates methodology.

A.2. See attached extract from Chapter 4 and the final summary page of ***Stocks, Bonds, Bills and Inflation, Valuation Edition 2003 Yearbook***, by Ibbotson Associates.

Stocks, Bonds, Bills, and Inflation

SBBI

Valuation Edition
2003 Yearbook

IbbotsonAssociates

Chapter 4

Overview of Cost of Equity Capital Models

There are many methods for calculating the equity cost of capital. Chapter 3 discusses the buildup method for estimating the equity cost of capital. Other popular methods of calculation include the capital asset pricing model (CAPM), the discounted cash flow (DCF) method, arbitrage pricing theory (APT), and the Fama-French three factor model.

The Capital Asset Pricing Model

The capital asset pricing model (CAPM) is a simple and elegant model that describes the expected (future) rate of return on any security or portfolio of securities. It is among the most widely used techniques to estimate the cost of equity. The CAPM resulted from the efforts of three recipients of the Nobel Memorial Prize in Economic Science: Harry M. Markowitz, James Tobin, and William F. Sharpe. The Nobel committee cited the contributions to the CAPM of Tobin and Markowitz when awarding the prizes to both men. Sharpe's work on the model was the primary reason for which he won the Nobel Prize.

Systematic Risk

The principal insight of the CAPM is that the expected return on an asset is related to its risk; that is, risk-taking is rewarded. The model assumes that there is a riskless rate of return that can be earned on a hypothetical investment with returns that do not vary. A risky investment (one with returns that vary from one period to the next) will provide the investor with a reward in the form of a risk premium—an expected return higher than the riskless rate. For a particular risky investment, the CAPM indicates that the size of the risk premium is proportionate, in a linear fashion, to the amount of systematic risk taken.

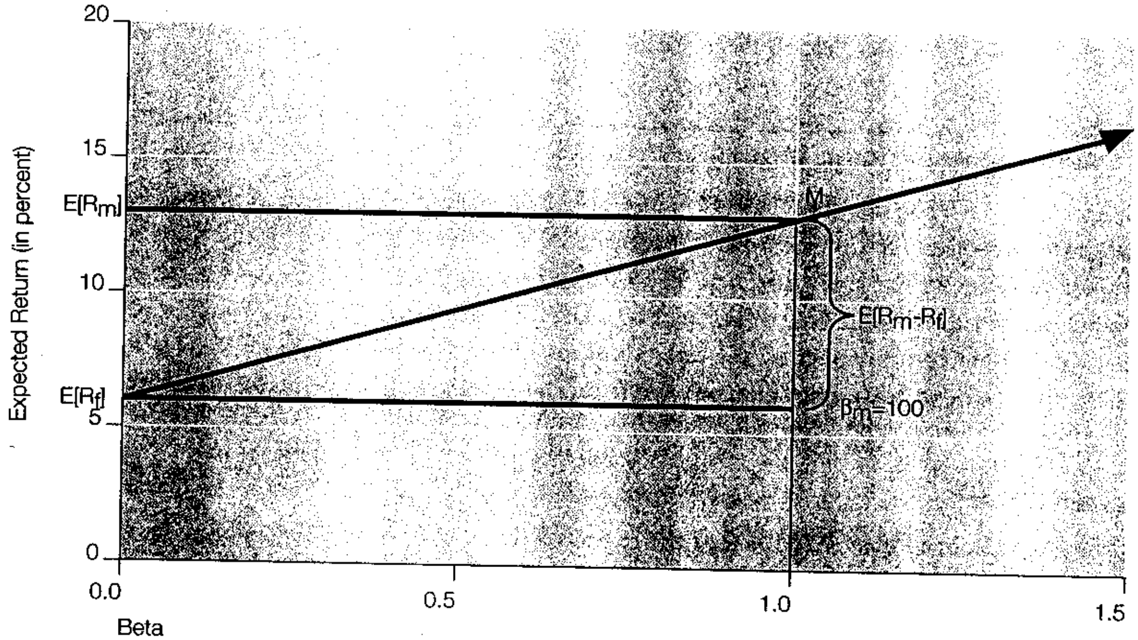
The CAPM breaks up the total risk (the variability of returns) of an investment into two parts: systematic risk and unsystematic risk. Systematic risk is unavoidable and pervades (to a greater or lesser degree) every asset in the real economy and every claim (such as a stock) on those assets. Systematic risk generally springs from external, macroeconomic factors that affect all companies in a particular fashion, albeit with different magnitudes. The CAPM concludes that taking systematic risk is rewarded with a risk premium. The size of the risk premium is proportionate to the degree of co-movement of the security or portfolio (called beta) with the market portfolio consisting of all risky assets.

In contrast, unsystematic risk is that portion of total risk that can be avoided through diversification. The CAPM concludes that unsystematic risk is not rewarded with a risk premium. For example, the possibility that a firm will lose market share to a competitor is a source of unsystematic risk for its stock. (See Chapter 6 for additional information on beta and systematic risk.)

The security market line represents the relationship between expected return and systematic risk. This linear relationship forms the security market line, which is depicted in Graph 4-1.

Graph 4-1

The Security Market Line



The riskless asset forms the y-intercept of the security market line and represents the expected return on the asset with no systematic risk (beta equal to zero). The market portfolio by definition has a beta of one. Drawing a line that passes through the riskless asset and the market portfolio forms the security market line. Theoretically, to be fairly priced, every stock or portfolio of stocks should fall on the line.[1]

The relationship between systematic risk and expected return can also be expressed mathematically. The CAPM describes the cost of equity for any company's stock as equal to the riskless rate plus an amount proportionate to the systematic risk an investor assumes.

$$k_s = r_f + (\beta_s \times ERP)$$

where:

k_s = the cost of equity for company s;

r_f = the expected return of the riskless asset;

β_s = the beta of the stock of company s; and

ERP = the expected equity risk premium, or the amount by which investors expect the future return on equities to exceed that on the riskless asset.

Since the CAPM has only three variables—the expected return on the riskless asset, the beta of the stock, and the expected equity risk premium—it is one of the easiest models to implement in practice.

1 This relationship does not seem to hold empirically with small company stocks. This size effect is discussed in Chapter 7.

However, an estimate of each of the above three variables must be formed. Like all components of the cost of capital, these variables should be measured on a forward-looking basis. Chapters 5 and 6 are devoted to estimating the equity risk premium and beta, respectively. Factors to consider in estimating the riskless rate are covered below.

Risk-Free Rate

The CAPM implicitly assumes the presence of a single riskless asset, that is, an asset perceived by all investors as having no risk. A common choice for the nominal riskless rate is the yield on a U.S. Treasury security. The ability of the U.S. government to create money to fulfill its debt obligations under virtually any scenario makes U.S. Treasury securities practically default-free. While interest rate changes cause government obligations to fluctuate in price, investors face essentially no default risk as to either coupon payment or return of principal.

The horizon of the chosen Treasury security should match the horizon of whatever is being valued. When valuing a business that is being treated as a going concern, the appropriate Treasury yield should be that of a long-term Treasury bond. Note that the horizon is a function of the investment, not the investor. If an investor plans to hold stock in a company for only five years, the yield on a five-year Treasury note would not be appropriate since the company will continue to exist beyond those five years.

In February of 1977 the Treasury began to issue 30-year Treasury securities. Prior to this date, the longest-term Treasury security was 20 years. To remain consistent with Ibbotson's historical data series, the *Stocks, Bonds, Bills, and Inflation Yearbook* continues to base the yield for its long-term government bond on one with close to 20 years to maturity. In recent years the Treasury ceased offering 30-year securities, however. As long as there are bonds being traded with at least 20 years to maturity, there will be a proxy for the yield on 20 year Treasury securities. It would not be for a number of years from now that lack of data may become an issue. Currently, the longest term security offered by the Treasury is 10 years. Differences in the yields of these long-term instruments tend to be very small. Therefore, it would be appropriate to use either maturity bond to represent a long-term riskless rate. Table 4-1 shows the current yields for several different horizons.

Table 4-1

Current Yields or Expected Riskless Rates
December 31, 2002

	Yield (Riskless Rate)*
Long-Term (20-year) U.S. Treasury Coupon Bond Yield	4.8%
Long-Term (10-year) U.S. Treasury Coupon Bond Yield	3.8%
Intermediate-Term (5-year) U.S. Treasury Coupon Note Yield	2.6%
Short-term (30-day) U.S. Treasury Bill Yield	1.2%

*Maturities are approximate.

Should the yield on a Treasury bond or a Treasury strip be used to represent the riskless rate? In most cases the yield on a Treasury coupon bond is most appropriate. If the asset being measured spins off cash periodically, the Treasury bond most closely replicates this characteristic. On the other hand, if the asset being measured provides a single payoff at the end of a specified term, the yield on a Treasury Strip would be more appropriate.

CAPM Modified for Firm Size

One of the important characteristics not necessarily captured by the Capital Asset Pricing Model is what is known as the size effect. This is discussed in detail in Chapter 7. The need for this premium when using the CAPM arises because, even after adjusting for the systematic (beta) risk of small stocks, they outperform large stocks. The betas for small companies tend to be greater than those for large companies; however, these higher betas do not account for all of the risks faced by those who invest in small companies.[2] This premium can be added directly to the results obtained using the CAPM:

$$k_s = r_f + (\beta_s \times ERP) + SP_s$$

where all of the variables are as given in the previous section on the CAPM and SP_s is the appropriate size premium based on the firm's equity market capitalization. The market capitalization of company s will determine the relevant size premium: mid-cap, low-cap, or micro-cap.

Suppose we wish to calculate the cost of equity for a small electric utility company. To better account for both the industry risk and the firm size, we wish to use the modified CAPM approach. The company has a market capitalization of $135 million and falls within the micro-cap size group. Assume that the beta of the company is 0.53. The key variables for calculating the cost of equity using this size-premium-adjusted CAPM are:

Risk-free rate	= 4.8 percent
Expected equity risk premium	= 7.0 percent
The appropriate size premium	= 3.5 percent

Using the modified CAPM equation, the cost of equity for the electric utility company is:

$$k_s = r_f + (\beta_s \times ERP) + SP_s = 4.8\% + (0.53 \times 7.0\%) + 3.5\% = 12.0\%$$

The beta-adjusted size premium is the most appropriate for use with this model. Please note that the size premia commonly referred to in this publication are the beta-adjusted size premia, unless stated otherwise. The non-beta-adjusted size premia already account for the added return generally attributed to the higher betas of small companies. The non-beta-adjusted size premium makes the assumption that the beta of the company is the same as that of the small stock portfolio. If the non-beta-adjusted size premium is used in the context of the modified CAPM equation above, the effect of beta on return will essentially be counted double. Multiplying the equity risk premium by another measure of beta (either the company beta or industry beta) introduces to the same equation a duplicate, though possibly different, measure of systematic risk.[3]

2 In general, small company betas are expected to be higher than large company betas. This, however, does not hold for all time periods. Chapter 6 discusses in more detail the measurement of beta for small stocks.

3 The beta-adjusted size premia are different from the small stock premia (or non-beta-adjusted size premia) shown in previous editions of the *Stocks, Bonds, Bills, and Inflation Yearbook* (prior to the *1995 Yearbook*). The small stock premium reported in older editions of *Stocks, Bonds, Bills, and Inflation* is the difference in long-term average returns between the large company stock total return series (currently represented by the S&P 500) and the small company stock total return series (currently represented by the Dimensional Fund Advisors U.S. Micro Cap Portfolio). The size premia given here are based on slightly different baskets of stocks from the CRSP (Center for Research in Security Prices) data set and, more importantly, they are adjusted for beta. That is, small stocks do have higher betas than large stocks; the return, above what might be expected because of the higher betas, is the size premium. These size premia increase as the capitalization of the company decreases. Chapter 7 describes the development of these premia in more detail.

Key Variables in Estimating the Cost of Capital

	Value
Yields (Riskless Rates)[1]	
Long-term (20-year) U.S. Treasury Coupon Bond Yield	4.8%
Intermediate-term (5-year) U.S. Treasury Coupon Note Yield	2.6
Short-term (30-day) U.S. Treasury Bill Yield	1.2
Equity Risk Premium[2]	
Long-horizon expected equity risk premium: large company stock total return minus long-term government bond income returns	7.0
Intermediate-horizon expected equity risk premium: large company stock total returns minus intermediate-term government bond income returns	7.4
Short-horizon expected equity risk premium: large company stock total returns minus U.S. Treasury bill total returns	8.4

Size Premium[3]

Decile	Market Capitalization of Smallest Company (in millions)		Market Capitalization of Largest Company (in millions)	Size Premium (Return in Excess of CAPM)
Mid-Cap, 3-5	$1,144.452	-	$5,012.705	0.82%
Low-Cap, 6-8	$314.174	-	$1,143.845	1.52
Micro-Cap, 9-10	$0.501	-	$314.042	3.53
Breakdown of Deciles 1-10				
1-Largest	$11,636.618	-	$293,137.304	-0.32
2	$5,018.316	-	$11,628.735	0.42
3	$2,686.479	-	$5,012.705	0.66
4	$1,691.463	-	$2,680.573	0.95
5	$1,144.452	-	$1,691.210	1.16
6	$791.917	-	$1,143.845	1.48
7	$521.400	-	$791.336	1.35
8	$314.174	-	$521.298	2.06
9	$141.529	-	$314.042	2.56
10-Smallest	$0.501	-	$141.459	5.67
Breakdown of the 10th Decile				
10a	$64.798	-	$141.459	3.98
10b	$0.501	-	$64.767	9.16

[1] As of December 31, 2002. Maturities are approximate.

[2] Expected risk premia for equities are based on the differences of historical arithmetic mean returns from 1926–2002 using the S&P 500 as the market benchmark.

[3] See chapter 7 for complete methodology.

Note: Examples on how these variables can be used are found in Chapters 3 and 4

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Response to Initial Data Request by Commission Staff

Question No. 8

Responding Witness: Kenneth L. Kincel

Q.2. The Kincel Testimony, pages 13 and 14, uses a 20-year government bond for his risk free rate in the risk premium analysis and the CAPM analysis. Explain why the 20-year bond is appropriate instead of a 20-year bond.

A.2. The reason for the use of a 20-year maturity bond is that 30-year Treasury securities have only been issued over the relatively recent past, starting in February of 1977, and have since been discontinued by the Treasury. As a result, the data series for risk premium created by Ibbotson Associates to measure the long horizon market risk premium since 1926 was based on the 20-year Treasury bond. This data series was used by Mr. Kincel in his analysis, and is part of the Ibbotson Associates' methodology described in DOD Response to Staff, Question No. 7. The use of yields for 30-year maturity bonds with the market long horizon risk premium of 7.0% calculated by Ibbotson Associates, which is based on 20-year Treasury yields, would have been mathematically inconsistent.

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Response to Initial Data Request by Commission Staff

Question No. 9

Responding Witness: Kenneth L. Kincel

Q.2. The Kincel Testimony, page 16, states that 90 days of average closing prices was used in his Discounted Cash Flow analysis. Explain why 90 days is an appropriate time period for use in this analysis.

A.2. The DCF model calls for use of the "current price" when calculating the return on common equity. Because of the recent volatility in market prices for utility stocks, Mr. Kincel averaged recent prices rather than just selecting the most recent single observation. The greater the period used for the averaging, the more so volatility is smoothed. However, too great a period of time means that one is moving too far from "current" prices. The use of 90 days is a compromise between these two competing objectives, a compromise made using Mr. Kincel's judgment.

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Response to Initial Data Request by Commission Staff

Question No. 10

Responding Witness: Kenneth L. Kincel

Q.2. The Kincel Testimony, page 15 and 20, recommends a Return on Equity ("ROE") of 10 percent for LG&E's electric operations and 10.5% for LG&E's gas operations, stating that these percentages are recommended in the interest of gradualism, since LG&E has a higher ROE.

a. Explain how these recommendations demonstrate the concept of gradualism.

b. If LG&E's current authorized ROE for electric operations was less than 11.5 percent, would Mr. Kincel's recommendation be less than 10 percent?

c. If LG&E's current authorized ROE for gas operations was less than 11.25 percent, would Mr. Kincel's recommendation be less than 10.5 percent?

A.2. See DOD Response to LG&E, Question No. 5.

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Response to Initial Data Request by Commission Staff

Question No. 11

Responding Witness: Kenneth L. Kincel

Q.2. Would Mr. Kincel's recommendation be the same if LG&E no longer had the ESM?

a. If yes, explain why.

b. If no, provide an estimate of the revised recommendation and explain why the absence of an ESM affects the recommendation.

A.2. Yes, Mr. Kincel's recommended ROE for both electric and natural gas operations is independent of the ESM, provided the "deadband" of the ESM is centered around Mr. Kincel's recommended values. Mr. Kincel is recommending the market-based required return on equity for LG&E after examining companies of comparable credit risk. The ESM removes some downside risk for the Company, by allowing ratepayer reimbursement of lost profits when extreme under-earning is experienced (a ROE below the deadband). However, it also removes some upside earnings potential, by requiring the sharing of "excess" profits due to extreme over-earning (a ROE above the deadband). Thus, if the "deadband" of the ESM is centered on Mr. Kincel's recommended, market-based ROE, there is no net risk adjustment to ROE that is necessary.