Cost of Short term Debt page 19.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 or 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Quarterly Period Ended June 30, 2003

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to

Commission File Number 1-14174

AGL RESOURCES INC.

(Exact name of registrant as specified in its charter)

Georgia	**58-2210952**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

Ten Peachtree Place, Atlanta, Georgia 30309
(Address and zip code of principal executive offices)
(Zip Code)

404-584-4000
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes X No __

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act). Yes X No __

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	Outstanding as of June 30, 2003
Common Stock, $5.00 Par Value	63,731,156

AGL RESOURCES INC.

Quarterly Report on Form 10-Q

For the Three and Six Months Ended June 30, 2003

TABLE OF CONTENTS

GLOSSARY OF KEY TERMS AND REFERENCED ACCOUNTING STANDARDS

AGLC	Atlanta Gas Light Company
AGL Capital	AGL Capital Corporation
AGL Networks	AGL Networks, LLC
AGL Resources	AGL Resources Inc. and its subsidiaries
AGSC	AGL Services Company
CGC	Chattanooga Gas Company
Corporate	Non-operating segment, which includes AGSC and AGL Capital
Credit Facility	Credit agreements supporting our commercial paper program
Distribution operations	Segment that includes AGLC, VNG and CGC
EBIT	A non-GAAP measure of Earnings Before Interest and Taxes - includes other income; as an indicator of our operating performance, EBIT should not be considered an alternative to, or more meaningful than, operating income as determined in accordance with GAAP
Energy investments	Segment that includes our investments in SouthStar, US Propane (and its investment in Heritage), AGL Networks and certain other companies
GAAP	Accounting principles generally accepted in the United States of America
Heritage	Heritage Propane Partners, L.P.
Marketers	Georgia Public Service Commission-certificated marketers selling retail natural gas in Georgia
Medium-Term notes	Notes issued by AGLC scheduled to mature in 2003 through 2027 bearing various interest rates ranging from 5.9% to 8.7%
NYMEX	New York Mercantile Exchange, Inc.
PUHCA	Public Utility Holding Company Act of 1935, as amended
SEC	Securities and Exchange Commission
Sequent	Sequent Energy Management, LP
SouthStar	SouthStar Energy Services, LLC
Trust Preferred Securities	Trust preferred securities subject to mandatory redemption
US Propane	US Propane, L.L.C.
VNG	Virginia Natural Gas, Inc.
Wholesale services	Segment that consists primarily of Sequent

APB 25	Accounting Principles Board of Opinion No. 25, "Accounting for Stock Issued to Employees"
EITF 98-10	EITF Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities"
EITF 00-11	EITF Issue No. 00-11, "Lessors' Evaluation of Whether Leases of Certain Integral Equipment Meet the Ownership Transfer Requirements of FASB Statement No. 13, *Accounting for Leases*, for Leases of Real Estate"
EITF 02-03	EITF Issue No. 02-03 "Accounting for Contracts Involved in Energy Trading and Risk Management Activities"
FIN 44	FASB Interpretation No. 44, "Accounting for Certain Transactions involving Stock Compensation"
FIN 45	FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others"
FIN 46	FASB Interpretation No. 46, "Consolidation of Variable Interest Entities"
SFAS 5	SFAS No. 5, "Accounting for Contingencies"
SFAS 66	SFAS No. 66, "Accounting for Sales of Real Estate"
SFAS 71	SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation"
SFAS 123	SFAS No. 123, "Accounting for Stock-Based Compensation"
SFAS 133	SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities"
SFAS 143	SFAS No. 143, "Accounting for Obligations Associated with the Retirement of Long-Lived Assets"
SFAS 148	SFAS No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure – an amendment of FASB Statement No. 123"
SFAS 149	SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities"
SFAS 150	SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity"

Item 1. Financial Statements

AGL RESOURCES INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(UNAUDITED)

In millions	June 30, 2003	December 31, 2002
Current assets		
Cash and cash equivalents	$3.3	$8.4
Receivables (less allowance for uncollectible accounts of $3.0 million at June 30, 2003 and $2.3 million at December 31, 2002)	286.7	373.1
Inventories	168.4	118.2
Unrecovered environmental response costs – current	23.8	21.8
Unrecovered pipeline replacement program costs – current	18.4	15.0
Energy marketing and risk management assets	11.6	24.7
Other current assets	4.5	25.2
Total current assets	516.7	586.4
Property, plant and equipment		
Property, plant and equipment	3,390.4	3,323.2
Less accumulated depreciation	1,165.6	1,129.0
Property, plant and equipment-net	2,224.8	2,194.2
Deferred debits and other assets		
Unrecovered pipeline replacement program costs	436.9	499.3
Goodwill	176.2	176.2
Unrecovered environmental response costs	155.3	173.3
Investments in equity interests	112.3	74.8
Unrecovered postretirement benefit costs	10.8	10.9
Other	24.9	26.9
Total deferred debits and other assets	916.4	961.4
Total assets	$3,657.9	$3,742.0

See Notes to Condensed Consolidated Financial Statements (Unaudited).

AGL RESOURCES INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(UNAUDITED)

In millions	June 30, 2003	December 31, 2002
Current liabilities		
Payables	$387.1	$341.8
Short-term debt	147.5	388.6
Current portion of long-term debt	95.3	30.0
Accrued pipeline replacement program costs – current	67.1	50.0
Accrued expenses	61.0	58.2
Accrued environmental response costs – current	48.4	41.3
Energy marketing and risk management liabilities	11.4	17.9
Other current liabilities	74.7	88.0
Total current liabilities	892.5	1,015.8
Accumulated deferred income taxes	344.3	320.0
Long-term liabilities		
Accrued pipeline replacement program costs	364.5	444.0
Accrued pension obligations	66.8	72.7
Accrued postretirement benefit costs	51.5	49.2
Accrued environmental response costs	37.5	63.7
Other	9.2	-
Total long-term liabilities	529.5	629.6
Deferred credits	70.6	72.3
Commitments and contingencies (Note 4)		
Capitalization		
Senior and Medium-Term notes	696.8	767.0
Trust Preferred Securities	228.3	227.2
Total long-term debt	925.1	994.2
Common shareholders' equity, $5 par value	895.9	710.1
Total capitalization	1,821.0	1,704.3
Total liabilities and capitalization	$3,657.9	$3,742.0

See Notes to Condensed Consolidated Financial Statements (Unaudited).

AGL RESOURCES INC. AND SUBSIDIARIES
CONDENSED STATEMENTS OF CONSOLIDATED INCOME
FOR THE THREE MONTHS AND SIX MONTHS ENDED JUNE 30, 2003 AND 2002
(UNAUDITED)

	Three Months Ended June 30,		Six Months Ended June 30,	
In millions, except per share amounts	2003	2002	2003	2002
Operating revenues	$186.6	$161.2	$539.1	$433.1
Cost of sales	45.4	24.4	194.0	121.5
Operating margin	141.2	136.8	345.1	311.6
Operating expenses				
Operation and maintenance expenses	69.9	65.2	142.1	135.4
Depreciation and amortization	22.7	22.5	45.0	45.6
Taxes other than income	7.7	7.2	15.6	14.7
Total operating expenses	100.3	94.9	202.7	195.7
Operating income	40.9	41.9	142.4	115.9
Other income	8.3	(1.7)	24.4	24.6
Interest expense and dividends on preferred securities	(18.2)	(21.2)	(38.1)	(43.9)
Earnings before income taxes	31.0	19.0	128.7	96.6
Income taxes	12.1	6.7	50.2	34.2
Income before cumulative effect of change in accounting principle	18.9	12.3	78.5	62.4
Cumulative effect of change in accounting principle, net of taxes	-	-	(7.8)	-
Net income	$18.9	$12.3	$70.7	$62.4
Basic earnings per common share:				
Income before cumulative effect of change in accounting principle	$0.30	$0.22	$1.27	$1.12
Cumulative effect of change in accounting principle	-	-	(0.13)	-
Basic	$0.30	$0.22	$1.14	$1.12
Diluted earnings per common share:				
Income before cumulative effect of change in accounting principle	$0.29	$0.22	$1.26	$1.11
Cumulative effect of change in accounting principle	-	-	(0.13)	-
Diluted	$0.29	$0.22	$1.13	$1.11
Weighted-average number of common shares outstanding:				
Basic	63.5	56.0	61.9	55.9
Diluted	64.2	56.5	62.4	56.2

See Notes to Condensed Consolidated Financial Statements (Unaudited).

AGL RESOURCES INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY
FOR THE SIX MONTHS ENDED JUNE 30, 2003
(UNAUDITED)

In millions, except per share amounts	Common shares	Premium on common shares	Earnings reinvested	Other comprehensive income	Shares held in treasury and trust	Total
Balance as of December 31, 2002	$289.0	$209.8	$279.8	($49.2)	($19.3)	$710.1
Comprehensive income:						
Net income	-	-	70.7	-	-	70.7
Total comprehensive income						70.7
Dividends on common shares ($0.27 per share)	-	-	(16.2)	-	-	(16.2)
Dividends on common shares ($0.28 per share)	-	-	(17.7)	-	-	(17.7)
Total dividends on common shares						(33.9)
Issuance of common shares						
Equity offering on February 14, 2003	32.2	104.5				136.7
Benefit, stock compensation, dividend reinvestment and share purchase plans	-	2.3	-	-	10.0	12.3
Total issuance of common shares						149.0
Balance as of June 30, 2003	$321.2	$316.6	$316.6	($49.2)	($9.3)	$895.9

See Notes to Condensed Consolidated Financial Statements (Unaudited).

AGL RESOURCES INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE SIX MONTHS ENDED JUNE 30, 2003 AND 2002
(UNAUDITED)

	Six Months Ended June 30,	
In millions	2003	2002
Cash flows from operating activities		
Net income	$70.7	$62.4
Adjustments to reconcile net income to net cash flow from operating activities		
Depreciation and amortization	45.0	45.6
Deferred income taxes	24.4	27.9
Cumulative effect of accounting change	12.6	-
Earnings in equity investments	(24.4)	(24.6)
Change in risk management assets and liabilities	(6.0)	1.0
Changes in certain assets and liabilities		
Receivables	86.4	(61.9)
Payables	45.3	108.8
Inventories	(50.2)	24.0
Other	0.9	18.1
Net cash flow provided by operating activities	204.7	201.3
Cash flows from investing activities		
Property, plant and equipment expenditures	(77.2)	(87.4)
Investment in equity interests	(20.0)	-
Cash received from equity investments	7.0	4.1
Other	6.0	0.1
Net cash flow used in investing activities	(84.2)	(83.2)
Cash flows from financing activities		
Payments and borrowings of short-term debt, net	(241.1)	(60.2)
Dividends paid on common shares	(31.8)	(26.4)
Equity offering	136.7	-
Sale of treasury shares	10.0	9.9
Payments of Medium-Term notes	-	(45.0)
Other	0.6	0.6
Net cash flow used in financing activities	(125.6)	(121.1)
Net decrease in cash and cash equivalents	(5.1)	(3.0)
Cash and cash equivalents at beginning of period	8.4	7.3
Cash and cash equivalents at end of period	$3.3	$4.3
Cash paid during the period for:		
Interest	$29.7	$37.6
Income taxes	$1.4	$11.2

See Notes to Condensed Consolidated Financial Statements (Unaudited).

AGL RESOURCES INC. AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

Significant Accounting Policies

General

Unless the context requires otherwise, references to "we", "us", "our" or the "company" are intended to mean consolidated AGL Resources Inc. and its subsidiaries (AGL Resources). We have prepared the accompanying unaudited consolidated financial statements under the rules of the Securities and Exchange Commission (SEC). Under such rules and regulations, we have condensed or omitted certain information and notes normally included in financial statements prepared in conformity with accounting principles generally accepted in the United States of America (GAAP). We believe, however, that our disclosures are adequate to make the information presented not misleading. The consolidated financial statements reflect all adjustments that are, in the opinion of management, necessary for a fair presentation of our financial results for the interim periods. You should read these condensed consolidated financial statements in conjunction with our consolidated financial statements and related notes included in our Annual Report on Form 10-K for the year ended December 31, 2002, filed with the SEC on March 19, 2003. Due to the seasonal nature of our business, the results of operations for the three and six months ended June 30, 2003 are not necessarily indicative of our results of operations to be expected for any other interim period or for the year ending December 31, 2003. For a glossary of key terms and referenced accounting standards, see the glossary on page three of this filing.

Basis of Presentation

Our consolidated financial statements include our accounts and those of our majority-owned and controlled subsidiaries. All significant intercompany items have been eliminated in consolidation. Certain amounts from prior periods have been reclassified to conform to the current presentation.

Accounting for Asset Retirement Obligations

In June 2001, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) 143, "Accounting for Obligations Associated with the Retirement of Long-Lived Assets," (SFAS 143), which is effective for fiscal years beginning after June 15, 2002. SFAS 143 requires legal obligations associated with the retirement of long-lived assets to be recognized at their fair value at the time that the obligations are incurred. Upon initial recognition of a liability, that cost should be recognized as an obligation and capitalized as part of the related long-lived asset. We adopted SFAS 143 on January 1, 2003, and it did not have a material impact on our financial position or results of operations because no legally enforceable retirement obligations were identified.

Our regulated entities currently accrue removal costs on many of our regulated, long-lived assets through depreciation expense, with a corresponding charge to accumulated depreciation, in accordance with rates approved by their state jurisdictions. As of June 30, 2003, we included accumulated removal costs of $103.9 million in our total accumulated depreciation.

Stock-based Compensation

We have several stock-based employee compensation plans and account for these plans under the recognition and measurement principles of Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" (APB 25) and related interpretations. For our stock option plans, we generally do not reflect stock-based employee compensation cost in net income, as options for those plans had an exercise price equal to the market value of the underlying common stock on the date of grant. However, if we subsequently modify the terms of the option granted we re-measure the intrinsic value of the options and record compensation expense in accordance with FASB Interpretation No. 44, "Accounting for Certain Transactions Involving Stock Compensation," when the market value of the underlying stock on the modification date is greater than the market value of the underlying stock on the original measurement date or grant date.

In December 2002, the FASB issued SFAS 148, "Accounting for Stock-Based Compensation – Transition and Disclosure – an amendment of FASB Statement No. 123" (SFAS 148). SFAS 148 provides alternative methods of transition for a voluntary change from other methods of accounting to the fair value based method of accounting for stock-based employee compensation. Under the fair value based method, compensation cost for stock options is measured when options are granted. In addition, SFAS 148 amends the disclosure requirements of SFAS 123 "Accounting for Stock-Based Compensation" (SFAS 123), which requires more prominent and more frequent disclosures in financial statements of the effects of stock-based compensation.

As of December 31, 2002, we adopted SFAS 148 through continued application of the intrinsic value method of accounting under APB 25, and we disclosed the effect on our net income and earnings per share of total stock-based employee compensation expense determined under the fair value based method. The following table illustrates the effect on our net income and earnings per share if we had instead applied the fair value recognition provisions of SFAS 123.

	Three Months Ended June 30,		Six Months Ended June 30,	
In millions, except per share amounts	2003	2002	2003	2002
Net income, as reported	$18.9	$12.3	$70.7	$62.4
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effect	0.1	0.4	0.2	1.8
Pro forma net income	$18.8	$11.9	$70.5	$60.6
Earnings per share:				
Basic-as reported	$0.30	$0.22	$1.14	$1.12
Basic-pro forma	$0.30	$0.21	$1.14	$1.08
Diluted-as reported	$0.29	$0.22	$1.13	$1.11
Diluted-pro forma	$0.29	$0.21	$1.13	$1.08

Comprehensive Income

Our comprehensive income includes net income and other gains and losses affecting shareholders' equity that GAAP excludes from net income. Such items consist primarily of unrealized gains and losses on certain derivatives and minimum pension liability adjustments. There were no such items during the six months ended June 30, 2003 and 2002, and as a result, our total comprehensive income was equal to net income.

Earnings per Common Share

We compute basic earnings per common share by dividing our income available to common shareholders by the weighted-average number of common shares outstanding daily. Diluted earnings per common share reflect the potential dilution that could occur when potential diluted common shares are added to common shares outstanding.

We derive our potential diluted common shares from performance units and stock options. The future issuance of the performance units depends on the satisfaction of certain performance criteria. The future issuance of outstanding stock options depends upon the exercise prices of the stock options, which are less than the average market price of the common shares for the respective periods. The following table shows our calculation of our diluted earnings per share.

In millions	Three Months Ended June 30, 2003	2002	Six Months Ended June 30, 2003	2002
Denominator for basic earnings per share (daily weighted-average shares outstanding)	63.5	56.0	61.9	55.9
Assumed exercise of performance units and stock options	0.7	0.5	0.5	0.3
Denominator for diluted earnings per share	64.2	56.5	62.4	56.2

Common Shareholders' Equity

On February 14, 2003, we announced the completion of our public offering of 6.4 million shares of common stock under our shelf registration statement. We priced the offering at $22.00 per share, and generated net proceeds of approximately $136.7 million, which we used to repay outstanding short-term debt and for general corporate purposes.

The following table provides details of our authorized, issued and outstanding common stock as of December 31, 2002 and June 30, 2003 and our common share activity during the six months ended June 30, 2003:

Shares in millions	Authorized	Issued	Treasury Shares	Outstanding
As of December 31, 2002	750.0	57.8	(1.1)	56.7
Three months ended March 31, 2003	-	6.4	0.2	6.6
Three months ended June 30, 2003	-	-	0.4	0.4
As of June 30, 2003	750.0	64.2	(0.5)	63.7

On April 16, 2003, we announced a 4% increase in our common stock dividend, raising the quarterly dividend from $0.27 per share to $0.28 per share, for an indicated annual dividend of $1.12 per share. Our new quarterly dividend became effective with the June 1, 2003 dividend that we paid to our shareholders of record as of the close of business on May 16, 2003.

The following table depicts the 6.4 million shares of common stock issued and the average price received as a result of our equity offering and the average issuance price of our stock out of treasury shares, under ResourcesDirect, our direct stock purchase and dividend reinvestment plan; our Retirement Savings Plus Plan; our Long-Term Stock Incentive Plan; our Long-Term Incentive Plan; and our Directors Plan.

In millions, except average issuance price	Six Months Ended June 30, 2003	2002
Equity offering	6.4	-
Issuance of treasury shares	0.6	0.6
Total common shares issued	7.0	0.6
Average issuance price of common shares	$21.99	$19.50

Other Income

Our other income consists of the following:

In millions	Three Months Ended June 30, 2003	2002	Six Months Ended June 30, 2003	2002
Equity in SouthStar's (1) earnings	$9.1	($1.1)	$23.5	$24.7
Equity in US Propane's (2) earnings	(0.5)	(0.6)	0.9	(0.1)
Allowance for funds used during construction	0.4	0.6	0.8	1.2
All other – net	(0.7)	(0.6)	(0.8)	(1.2)
Total other income	$8.3	($1.7)	$24.4	$24.6

(1) SouthStar Energy Services, LLC
(2) US Propane, L.L.C.

Recent Accounting Developments

In April 2003, the FASB issued SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" (SFAS 149). This statement amends and clarifies financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts (collectively referred to as derivatives) and for hedging activities under SFAS 133. Our adoption of SFAS 149 had no impact on our condensed consolidated financial statements.

In May 2003, the FASB issued SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity" (SFAS 150). This statement revises the accounting for certain financial instruments that, under previous guidance, issuers could account for as equity in a "mezzanine" section of the balance sheet between debt and equity. We adopted the provisions of SFAS 150 effective March 31, 2003, which required us to classify our Trust Preferred Securities initially at fair value as long-term liabilities in our Condensed Consolidated Balance Sheet.

Financial Instruments, Derivatives and Hedging Activities

SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133) established accounting and reporting standards requiring that every derivative financial instrument (including certain derivative instruments embedded in other contracts) be recorded in the balance sheet as either an asset or liability measured at its fair value. However, if the derivative transaction qualifies for and is designated as a normal purchase and sale, it is exempted from the fair value accounting requirements of SFAS 133 and is accounted for using traditional accrual accounting.

SFAS 133 requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. If the derivatives meet those criteria, SFAS 133 allows a derivative's gains and losses to offset related results on the hedged item in the income statement in the case of a fair value hedge, or to record the gains and losses in other comprehensive income until maturity in the case of a cash flow hedge, and requires that a company formally designate a derivative as a hedge as well as document and assess the effectiveness of derivatives associated with transactions that receive hedge accounting.

Interest Rate Swaps

In order to maintain a cost effective capital structure, it is our policy to borrow funds using a mix of fixed rate debt and variable rate debt. We have entered into interest rate swap agreements through our wholly-owned subsidiary, AGL Capital Corporation (AGL Capital), for the purpose of hedging the interest rate risk associated with our fixed and variable rate debt obligations. As of June 30, 2003, a notional principal amount of $175.0 million of these agreements effectively converts the interest expense associated with a portion of our Senior Notes and Trust Preferred Securities from fixed rates to variable rates based on an interest rate equal to the London Interbank Offered Rate (LIBOR), plus a spread determined at the swap date. As of June 30, 2003, our interest rate swaps are:

- $100.0 million principal amount of our 7.125% Senior Notes due 2011, we pay floating interest each January 14 and July 14 at six-month LIBOR plus 3.4%. For the three and six months ended June 30, 2003, the effective variable interest rate was 4.7%. These interest rate swaps expire January 14, 2011, unless terminated earlier.
- $75.0 million principal amount of our 8.0% Trust Preferred Securities due 2041, we pay floating interest rates each February 15, May 15, August 15 and November 15 at three-month LIBOR plus 1.315%. The effective interest rate for the three months ended June 30, 2003 was 2.6% and for the six months ended June 30, 2003 was 2.7%. These interest rate swaps expire May 15, 2041, unless terminated earlier.

These interest rate swaps have been designated as fair value hedges as defined by SFAS 133, which allows us to designate derivatives that hedge a recognized asset's or liability's exposure to changes in their fair value. We recognize the gain or loss on fair value hedges in earnings in the period of change together with the offsetting loss or gain on the hedged item attributable to the risk being hedged. The effect of that accounting is to reflect in earnings only that portion of the hedge that is not effective in achieving offsetting changes in fair value.

Our interest rate swaps meet the conditions required to assume no ineffectiveness under SFAS 133, and therefore, we have accounted for them using the "shortcut" method prescribed for fair value hedges by SFAS 133. Accordingly, we adjust the carrying value of each interest rate swap to its fair value each quarter, with an offsetting and equal adjustment to the carrying value of the debt securities whose fair value is being hedged. Consequently, our earnings are not affected negatively or positively with changes in fair value of the interest rate swaps each quarter. The aggregate fair value of these interest rate swaps at June 30, 2003 was $9.0 million and at December 31, 2002 was $6.1 million.

Derivative Instruments

We are exposed to risks associated with changes in the market price of natural gas. Through Sequent Energy Management, LP, (Sequent) we use derivative financial instruments to reduce our exposure to the risk of changes in the prices of natural gas as discussed below. Additionally, SouthStar manages a portion of its commodity price risks through hedging activities using derivative financial instruments and physical commodity contracts. The fair value of these derivative financial instruments reflects the estimated amounts that we would receive or pay to terminate or close the contracts at the reporting date, taking into account the current unrealized gains or losses on open contracts. We use external market quotes and indices to value substantially all of the financial instruments we utilize.

Under our risk management policy, we attempt to mitigate substantially all of our commodity price risk associated with Sequent's storage gas portfolio to lock in the economic margin at the time we enter into gas purchase transactions for our storage gas. We purchase gas for storage when the difference in the current market price we pay to buy gas plus the cost to store the gas is less than the market price we could receive in the future, resulting in a positive net profit margin. We use contracts to sell gas at that future price to substantially lock-in the profit margin we will ultimately realize when the stored gas is actually sold. These contracts meet the definition of a derivative under SFAS 133. The purchase, storage and sale of natural gas is accounted for differently than the derivatives we use to mitigate the commodity price risk associated with our storage portfolio. The difference in accounting can result in volatility in our reported net income, even though the economic margin is essentially unchanged from when the transactions were consummated. We do not currently use hedge accounting under SFAS 133 to account for this activity.

Gas that we purchase and inject into storage is accounted for at the lower of average cost or market as inventory in our condensed consolidated balance sheet, and is no longer marked to market following our implementation of the accounting guidance in EITF 02-03, which is discussed in greater detail later in this note. Under EITF 02-03 we would recognize a loss in any period when the market price for gas is lower than our carrying amount for our purchased gas inventory. Costs to store the gas are recognized in the period the costs are incurred. We recognize revenues and cost of gas sold in our condensed statements of consolidated income in the period we sell gas and it is delivered out of the storage facility. The derivatives we use to mitigate commodity price risk and to substantially lock in the margin upon sale of storage gas are accounted for at fair value and marked to market each period, with changes in fair value recognized as gains or losses in the period of change. This difference in accounting, the accrual basis for our storage gas inventory versus mark to market accounting for the derivatives used to mitigate commodity price risk, can result in volatility in our reported net income. Over time, gains or losses on the sale of storage gas inventory will be offset by losses or gains on the derivatives, resulting in our realization of the economic profit margin we expected when we entered into the transactions. This accounting difference causes Sequent's earnings on its storage gas positions to be affected by natural gas price changes, even though the economic profits remain essentially unchanged.

Commodity-related activities of our wholesale services segment, which includes Sequent, are monitored by our Risk Management Committee, which is charged with the review and enforcement of our risk management policy. Our risk management policy limits our risk management activities to hedging against price volatility to protect profit margins. Our policy explicitly prohibits the use of speculative trading. We use the following derivative financial instruments and physical transactions to manage such risks:

- forward contracts;
- futures contracts;
- options contracts;
- price and basis swaps; and
- storage and transportation capacity transactions.

Our risk management policy limits the use of these derivative financial instruments and physical transactions to hedge only those price risks associated with:

- pre-existing or anticipated physical natural gas sales;
- pre-existing or anticipated physical natural gas purchases; and
- system use and storage

During 2002, our wholesale services segment accounted for transactions in connection with energy marketing and risk management activities under the fair value, or mark-to-market method of accounting, in accordance with SFAS 133 and with Emerging Issues Task Force (EITF) Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities" (EITF 98-10). Under these methods, we recorded energy commodity contracts, including both physical transactions and financial instruments, at fair value, and reflected unrealized gains and/or losses in earnings in the period of change.

Effective January 1, 2003, we adopted EITF Issue No. 02-03 "Accounting for Contracts Involved in Energy Trading and Risk Management Activities" (EITF 02-03). EITF 02-03 rescinded the provisions of EITF 98-10 and reached two general conclusions:

- contracts that do not meet the definition of a derivative under SFAS 133 should not be marked to fair market value; and
- revenues should be shown in the income statement net of costs associated with trading activities, whether or not the trades are physically settled

We recorded the following as a result of our adoption of EITF 02-03:

- adjusted the carrying value of our non-derivative trading instruments (principally storage capacity contracts) to zero and now account for them using the accrual method of accounting;
- adjusted the value of our natural gas inventories used in our wholesale services segment to the lower of average cost or market, which were previously recorded at fair value. This resulted in a cumulative effect of a change in accounting principle in our condensed consolidated income statement of $12.6 million ($7.8 million net of taxes), that resulted in a decrease of $12.6 million to our energy marketing and risk management assets and a decrease to accumulated deferred income taxes of $4.8 million in our condensed consolidated balance sheets, and
- began reporting our trading activity on a net basis (revenues net of associated costs) effective July 1, 2002, and applied guidance from EITF 02-03 to all prior periods resulting in costs totaling approximately $435.9 million for the three months ended June 30, 2002 and $676.8 million for the six months ended June 30, 2002 being reclassified as a component of our revenues. This reclassification had no impact on our previously reported net income or shareholders' equity

Our derivative financial instruments have a weighted average maturity of one to three years, except for our interest rate swaps discussed earlier. Our derivative financial instruments for the three months ended June 30, 2003 and six months ended June 30, 2003 represented purchases (long) of 179.8 billion cubic feet and 411.3 billion cubic feet and sales (short) 200.5 billion cubic feet and 382.4 billion cubic feet.

We recorded unrealized losses of $3.6 million for the three months ended June 30, 2003 and unrealized gains of $1.1 million for the three months ended June 30, 2002 as a result of our energy marketing and risk management activities. Excluding the cumulative effect of a change in accounting principle, our unrealized gains during the six months ended June 30, 2003 were $6.0 million and we recorded unrealized losses of $1.0 million for the six months ended June 30, 2002.

The following table includes the fair values and average values of Sequent's energy marketing and risk management assets and liabilities at June 30, 2003. We based the average values on a monthly average for the three months ended and the six months ended June 30, 2003.

	Asset			Liability		
	Average Values		Value at June 30,	Average Values		Value at June 30,
In millions	Three-Months	Six-Months	2003	Three-Months	Six-Months	2003
Natural gas contracts	$16.5	$15.2	$11.6	$15.7	$17.8	$11.4

Concentration of Credit Risk

Concentration of credit risk occurs at AGLC, where costs for distribution operations are charged out and collected from both Georgia Public Service Commission (GPSC) Certificated Marketers (Marketers) selling retail natural gas in Georgia and poolers. For the six months ended June 30, 2003, the four largest Marketers based on customer count, one of which is our partially owned affiliate, accounted for approximately 55.1% of the Company's and 61.5% of distribution operations' operating margin.

Several factors are designed to mitigate our risks from the increased concentration of credit that has resulted from deregulation. The provisions of AGLC's tariff allow AGLC to obtain credit support in an amount equal to a minimum of two times a Marketer's highest month's estimated bill from AGLC. In addition, AGLC bills intrastate delivery service to the Marketers in advance rather than in arrears. We accept credit support in the form of cash deposits, letters of credit/surety bonds from acceptable issuers and corporate guarantees from investment grade entities. Our risk management committee reviews the adequacy of credit support coverage, credit rating profiles of credit support providers and payment status of each Marketer on a monthly basis. We believe that adequate policies and procedures have been put in place to properly quantify, manage and report on AGLC's credit risk exposure to Marketers.

Sequent, which provides services to Marketers, utility and industrial customers, also has a concentration of credit risk measured by 60-day receivable exposure. By this measure, Sequent's top 20 counterparties represent approximately 76% of our total exposure of $242 million. All of Sequent's counterparties are assigned internal ratings determined from the counterparty's external ratings with Standard & Poor's and Moody's. The internal rating is multiplied by the counterparty's credit exposure with Sequent and divided by our total counterparty credit exposure. As of June 30, 2003, Sequent's counterparties or the counterparty's guarantor have a weighted average Standard & Poor's equivalent credit rating of BBB.

2. Regulatory Assets and Liabilities

We have recorded regulatory assets and liabilities in our condensed consolidated balance sheets in accordance with SFAS "Accounting for the Effects of Certain Types of Regulation," excluding regulatory assets of approximately $1.0 million at Virginia Natural Gas (VNG), which are subject to reduction to the extent that VNG's return on pro-forma equity exceeds 10% as included in VNG's weather normalization adjustment program order. These regulatory assets are recoverable either through a rate rider or through base rates specifically authorized by a state commission. Our regulatory assets and liabilities, and associated liabilities for our unrecovered pipeline replacement program costs and unrecovered environmental response costs are summarized in the table below:

In millions	As of June 30, 2003	As of December 31, 2002
Regulatory assets		
Unrecovered pipeline replacement program costs	$455.3	$514.3
Unrecovered environmental response costs	179.1	195.1
Unrecovered postretirement benefit costs	10.8	10.9
Unrecovered seasonal rates	-	9.3
Deferred purchased gas adjustment	0.1	7.6
Other	0.7	2.7
Total	$646.0	$739.9
Regulatory liabilities		
Unamortized investment tax credit	$19.5	$20.2
Deferred purchased gas adjustment	15.5	18.0
Regulatory tax liability	13.1	13.5
Deferred seasonal rates	8.7	-
Other	1.0	1.0
Total regulatory liabilities	57.8	52.7
Associated liabilities		
Pipeline replacement program costs	431.6	494.0
Environmental response costs	85.9	105.0
Total associated liabilities	517.5	599.0
Total regulatory and associated liabilities	$575.3	$651.7

Pipeline Replacement

Atlanta Gas Light Company (AGLC) recorded a long-term liability of $364.5 million as of June 30, 2003 and $444.0 million as of December 31, 2002, which represent engineering estimates for remaining capital expenditure costs in the pipeline replacement program. The pipeline replacement program represents an approved settlement between AGLC and the GPSC that detailed a 10-year replacement of 2,300 miles of cast iron and bare steel pipe. AGLC recovers the costs through a combination of a straight fixed variable rate design, which spreads AGLC's delivery service revenue evenly throughout the year, and a pipeline replacement revenue rider. As of June 30, 2003, AGLC had recorded a current liability of $67.1 million representing expected pipeline replacement program expenditures for the next 12 months.

Environmental Matters

Before natural gas was widely available in the Southeast AGLC or its predecessor companies manufactured gas from coal and other fuels. Those manufacturing facilities were known as manufactured gas plants (MGPs), which AGLC ceased operating in the 1950's. AGLC identified 13 sites in Georgia and Florida where AGLC or its predecessors operated MGPs. In connection with these operations, AGLC is aware of the presence of coal tar and certain other by-products of the gas manufacturing process at or near some of these former sites. Based on investigations to date, AGLC believes that some cleanup is likely at most of these sites. AGLC has active environmental remediation or monitoring programs in effect at 11 sites in Georgia. There is no active remediation or monitoring program at two sites in Georgia.

As of June 30, 2003, our MGP remediation program was approximately 67% complete. Where the soil remediation is required at our Georgia sites, the work is targeted to be complete by January 2005. Two of the three sites in Florida are currently in the preliminary investigation or engineering design phase.

AGLC has historically reported estimates of future remediation costs for MGPs based on probabilistic models of potential costs. As cleanup options and plans mature and cleanup contracts are entered into, AGLC is increasingly able to provide conventional engineering estimates of the likely costs of many elements of its MGP program. These estimates contain various engineering uncertainties, and AGLC continuously attempts to refine and update these engineering estimates. In addition, AGLC continues to review technologies available for the cleanup of AGLC's two largest sites, Savannah and Augusta, which, if proven, could have the effect of reducing AGLC's total future expenditures.

Our last engineering estimate was as of March 31, 2003. This estimate projected costs associated with AGLC's engineering estimates and in-place contracts to be $85.2 million. For those remaining elements of the MGP program where AGLC is unable to perform engineering cost estimates at the current state of investigation, there remains considerable variability in the estimates for future remediation costs. For these elements, the estimates for the remaining cost of future actions at the MGP sites range from $7.5 million to $28.2 million. AGLC cannot estimate any single number within this range as a better estimate of its likely future costs. As a result, AGLC accrued the lower end of the range, or $7.5 million for these remaining elements in our environmental response costs. Finally, AGLC has estimates of certain other costs related to administering the MGP program. Through January 2005, AGLC estimates those costs to be $2.6 million; at this time AGLC generally cannot estimate expenses beyond this period.

As of June 30, 2003 and December 31, 2002, AGLC's environmental response cost liability is comprised of:

	As of:		
	June 30, 2003	December 31, 2002	Change
Projected engineering estimates and in-place contracts	$85.2	$109.2	($24.0)
Estimated future remediation costs	7.5	9.3	(1.8)
Other expenses	2.6	1.3	1.3
Cash payments for clean-up expenditures	(9.4)	(14.8)	5.4
Accrued environmental response costs	$85.9	$105.0	($19.1)

The environmental response cost liability is included in a corresponding regulatory asset. As of June 30, 2003, the regulatory asset was $179.1 million, which is a combination of the accrued environmental response costs and unrecovered cash expenditures. The liability does not include other potential expenses, such as unasserted property damage claims, personal injury or natural resource damage claims, unbudgeted legal expenses, or other costs for which AGLC may be held liable but with respect to which we cannot reasonably estimate the amount. The liability also does not include certain potential cost savings as described above.

AGLC has two ways of recovering investigation and cleanup costs. First, the GPSC has approved an environmental response cost recovery rider. It allows the recovery of costs of investigation, testing, cleanup and litigation. Because of that rider, these actual and projected future costs related to investigation and cleanup to be recovered from customers in future years are included in our regulatory asset. During the three and six months ended June 30, 2003, AGLC recovered $5.5 million and $11.1 million through its environmental response cost recovery rider. The second way AGLC can recover costs is by exercising the legal rights AGLC believes it has to recover a share of its costs from other potentially responsible parties, typically former owners or operators of the MGP sites. There were no material recoveries from potentially responsible parties during the six months ended June 30, 2003.

The significant years for spending for this program are 2003 and 2004. The environmental response cost recovery mechanism allows for recovery of expenditures over a five-year period subsequent to the period in which the expenditures were incurred. As of June 30, 2003, the MGP expenditures expected to be incurred over the next twelve months are reflected as a current liability of $48.4 million. In addition, AGLC expects to collect $23.8 million in revenues over the next twelve months under the environmental response cost recovery rider, which is reflected as a current asset.

3. Financing

Dollars in millions	Year(s) Due	June 30, 2003 Interest rate	June 30, 2003 Outstanding	December 31, 2002 Interest rate	December 31, 2002 Outstanding
Short-term debt:					
Commercial paper (1) (2)	2003	1.3%	$140.0	1.8%	$388.6
Current portion of long-term debt (2)	2003	5.9 -8.25	95.3	5.9	30.0
Sequent line of credit (3)	2004	2.0	7.5	-	-
Total short-term debt			**$242.8**		**$418.6**
Long-term debt - net of current portion:					
Medium-Term debt:					
Series A	2021	9.10	$30.0	9.10	$30.0
Series B	2004-2023	7.6 – 8.7	94.5	7.35 – 8.7	167.0
Series C	2005-2027	6.0 – 7.3	270.0	5.9 – 7.3	270.0
Senior Notes (2)	2011	7.125	300.0	7.125	300.0
AGL Capital Interest Rate Swaps (2)	2011	4.7	2.3	-	-
Total Medium-Term and Senior Notes			$696.8		$767.0
Trust Preferred Securities:					
AGL Capital Trust I	2037	8.17	$74.3	8.17	$74.3
AGL Capital Trust II	2041	8.0	147.3	8.0	146.8
AGL Capital Interest Rate Swaps	2041	2.6%	6.7	2.7%	6.1
Total Trust Preferred Securities			$228.3		$227.2
Total long-term debt			**$925.1**		**$994.2**
Total short-term and long-term debt			**$1,167.9**		**$1,412.8**

(1) The daily weighted average rate was 1.5% for the six months ended June 30, 2003 and 2.2% for the twelve months ended December 31, 2002.
(2) On July 2, 2003, we issued $225.0 million in Senior Notes. The proceeds were used to repay approximately $110.0 million of commercial paper and $65.3 million of long-term debt. Additionally, we entered into interest rate swaps of $100.0 million to effectively convert a portion of the fixed rate obligation on the $225.0 million Senior Notes to variable rate obligations. For more information see Note 8, "Subsequent Events."
(3) The daily weighted average rate was 1.8% for the six months ended June 30, 2003 and 2.3% for the twelve months ended December 31, 2002.

4. Commitments and Contingencies

The following table illustrates our expected future contractual cash obligations as of June 30, 2003.

	Payments Due before December 31,				
In millions	Total	2003	2004 & 2005	2006 & 2007	2008 & Thereafter
Long-term debt (1)	$1,014.8	$95.3	$75.5	$10.0	$834.0
Pipeline charges, storage capacity and gas supply (2) (3)	813.8	115.8	380.8	120.6	196.6
Pipeline replacement program costs (2)	431.7	26.7	162.0	162.0	81.0
Short-term debt	147.5	147.5	-	-	-
Operating leases	118.2	9.9	38.5	25.0	44.8
Environmental response costs (2)	85.4	23.7	47.8	1.4	12.5
Total	$2,611.4	$418.9	$704.6	$319.0	$1,168.9

(1) Includes $228.3 million of Trust Preferred Securities which are callable in 2006 and 2007.

(2) Distribution operations expenditures recoverable through rate rider mechanisms.

(3) Our total future contractual cash obligations were previously disclosed as $279.5 million, as of March 31, 2003, not including $399.3 million for pipeline charges and $184.9 million for future contractual cash obligations for the period of 2008 through 2019. Our total future contractual cash obligations were previously disclosed as $299.2 million, as of December 31, 2002, not including $441.9 million for pipeline charges and $184.9 million for future cash obligations for the period of 2008 through 2019

In January 2003, the FASB released FASB Interpretation No. 45, "Guarantors Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN 45). For many of the guarantees or indemnification agreements we issue, FIN 45 requires disclosure of the nature of the guarantee and the maximum potential amount of future payments that could be required of us as the guarantor. The table below illustrates our other expected commercial commitments that are outstanding as of June 30, 2003 and meet the disclosure criteria required by FIN 45.

	Amounts of Commitment Expiration per Period				
In millions	Total Amounts Committed	Less than 1 year	2-3 years	4-5 years	After 5 years
Lines of credit (1)	$515.0	$215.0	$300.0	$-	$-
Guarantees (2) (3)	321.8	321.8	-	-	-
Standby letters of credit, performance/ surety bonds	2.5	2.5	-	-	-
Total other commercial commitments	$839.3	$539.3	$300.0	$-	$-

(1) $500.0 million of these lines of credit represent our Credit Facility. $15.0 million of these lines of credit represent Sequent's unsecured line of credit.

(2) $314.8 million of these guarantees support credit exposures in Sequent's energy marketing and risk management business, and relate to amounts included in the energy marketing trade payable and the energy marketing and risk management liability included in the condensed consolidated balance sheets. In the event that Sequent defaults on any commitments under these guarantees, these amounts would become payable by us as parent.

(3) We provide guarantees on behalf of our affiliate, SouthStar Energy Services, LLC (SouthStar). We guarantee 70% of SouthStar's obligations to Southern Natural Gas Company and its affiliate South Georgia Natural Gas Company (together referred to as SONAT), under certain agreements between the parties up to a maximum of $7.0 million if SouthStar fails to make payment to SONAT. Under a second such guarantee we guarantee 70% of SouthStar's obligations to AGLC under certain agreements between the parties up to a maximum of $35 million which represents SouthStar's maximum obligation to AGLC under its tariff.

Caroline Street Campus

We have entered into an agreement to sell our 34-acre Caroline Street campus, where the majority of our Atlanta-based employees were located prior to our move to Ten Peachtree Place, our new corporate headquarters. This transaction, previously expected to close no later than December 31, 2003 is now expected to close before September 30, 2003. We anticipate that, upon closing, the estimated net gain will be approximately $10.0 million.

Litigation

We are involved in litigation arising in the normal course of business. We believe the ultimate resolution of such litigation will not have a material adverse effect on our consolidated financial position, results of operations and cash flows.

On July 1, 2003, the city of Augusta, Georgia served AGLC with a complaint that was filed in the Superior Court of Richmond County, Georgia against AGLC. Augusta's allegations include fraud and deceit and damages to realty. The allegations arise from negotiations between the city and AGLC regarding our environmental cleanup obligations connected with AGLC's former manufactured gas plant operations in Augusta. The city of Augusta seeks relief in the form of damages including an amount to be determined by a jury for the alleged fraud and deceit, together with attorney fees and punitive damages. We believe the claims asserted in this complaint are without merit, and we have remained in active settlement negotiations with the City. For more information about the manufactured gas plants and our environmental cleanup obligations, please see Item 1, Financial Statements, Note 2 "Regulatory Assets and Liabilities – Environmental Matters."

5. Related Party Transactions

We recognized revenue and had accounts receivable from SouthStar of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
In millions	2003	2002	2003	2002
Revenue	$41.1	$42.4	$89.7	$106.5
Accounts receivable	-	-	-	-

6. Investments in Equity Interests

We use the equity method to account for our equity interests where we hold a 20% to 50% voting interest, unless control [illegible] be exercised over the entity. Under the equity method, our ownership interest in the entity is reported as an investment within our condensed consolidated balance sheets. Additionally, our percentage ownership in our equity interest's earnings or losses is reported in our condensed statements of consolidated income under other income.

In January 2003, the FASB released FASB Interpretation No. 46, "Consolidation of Variable Interest Entities" (FIN 46). Companies with unconsolidated entities subject to FIN 46, or referred to as variable interest entities and issuing financial statements on or after January 31, 2003 are required to disclose the nature, purpose, size and activities of the variable interest entity as well as the company's maximum exposure to a loss as a result of its involvement with the variable interest entity. FIN 46 separates unconsolidated entities, including special purpose entities and investments in equity interests and partnerships, into two categories:

- entities for which the consolidation decision should be based on voting interests; and
- entities for which the consolidation decision should be based on variable interests and therefore are subject to FIN 46.

We have determined that our consolidation decision should be based on voting interests in reporting our investments in equity interests in SouthStar and US Propane, L.L.C. (US Propane).

Our investment in US Propane did not have a material effect on our financial position, results of operations and cash flows for the three and six months ended June 30, 2003 and 2002. Our investment in SouthStar, in which we currently hold a non-controlling 70% financial interest, had a material effect on our financial position and results of operations for the three and six months ended June 30, of 2003 and 2002. The unaudited amounts below represent 100% of the results of SouthStar. The results are not comparable with SouthStar's earnings or losses reported as other income in our condensed consolidated statements of income, since those amounts are reported based on our percentage ownership. SouthStar's net [illegible]ome from continuing operations and net income is equal as they do not incur income tax expenses.

SouthStar Energy Services, LLC
Summary Financials (at 100%)
(Unaudited)

In millions	As of: June 30, 2003	December 31, 2002
Balance Sheet:		
Current assets	$170.3	$169.0
Noncurrent assets	0.6	0.9
Current liabilities	55.7	83.6
Noncurrent liabilities	-	-

	Three Months Ended June 30, 2003	Three Months Ended June 30, 2002	Six Months Ended June 30, 2003	Six Months Ended June 30, 2002
Income Statement:				
Revenues	$131.3	$106.3	$416.6	$336.6
Gross margin	27.3	15.8	72.8	75.6
Operating income	9.8	0.1	39.6	37.5
Net income from continuing operations	12.9	0.5	39.8	37.9

7. Segment Information

Our business is organized into three operating segments:

- Distribution operations consists of AGLC, VNG and Chattanooga Gas Company (CGC).
- Wholesale services consists primarily of Sequent.
- Energy investments consists of SouthStar, AGL Networks, LLC (AGL Networks), US Propane and several other nonregulated, energy-related subsidiaries.

We treat our corporate segment as a nonoperating business segment, which includes AGL Resources Inc., AGL Services Company, nonregulated financing and captive insurance subsidiaries, and the effect of intercompany eliminations. We eliminated intersegment sales for the three and six months ended June 30, 2003 and 2002 from our condensed consolidated statements of income.

Management evaluates segment performance based on a non-GAAP measure of earnings before interest and taxes (EBIT), which includes the effects of corporate expense allocations. Items that we do not include in EBIT are financing costs, including interest and debt expense, income taxes and the cumulative effect of change in accounting principle, each of which we evaluate on a consolidated level. We believe EBIT is a useful measurement of our performance for you because it provides information that can be used to evaluate the effectiveness of our businesses from an operational perspective, exclusive of the costs to finance those activities and exclusive of income taxes, neither of which are directly relevant to the efficiency of those operations.

EBIT should not be considered an alternative to, or more meaningful an indicator of our operating performance than operating income or net income as determined in accordance with GAAP. In addition, our EBIT may not be comparable to a similarly titled measure of another company.

The reconciliations of our EBIT to operating income and net income are presented below for the three and six months ended June 30, 2003 and 2002:

	Three Months Ended June 30,		Six Months Ended June 30,	
In millions	2003	2002	2003	2002
Operating income	$40.9	$41.9	$142.4	$115.9
Other income	8.3	(1.7)	24.4	24.6
EBIT	49.2	40.2	166.8	140.5
Interest expense and preferred stock dividends	18.2	21.2	38.1	43.9
Earnings before income taxes	31.0	19.0	128.7	96.6
Income taxes	12.1	6.7	50.2	34.2
Income before cumulative effect of change in accounting principle	18.9	12.3	78.5	62.4
Cumulative effect of change in accounting principle	-	-	(7.8)	-
Net income	$18.9	$12.3	$70.7	$62.4

In millions	Distribution Operations		Wholesale Services		Energy Investments		Corporate (2)		Consolidated AGL Resources	
As of:	June 30, 2003	Dec. 31, 2002	June 30, 2003	Dec. 31, 2002	June 30, 2003	Dec. 31, 2002	June 30, 2003	Dec. 31, 2002	June 30, 2003	Dec. 31, 2002
Identifiable assets (1)	$3,124.7	$3,149.8	$443.3	$364.3	$87.9	$107.2	($110.3)	$45.9	$3,545.6	$3,667.2
Investments in equity interests	-	-	-	-	112.3	74.8	-	-	112.3	74.8
Total assets	$3,124.7	$3,149.8	$443.3	$364.3	$200.2	$182.0	($110.3)	$45.9	$3,657.9	$3,742.0

(1) Identifiable assets are those assets used in each segment's operations. Our corporate segment's assets consist primarily of intercompany eliminations, cash and cash equivalents and property, plant and equipment.
(2) Includes intercompany eliminations.

	Three months ended June 30,									
illions	Distribution Operations		Wholesale Services		Energy Investments		Corporate (2)		Consolidated AGL Resources	
	2003	2002	2003	2002	2003	2002	2003	2002	2003	2002
Operating revenues (1)	$181.7	$160.0	$4.1	$0.9	$0.7	$0.3	0.1	$-	$186.6	$161.2
Depreciation and amortization	20.2	20.6	-	-	0.1	-	2.4	1.9	22.7	22.5
Operating income	43.8	47.4	0.3	(2.4)	(2.0)	(1.7)	(1.2)	(1.4)	40.9	41.9
Interest income	-	0.1	-	-	-	-	-	-	-	0.1
Earnings in equity interests	-	-	-	-	8.6	(1.7)	-	-	8.6	(1.7)
Other income (loss)	0.2	0.1	-	-	-	0.1	(0.5)	(0.3)	(0.3)	(0.1)
Total other income (loss)	0.2	0.2	-	-	8.6	(1.6)	(0.5)	(0.3)	8.3	(1.7)
EBIT	44.0	47.6	0.3	(2.4)	6.6	(3.3)	(1.7)	(1.7)	49.2	40.2
Capital expenditures	30.6	30.2	1.2	0.2	1.9	3.4	7.2	6.5	40.9	40.3

	Six months ended June 30,									
In millions	Distribution Operations		Wholesale Services		Energy Investments		Corporate (2)		Consolidated AGL Resources	
	2003	2002	2003	2002	2003	2002	2003	2002	2003	2002
Operating revenues (1)	$502.3	$423.1	$32.6	$9.5	$4.1	$0.5	$0.1	$-	$539.1	$433.1
Depreciation and amortization	40.3	42.0	-	-	0.2	-	4.5	3.6	45.0	45.6
Operating income	124.4	118.6	21.0	3.5	(2.1)	(3.4)	(0.9)	(2.8)	142.4	115.9
Interest income	0.1	0.2	-	-	0.1	-	-	-	0.2	0.2
Earnings in equity interests	-	-	-	-	24.4	24.6	-	-	24.4	24.6
Other income (loss)	0.4	0.2	-	-	0.2	0.1	(0.8)	(0.5)	(0.2)	(0.2)
Total other income (loss)	0.5	0.4	-	-	24.7	24.7	(0.8)	(0.5)	24.4	24.6
EBIT	124.9	119.0	21.0	3.5	22.6	21.3	(1.7)	(3.3)	166.8	140.5
pital expenditures	56.2	63.7	1.4	1.5	5.7	12.6	13.9	9.6	77.2	87.4

(1) Intersegment revenues – We record our wholesale services segment's energy marketing and risk management revenues on a net basis. The following table provides detail of our wholesale services segments' total gross revenues and gross sales to our distribution operations segment:

In millions	Three months ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
Third-party gross revenues	$808.5	$411.9	$1,874.7	$636.6
Intersegment revenues	93.7	24.9	207.1	49.8
Total gross revenues	$902.2	$436.8	$2,081.8	$686.4

(2) Includes intercompany eliminations.

8. Subsequent Events

On July 2, 2003, AGL Capital issued $225.0 million in Senior Notes with a maturity date of April 15, 2013. The Senior Notes have an interest rate of 4.45% payable on April 15 and October 15 of each year, beginning October 15, 2003. Interest will accrue from July 2, 2003. On July 10, 2003, we exercised our option to redeem $65.3 million of Medium-Term notes at a call premium. These notes were scheduled to mature in 2013 and 2023 bearing various interest rates ranging from 7.5% to 8.25%. We used the net proceeds from the Senior Notes to repay these Medium-Term notes and approximately $110.0 million of short-term debt and for general corporate purposes.

Additionally, we entered into interest rate swaps of $100.0 million to effectively convert a portion of the fixed rate interest obligation on the $225.0 million in Senior Notes due 2013 to a variable rate obligation. We pay floating interest on the interest rate swaps on April 15 and October 15 at six month LIBOR plus 0.615%. These interest rate swaps expire April 15, 2013, unless terminated earlier, and have been designated as fair value hedges under SFAS 133.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Our reports, filings and other public announcements often include statements reflecting assumptions, expectations, projections, intentions or beliefs about future events. These statements, which may relate to such matters as future earnings, growth, supply and demand, costs, subsidiary performance, new technologies and strategic initiatives, are "forward-looking statements" within the meaning of the federal securities laws. These statements do not relate strictly to historical or current facts, and you can identify certain of these statements, but not necessarily all, by the use of the words "anticipate," "assume," "indicate," "estimate," "believe," "predict," "forecast," "rely," "expect," "continue," "grow" and other words of similar meaning. Although we believe that the expectations and assumptions reflected in these statements are reasonable in view of the information currently available, we cannot assure you that these expectations will prove to be correct. These forward-looking statements involve a number of risks and uncertainties. Actual results may differ materially from the results discussed in the forward-looking statements. Please reference our website at aglresources.com for current information. Our electronic filings with the Securities and Exchange Commission (SEC) are available at no cost on our website. In addition to the risks set forth in the prospectus supplement filed with the SEC on February 12, 2003 and incorporated herein by reference, the following are among the important factors that could cause actual results to differ materially from the forward-looking statements:

- changes in industrial, commercial and residential growth in our service territories
- changes in price, supply and demand for natural gas and related products
- impact of changes in state and federal legislation and regulation, including orders of various state public service commissions and of the Federal Energy Regulatory Commission (FERC) on the gas and electric industries and on us, including AGLC's performance-based rate plan (PBR)
- the ultimate impact of the Sarbanes-Oxley Act of 2002 and any future changes in accounting regulations or practices in general with respect to public companies, the energy industry or our operations specifically
- the enactment of new accounting standards by the Financial Accounting Standards Board (FASB) or the SEC that could impact the way we record revenues, assets and liabilities, which could lead to impacts on reported earnings or increases in liabilities, which in turn could affect our reported results of operations
- market changes due to Georgia's Natural Gas Consumers' Relief Act of 2002
- effects and uncertainties of deregulation and competition, particularly in markets where prices and providers historically have been regulated, unknown issues following deregulation such as the stability of Georgia Public Service Commission (GPSC) Certificated Marketers (Marketers) selling natural gas in Georgia and unknown risks related to nonregulated businesses, including risks related to energy marketing and risk management
- concentration of credit risk in Marketers and our wholesale services segment's counterparties
- excess high-speed network capacity, and demand for dark fiber in metro network areas
- market acceptance of new technologies and products, as well as the adoption of new networking standards
- our ability to negotiate new fiber optic contracts with telecommunications providers for the provision of AGL Networks' dark fiber services
- utility and energy industry consolidation
- performance of equity and bond markets and the impact on pension and post-retirement funding costs
- impact of acquisitions and divestitures
- direct or indirect effects on our business, financial condition or liquidity resulting from a change in our credit rating or the credit rating of our counterparties or competitors
- interest rate fluctuations, financial market conditions and general economic conditions
- uncertainties about environmental issues and the related impact of such issues
- impact of changes in weather upon the temperature-sensitive portions of our business
- impact of litigation
- impact of changes in prices on the margins achievable in the unregulated retail gas marketing business

Overview

We are an energy services holding company, headquartered in Atlanta, Georgia, whose principal business is the distribution of natural gas in Georgia, Virginia and Tennessee. We operate three utilities, which combined, serve approximately 1.8 million end-users, making us the largest gas utility in the southeastern United States, and the second-largest pure gas distribution utility in the United States. We are also involved in various non-utility businesses, including natural gas asset management and producer services; last-mile telecommunications infrastructure; retail gas marketing; and propane services. We manage our business in three operating segments: distribution operations, wholesale services and energy investments and one nonoperating segment: corporate.

We are focused on a business strategy centered around effective management of our gas distribution operations, optimization of returns on our assets, and selective growth of our portfolio of closely related, unregulated businesses with an emphasis on risk management and earnings visibility.

Highlights

- For the three months ended June 30, 2003, our net income was $18.9 million or $0.29 per diluted common share, an increase of $6.6 million or $0.07 per diluted common share for the same period last year.
- For the six months ended June 30, 2003, our net income was $70.7 million or $1.13 per diluted common share, an increase of $8.3 million or $0.02 per diluted common share for the same period last year. Our income before cumulative effect of change in accounting principle increased $16.1 million or $0.15 per diluted common share.
- On April 16, 2003, we increased our dividends from $0.27 to $0.28 per common share, or an indicated annual rate of $1.12 per common share. The new quarterly dividend was paid June 1, 2003, to our shareholders of record as of the close of business May 16, 2003.
- On June 5, 2003, our market price per share reached an all-time high of $26.98 per share an 11.0% increase from our year-end closing price.
- On June 16, 2003, we renewed until June 16, 2004 our $200.0 million 364-Day Credit Facility with a one year term-out option that was scheduled to expire on August 7, 2003.
- On July 2, 2003, AGL Capital Corporation issued $225 million in Senior Notes at an interest rate of 4.45%. We used the net proceeds to repay approximately $110.0 million of short-term debt and $65.3 million of long-term debt, as well as for general corporate purposes. Additionally we entered into interest rate swaps of $100.0 million to effectively convert a portion of the fixed-rate obligation on these Senior Notes to variable rate obligation at an effective interest rate at six month LIBOR plus 0.615%.

Results of Operations

Our management evaluates segment performance based on Earnings Before Interest and Taxes (EBIT), which includes the effects of corporate expense allocations. Items that are not included in EBIT are financing costs, including interest and debt expense, income taxes and the cumulative effect of changes in accounting principle. We evaluate each of these items on a consolidated level. We believe EBIT is a useful measurement of our performance for you because it provides information that can be used to evaluate the effectiveness of our businesses from an operational perspective, exclusive of the costs to finance those activities and exclusive of income taxes, neither of which are directly relevant to the efficiency of those operations.

You should not consider EBIT an alternative to, or a more meaningful indicator of our operating performance than operating income or net income as determined in accordance with accounting principles generally accepted in the United States of America (GAAP). In addition, our EBIT may not be comparable to a similarly titled measure of another company. The following is a reconciliation of our operating results to EBIT for the three and six months ended June 30, 2003 and 2002:

	Three Months Ended June 30,			Six Months Ended June 30,		
In millions	**2003**	**2002**	**Change**	**2003**	**2002**	**Change**
Operating income	$40.9	$41.9	($1.0)	$142.4	$115.9	$26.5
Other income	8.3	(1.7)	10.0	24.4	24.6	(0.2)
EBIT	49.2	40.2	9.0	166.8	140.5	26.3
Interest expense and dividends on preferred securities	18.2	21.2	3.0	38.1	43.9	5.8
Earnings before income taxes	31.0	19.0	12.0	128.7	96.6	32.1
Income taxes	12.1	6.7	(5.4)	50.2	34.2	(16.0)
Income before cumulative effect of change in accounting principle	18.9	12.3	6.6	78.5	62.4	16.1
Cumulative effect of change in accounting principle	-	-	-	(7.8)	-	(7.8)
Net income	$18.9	$12.3	$6.6	$70.7	$62.4	$8.3
Basic earnings per common share						
Income before cumulative effect of change in accounting principle	$0.30	$0.22	0.08	$1.27	$1.12	0.15
Cumulative effect of change in accounting principle	-	-	-	(0.13)	-	(0.13)
Basic	$0.30	$0.22	0.08	$1.14	$1.12	0.02
Diluted earnings per common share						
Income before cumulative effect of change in accounting principle	$0.29	$0.22	0.07	$1.26	$1.11	0.15
Cumulative effect of change in accounting principle	-	-	-	(0.13)	-	(0.13)
Diluted	$0.29	$0.22	0.07	$1.13	$1.11	0.02
Weighted-average number of common shares outstanding						
Basic	63.5	56.0	7.5	61.9	55.9	6.0
Diluted	64.2	56.5	7.7	62.4	56.2	6.2

As a result of our equity issuance on February 14, 2003, we experienced a dilution of our basic and diluted earnings per share of approximately $0.03 for the three months ended June 30, 2003 and $0.09 per share for the six months ended June 30, 2003. This was primarily due to our issuance of an additional 6.4 million shares partially offset by a decrease of $0.3 million in interest expense, net of income taxes, for the three months ended June 30, 2003 and $0.4 million, net of income taxes, for the six months ended June 30, 2003.

Results of Operations

Below are the results of our segments operations as measured by EBIT, for the three and six months ended June 30, 2003 and 2002:

In millions	Three Months Ended June 30, 2003	Three Months Ended June 30, 2002	Change	Six Months Ended June 30, 2003	Six Months Ended June 30, 2002	Change
Distribution operations	$44.0	$47.6	($3.6)	$124.9	$119.0	$5.9
Wholesale services	0.3	(2.4)	2.7	21.0	3.5	17.5
Energy investments	6.6	(3.3)	9.9	22.6	21.3	1.3
Corporate	(1.7)	(1.7)	-	(1.7)	(3.3)	1.6
AGL Resources' consolidated EBIT	$49.2	$40.2	$9.0	$166.8	$140.5	$26.3

Income Taxes

Dollars in millions	Three Months Ended June 30, 2003	Three Months Ended June 30, 2002	Change	Six Months Ended June 30, 2003	Six Months Ended June 30, 2002	Change
Earnings before income taxes	$31.0	$19.0	$12.0	$128.7	$96.6	$32.1
Income tax expense	12.1	6.7	(5.4)	50.2	34.2	(16.0)
Effective tax rate	39.0%	35.3%	(3.7%)	39.0%	35.4%	(3.6%)

The increase in our income tax expense of $5.4 million for the three months ended June 30, 2003 as compared to the three months ended June 30, 2002 was due primarily to the increase in earnings before income taxes of $12.0 million and the increase in our effective tax rate from 35.3% in 2002 to 39.0% in 2003. The increase in the effective tax rate was primarily due to higher projected state income taxes.

The increase in income tax expense of $16.0 million for the six months ended June 30, 2003 as compared to the six months ended June 30, 2002 was due primarily to the increase in earnings before income taxes of $32.1 million and an increase in our effective tax rate from 35.4% in 2002 to 39.0% in 2003. The increase in the effective tax rate was primarily due to higher projected state income taxes.

Interest Expense and Preferred Securities Dividends

Dollars in millions	Three Months Ended June 30, 2003	Three Months Ended June 30, 2002	Change	Six Months Ended June 30, 2003	Six Months Ended June 30, 2002	Change
Interest expense and dividends on preferred securities	$18.2	$21.2	$3.0	$38.1	$43.9	$5.8
Average debt outstanding (1)	$1,113.8	$1,373.5	$259.7	$1,204.6	$1,412.1	$207.5
Average rate	6.5%	6.2%	(0.3%)	6.3%	6.2%	(0.1%)

(1) Includes Trust Preferred Securities

The decrease in our interest expense of $3.0 million and $5.8 million for the three and six months ended June 30, 2003 as compared to the same periods last year was a result of lower average debt balances due to the proceeds generated from the equity offering and lower working capital needs partially offset by higher average rates.

Distribution Operations

Our distribution operations segment includes the results of operations and financial condition of our three natural gas local distribution companies: Atlanta Gas Light Company (AGLC), Virginia Natural Gas (VNG) and Chattanooga Gas Company (CGC).

- **AGLC** is a natural gas local distribution utility with distribution systems and related facilities serving 237 cities throughout Georgia, including Atlanta, Athens, Augusta, Brunswick, Macon, Rome, Savannah and Valdosta. AGLC has approximately 6.0 billion cubic feet or Bcf, of liquefied natural gas (LNG) storage capacity in three LNG plants to supplement the supply of natural gas during peak usage periods.

- **VNG** is a natural gas local distribution utility with distribution systems and related facilities serving 8 cities in the Hampton Roads region of southeastern Virginia. VNG owns and operates approximately 155 miles of a separate high-pressure pipeline that provides delivery of gas to customers under firm transportation agreements within the state of Virginia. VNG also has approximately 5.0 million gallons of propane storage capacity in its two propane facilities to supplement the supply of natural gas during peak usage periods.

- **CGC** is a natural gas local distribution utility with distribution systems and related facilities serving 12 cities and surrounding areas, including the Chattanooga and Cleveland areas of Tennessee. CGC also has approximately 1.2 Bcf of LNG storage capacity in its LNG plant.

The Georgia Public Service Commission (GPSC) regulates AGLC; the Virginia State Corporation Commission (VSCC) regulates VNG; and the Tennessee Regulatory Authority (TRA) regulates CGC, with respect to rates, maintenance of accounting records and various other service and safety matters.

The results of operations of our distribution operations segment are as follows:

	Three Months Ended June 30,			**Six Months Ended June 30,**		
In millions	**2003**	**2002**	**Change**	**2003**	**2002**	**Change**
Operating revenues	$181.7	$160.0	$21.7	$502.3	$423.1	$79.2
Cost of sales	45.4	24.2	(21.2)	193.5	121.2	(72.3)
Operating margin	136.3	135.8	0.5	308.8	301.9	6.9
Operation and maintenance expenses	65.8	61.6	(4.2)	131.0	128.8	(2.2)
Depreciation and amortization	20.2	20.6	0.4	40.3	42.0	1.7
Taxes other than income	6.5	6.2	(0.3)	13.1	12.5	(0.6)
Total operating expenses	92.5	88.4	(4.1)	184.4	183.3	(1.1)
Operating income	43.8	47.4	(3.6)	124.4	118.6	5.8
Other income	0.2	0.2	-	0.5	0.4	0.1
EBIT	$44.0	$47.6	($3.6)	$124.9	$119.0	$5.9

Metrics			**% Change**			**% Change**
Average end-use Customers (in thousands)	1,852	1,840	0.7%	1,857	1,841	0.9%
Throughput (millions of dekatherms)	50	52	(3.8%)	176	163	8.0%
Heating degree days:						
Georgia	132	136	(2.9%)	1,685	1,589	6.0%
Virginia	307	234	31.2%	2,269	1,802	25.9%
Tennessee	117	160	(26.9%)	1,942	1,720	12.9%

The decrease in EBIT of $3.6 million for the three months ended June 30, 2003 as compared to the three months ended June 30, 2002 was due to:

- an increase in operating margin of $0.5 million primarily as a result of :
  - a $1.5 million increase in VNG's margin caused by higher usage per degree day and increased customer growth.
  - a $0.4 million decrease in AGLC's margin primarily due to:
    - a $1.8 million increase in pipeline replacement program rider revenue
    - a $0.8 million decrease from the performance based rate settlement with the GPSC that was effective beginning May 1, 2002
    - a $0.8 million decrease due to lower carrying charges on natural gas stored underground on behalf of AGLC's Marketers, and
    - $0.6 million decrease in other service revenues.
  - a $0.5 million decrease in CGC's margin due primarily to a decrease in industrial volumes, and
- an increase in operation and maintenance expenses of $4.1 million due to higher service company overhead and increased bad debt expenses resulting from higher revenue.

The increase in EBIT of $5.9 million for six months ended June 30, 2003 as compared to the six months ended June 30, 2002 was due to:

- an increase in operating margin of $7.0 million which was primarily a result of:
  - a $10.4 million increase in VNG's operating margin caused primarily by the effects of WNA and warmer than normal weather in 2002, higher usage per degree day and an increase in customer growth.
  - a $2.9 million decrease in AGLC's operating margin caused primarily by:
    - a $3.3 million decrease from the performance based rate settlement with the GPSC
    - a $2.2 million decrease due to lower carrying charges on natural gas stored underground on behalf of Marketers.
    - a $1.6 million decrease in services fees and other revenues; these decreases were offset by
    - a $3.2 million increase in pipeline replacement program rider revenue and
    - a $1.0 million increase resulting from customer growth.
  - a $0.5 million decrease in CGC operating margin caused primarily by a decrease in industrial volumes.
- higher operation and maintenance expenses of $2.2 million due to higher service company overhead and increased bad debt expenses, and
- a decrease in depreciation expense of $1.6 million due to a change in AGLC's depreciation rates resulting from the performance based rate settlement with the GPSC.

Wholesale Services

Our wholesale services segment includes the results of operations and financial condition of Sequent Energy Management, LP (Sequent), our asset optimization, gas supply services, and wholesale marketing and risk management subsidiary. Our asset optimization activities focus on capturing the value from idle or underutilized natural gas assets, typically by participating in transactions that balance the needs of varying markets and time horizons. These assets include rights to pipeline capacity, underground storage, and natural gas peaking services and facilities. Sequent also aggregates gas from other marketers and producers and sells it to third parties. In addition, Sequent bundles this commodity with transportation and storage service and redelivers short-term and long-term transported commodity.

Although Sequent is a nonregulated business, under varying agreements, Sequent acts as asset manager for our regulated utilities. In its capacity as asset manager, Sequent captures value from idle or underutilized assets of our utilities by arbitraging price differentials across different locations and over time. We worked with each of our state regulatory commissions to clarify Sequent's role as asset manager for our regulated utilities, and have reached the following agreements:

- In November 2000, the VSCC approved an asset management agreement, which provides for a sharing of profits between Sequent and VNG's customers.
- In June 2003, CGC's tariff was amended effective January 1, 2003 to require all net margin earned from CGC assets to be shared equally with CGC ratepayers.
- Various Georgia statutes require Sequent, as asset manager for AGLC, to share 90% of its earnings from capacity release transactions with Georgia's Universal Service Fund (USF). Sequent is also required by a December 2002 GPSC order to equally share net margin earned by Sequent, for transactions involving AGLC assets, other than capacity release, with Georgia's USF.

During 2002, our wholesale services segment accounted for transactions in connection with energy marketing in accordance with SFAS No. 133 "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133) and accounted for risk management activities in accordance with Emerging Issues Task Force (EITF) Issue No. 98-10 "Accounting for Contracts Involved in Energy Trading and Risk Management Activities" (EITF 98-10). Under these methods, we recorded energy commodity contracts, including both physical transactions and financial instruments at fair value, with unrealized gains and/or losses reflected in our earnings in the period of change.

Effective January 1, 2003, we adopted EITF Issue No. 02-03, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities" (EITF 02-03). EITF 02-03 rescinded EITF 98-10 and reached two general conclusions:

- contracts that do not meet the definition of a derivative under SFAS 133 should not be marked to fair market value, and
- revenues should be shown in the income statement net of costs associated with trading activities, whether or not the trades are physically settled.

We recorded the following as a result of our adoption of EITF 02-03 we:

- adjusted the carrying value of our non-derivative trading instruments (principally our storage capacity contracts) to zero and now account for them using the accrual method of accounting;
- adjusted the value of our natural gas inventories used in our wholesale services segment to the lower of average cost or market, which were previously recorded at fair value. This resulted in a cumulative effect of change in accounting principle in our condensed consolidated statements of income for the three months ended March 31, 2003 of $12.6 million ($7.8 million net of taxes), that resulted in a decrease of $12.6 million to energy marketing and risk management assets and a decrease in accumulated deferred income taxes of $4.8 million in our accompanying condensed consolidated balance sheets, and
- began reporting our trading activity on a net basis (revenues net of costs) effective July 1, 2002, as a result of consensus one of EITF 02-03. We applied this guidance to all periods, resulting in costs totaling approximately $435.9 million for the three months ended June 30, 2002 and $676.8 million for the six months ended June 30, 2002 being reclassified as a component of revenues. This reclassification had no impact on our previously reported net income or shareholders' equity

The results of operations for our wholesale services segment are as follows:

	Three Months Ended June 30,			Six Months Ended June 30,		
In millions	**2003**	**2002**	**Change**	**2003**	**2002**	**Change**
Operating revenues	$4.1	$0.9	$3.2	$32.6	$9.5	$23.1
Cost of sales	-	-	-	0.1	-	(0.1)
Operating margin	4.1	0.9	3.2	32.5	9.5	23.0
Operation and maintenance expenses	3.7	3.2	(0.5)	11.3	5.8	(5.5)
Depreciation and amortization	-	-	-	-	-	-
Taxes other than income	0.1	0.1	-	0.2	0.2	-
Total operating expenses	3.8	3.3	(0.5)	11.5	6.0	(5.5)
Operating income	0.3	(2.4)	2.7	21.0	3.5	17.5
Other income	-	-	-	-	-	-
EBIT	$0.3	($2.4)	$2.7	$21.0	$3.5	$17.5

Metrics			**% Change**			**% Change**
Physical sales volumes (billions of cubic feet/day)	1.71	1.35	26.6%	1.83	1.22	50.0%
NYMEX (1) average settled price (2)	$5.40	$3.40	58.8%	$6.00	$2.86	109.8%

(1) New York Mercantile Exchange, Inc.
(2) The average settlement of the April through June and January through June futures contracts for each year, respectively.

The increase in EBIT of $2.7 million for the three months ended June 30, 2003 as compared to the three months ended June 30, 2002 was primarily due to a 27% increase in volume sold as a result of Sequent's efforts to gain additional new business with local distribution companies, electric utilities and large industrial customers as well as an increase in the purchase of direct gas supply from producers. This was offset by an increase in operation and maintenance expenses resulting from the increased staffing levels required to support the growth in our business.

Sequent recorded unrealized losses of $3.6 million during the three months ended June 30, 2003, and unrealized gains of $1.1 million during the three months ended June 30, 2002 related to derivative instruments as a result of energy marketing and risk management activities.

The increase in EBIT of $17.5 million for the six months ended June 30, 2003 as compared to the six months ended June 30, 2002 was primarily due to the items mentioned above, along with optimization of various transportation and storage assets that Sequent utilized, mainly in the first quarter when natural gas prices were highly volatile. Also, during the three months ended March 31, 2003, Sequent sold substantially all of its entire inventory, which was previously recorded on a mark-to-market basis under the now rescinded EITF 98-10. This resulted in $12.6 million in realized income, offset by sharing with our affiliated local distribution companies, for transactions that were recorded on a mark-to-market basis in prior periods.

Sequent's physical sales volumes for the six months ended June 30, 2003 increased 50% as compared to the same period last year. This increase is attributable to Sequent's successful efforts to gain additional new business as detailed above. Additionally, a number of market factors, including colder temperatures in market areas served by Sequent, coupled with reduced amounts of gas in storage as the winter progressed, resulted in increased volatility in Sequent's markets. The volatility in natural gas market prices as compared to the first quarter of 2003 has decreased by over 50%. Although actual prices continue to trade in a higher range as compared to the average price of the last several years, the volatility in the second quarter has declined to approximately the 2002 calendar year average.

Sequent recorded unrealized gains of $6.0 million, excluding the cumulative effect of change in accounting principle during the six months ended June 30, 2003, and unrealized losses of $1.0 million during the six months ended June 30, 2002 related to derivative instruments as a result of energy marketing and risk management activities.

We recorded the derivative instruments that Sequent utilized in its energy marketing and risk management activities on a mark-to-market basis in both the three and six months ended June 30, of 2003 and 2002. We also recorded energy-trading contracts as defined under EITF 98-10 on a mark-to-market basis for the six months ended June 30, 2002. The tables below illustrate the change in the net fair value of the derivative instruments and energy-trading contracts during the three and six months ended June 30, 2003 and 2002, as well as provides details of the net fair value of contracts outstanding as of June 30, 2003. Sequent's storage positions are affected by price sensitivity in the NYMEX average price.

	Three Months Ended June 30,		Six Months Ended June 30,	
In millions	2003	2002	2003	2002
Net fair value of contracts outstanding at beginning of period	$3.8	$0.6	$6.8	$2.9
Cumulative effect of change in accounting principle	-	-	(12.6)	-
Net fair value of contracts outstanding at beginning of period, as adjusted	3.8	0.6	(5.8)	2.9
Contracts realized or otherwise settled during period	(1.3)	0.2	(4.0)	(2.3)
Net fair value of net claims against counterparties	-	-	-	-
Change in net fair value of contracts gains (losses)	(2.3)	1.1	10.0	1.3
Net fair value of new contracts entered into during period	-	-	-	-
Change in fair value attributed to changes in valuation techniques and assumptions	-	-	-	-
Net fair value of contracts outstanding at end of period	$0.2	$1.9	$0.2	$1.9

In millions	Net Fair Value of Contracts at Period End				
Source of net fair value	Maturity less than 1 year	Maturity 1-3 years	Maturity 4-5 years	Maturity in excess of 5 years	Total net fair value
Prices actively quoted	($1.0)	$1.2	$-	$-	$0.2
Prices provided by other external sources	-	-	-	-	-
Prices based on models and other valuation methods	-	-	-	-	-

The "prices actively quoted" category represents Sequent's positions in natural gas, which are valued using a combination of NYMEX futures prices and basis spreads. The basis spreads represent the cost to transport the commodity from a NYMEX delivery point such as Henry Hub to the contract delivery point. Our basis spreads are based on broker quotes obtained either directly or through electronic trading platforms.

Energy Investments

Our energy investments segment includes our investments in SouthStar Energy Services, LLC (SouthStar) and US Propane L.L.C. (US Propane) as well as the results of operations and financial condition of AGL Networks LLC (AGL Networks).

- **SouthStar** is a joint venture formed in 1998 by subsidiaries of AGL Resources, Piedmont Natural Gas Company (Piedmont) and Dynegy Inc. (Dynegy) to market natural gas and related services to retail customers, principally in Georgia. SouthStar is the largest retail marketer of natural gas in Georgia with a market share of 38% and operates under the trade name Georgia Natural Gas. Initially, our subsidiary owned a 50% interest, Piedmont's subsidiary owned a 30% interest and Dynegy's subsidiary owned the remaining 20% in SouthStar. On January 24, 2003, we announced that our wholly owned subsidiary, Georgia Natural Gas Company, reached an agreement to purchase Dynegy's 20% ownership interest of SouthStar. The transaction closed March 11, 2003 and for accounting purposes had an effective date of February 18, 2003. Upon closing, our subsidiary owned a non-controlling 70% financial interest in SouthStar and Piedmont's subsidiary owned the remaining 30%. Although we own 70% of SouthStar, we do not have a controlling interest as matters of significance require the unanimous vote of Piedmont's representative and our representative to the governing board of SouthStar.

  SouthStar's operating policy contains a provision for the disproportionate sharing of earnings between Piedmont and us when SouthStar's annual earnings before taxes are above an annual threshold. The annual threshold is calculated each year based on a cumulative and annual 17% return on contributed capital. SouthStar's operating policy requires that earnings above the threshold be allocated at various percentages based on actual margin generated in the four defined service areas of the operating policy, and distributed annually to each owner as a mandatory distribution. Disproportionate sharing is only applicable to our original 50% financial interest in SouthStar.

  We estimate that SouthStar's earnings before taxes for the twelve months ended December 31, 2002, 2001 and 2000 were above the threshold. We estimate our increased portion of SouthStar's equity earnings, previously attributed to Piedmont, for the twelve months ended December 31, 2002 to be $2.3 million to $4.4 million pre-tax. This reflects our estimate that our actual earnings from SouthStar were at a level of approximately 55.7% to 60.7% of total earnings, rather than our equity ownership of 50% of total earnings. We estimate our increased portion of equity earnings from SouthStar for the twelve months ending December 31, 2001 and 2000 to be up to $2.6 million pre-tax. Because the partners have not historically agreed on the annual earnings threshold, no disproportionate distributions have occurred to date.

  Our estimated increased portion of equity earnings for the twelve months ended December 31, 2002 is based on our interpretation of SouthStar's operating policy. Because the estimate is still subject to change we will not record our increased portion of equity earnings until our increased portion of equity earnings is received. The earnings test is based on SouthStar's fiscal year ending December 31. Therefore, we have estimated the disproportionate sharing only through December 31, 2002, however, based on current estimates we expect that disproportionate sharing on our original 50% interest in SouthStar will occur again in 2003.

- **US Propane** is a joint venture formed in 2000 by subsidiaries of AGL Resources, Atmos Energy Corporation, Piedmont Natural Gas Company and TECO Energy, Inc. We own 22.36% of the limited partnership interest in US Propane. US Propane owns all of the general partnership interests, directly or indirectly, and approximately 25% of the limited partnership interests in Heritage, a publicly traded marketer of propane. Heritage is the fourth largest retail marketer of propane in the United States, delivering approximately 350 million gallons per year to approximately 650,000 customers in 29 states.

- **AGL Networks**, our wholly owned subsidiary, is a carrier-neutral provider of last-mile infrastructure and dark fiber solutions to a variety of customers in the Atlanta, Georgia and Phoenix, Arizona metropolitan areas. Its customers include local, regional and national telecommunication companies, wireless service providers, educational institutions and other commercial entities. AGL Networks typically provides conduit and dark fiber to its customers under long-term lease arrangements with terms that vary from three to twenty years. In addition to conduit and dark fiber leasing, AGL Networks also provides turnkey telecommunications network construction services.

The results of operations for our energy investments segment are as follows:

In millions	Three Months Ended June 30, 2003	2002	Change	Six Months Ended June 30, 2003	2002	Change
Operating revenues	$0.7	$0.3	$0.4	$4.1	$0.5	$3.6
Cost of sales	-	0.2	0.2	0.4	0.3	(0.1)
Operating margin	0.7	0.1	0.6	3.7	0.2	3.5
Operation and maintenance expenses	2.5	1.8	(0.7)	5.3	3.5	(1.8)
Depreciation and amortization	0.1	-	(0.1)	0.2	-	(0.2)
Taxes other than income	0.1	-	(0.1)	0.3	0.1	(0.2)
Total operating expenses	2.7	1.8	(0.9)	5.8	3.6	(2.2)
Operating income	(2.0)	(1.7)	(0.3)	(2.1)	(3.4)	1.3
Other income	8.6	(1.6)	10.2	24.7	24.7	-
EBIT	$6.6	($3.3)	$9.9	$22.6	$21.3	$1.3

Metrics:	**Six Months Ended June 30, 2003**	**2002**	**% Change**
SouthStar			
Average Customers	572,991	577,262	(0.7%)
Volumes (millions of dekatherms)	38.6	39.6	(2.5%)
AGL Networks			
% Dark fiber miles leased - Atlanta	8.8%	-	-
% Dark fiber miles leased – Phoenix	3.3%	-	-

The increase in EBIT of $9.9 million for the three months ended June 30, 2003 as compared to the three months ended June 30, 2002 was due to:

- a $10.3 million increase in other income from SouthStar, primarily as a result of increased volume on a per customer basis and an increase in our ownership from 50% to 70%, this was offset by
- a $1.0 million decrease in EBIT from AGL Networks, resulting from increased operating expenses due to additional personnel necessary to support business growth, partially offset by an increase in monthly recurring contract revenues.

The increase in EBIT of $1.3 million for the six months ended June 30, 2003 as compared to the six months ended June 30, 2002 was due to:

- a $0.6 million increase in EBIT from AGL Networks that reflects an increase in monthly recurring contract revenues of $1.2 million and $2.3 million from a sales-type lease which were partially offset by increased operating expenses of $2.5 million due to additional personnel necessary to support business growth.
- a $1.0 million increase in other income from US Propane due to colder than normal weather, offset by
- a $1.1 million decrease in other income from SouthStar, primarily as a result of lower margins from higher gas prices in the first quarter of 2003 and a $7.0 million inventory adjustment recorded in the first quarter of 2002, offset by increased volume on a per customer basis in the second quarter of 2003, lower bad debt and customer care expense and an increase from our ownership from 50% to 70% effective in mid-February 2003.

Corporate

Our corporate segment includes the results of operations and financial condition of our nonoperating business units, including AGL Services Company and AGL Capital Corporation (AGL Capital). AGL Services Company is a service company established in accordance with the Public Utility Holding Company Act of 1935, as amended (PUHCA). AGL Capital provides for our ongoing financing needs through a commercial paper program, the issuance of various debt and hybrid securities, and other financing arrangements. We allocate AGL Services Company's and AGL Capital's operating expenses and interest costs to our operating segments in accordance with PUHCA and state regulations. Our corporate segment also includes intercompany eliminations for transactions between our operating business segments.

The results of operations for our corporate segment are as follows:

	Three Months Ended June 30,			**Six Months Ended June 30,**		
In millions	**2003**	**2002**	**Change**	**2003**	**2002**	**Change**
Operating revenues	$0.1	$-	$0.1	$0.1	$-	$0.1
Cost of sales	-	-	-	-	-	-
Operating margin	0.1	-	0.1	0.1	-	0.1
Operation and maintenance expenses	(2.1)	(1.4)	0.7	(5.5)	(2.7)	2.8
Depreciation and amortization	2.4	1.9	(0.5)	4.5	3.6	(0.9)
Taxes other than income	1.0	0.9	(0.1)	2.0	1.9	(0.1)
Total operating expenses	1.3	1.4	0.1	1.0	2.8	1.8
Operating income	(1.2)	(1.4)	0.2	(0.9)	(2.8)	1.9
Other income	(0.5)	(0.3)	(0.2)	(0.8)	(0.5)	(0.3)
EBIT	($1.7)	($1.7)	$-	($1.7)	($3.3)	$1.6

The increase in EBIT of $1.6 million for the six months ended June 30, 2003 as compared to the six months ended June 30, 2002 was due to prior year accrued expenses that were not allocated.

Liquidity and Capital Resources

We rely upon operating cash flow along with borrowings under our commercial paper program, which are backed by our supporting credit agreement, or our Credit Facility, for our short-term liquidity and capital resource requirements. Our availability of borrowings under the Credit Facility is subject to conditions specified within the Credit Facility, which we currently meet. These conditions include our compliance with the financial covenants required by the Credit Facility and the continued accuracy of representations and warranties contained in the agreements.

We believe our operating cash flow, borrowings from the commercial paper program and other credit availability will be sufficient to meet our working capital needs. We may seek additional financing through debt or equity offerings in the private or public markets at any time. Although we currently have no borrowings outstanding under our Credit Facility, unused availability is limited by our total debt to capital ratios, as represented in the following table.

In millions	As of June 30, 2003	December 31, 2002
Unused availability under the Credit Facility	$500.0	$244.1
Cash and cash equivalents	3.4	8.4
Total cash and available liquidity under Credit Facility	$503.4	$252.5

As a result of our equity offering and increased operating cash flow, our total cash and available liquidity under our Credit Facility at June 30, 2003 increased $250.9 million from December 31, 2002. As of June 30, 2003 Sequent's unsecured line of credit had approximately $7.5 million available for the posting of margin deposits.

Our cash from operations, credit capacity and the amount of our unused borrowing capacity may change in the future due to a number of factors, some of which we cannot control. These factors include:

- The seasonal nature of the natural gas business and our short-term borrowing requirements that typically peak during colder months;
- Increased gas supplies required to meet our customers' needs during cold weather;
- Regulatory changes;
- Changes in the wholesale prices and our customers' demand for our products and services;
- Margin requirements resulting from significant increases or decreases in our commodity prices; and
- Operational risks.

Cash Flows

Our cash and cash equivalents were $3.3 million as of June 30, 2003, a decrease of $5.1 million from December 31, 2002. As of June 30, 2002, our cash and cash equivalents were $4.3 million, a decrease of $3.0 million from December 31, 2001. Our principal sources and uses of cash during the six months ended June 30, 2003 and six months ended June 30, 2002 are summarized below.

Six Months Ended June 30, 2003:

Sources

- We generated $204.7 million in cash, primarily through cash from our operations, plus decreases in our receivables and increases in our payables. This was offset by increases in our inventories
- We received $136.7 million from our equity offering
- We received $10.0 million from our sale of treasury stock
- We received $7.0 million from our investments in equity interests
- We received $6.6 million from our other investing and financing activities

Uses

- We paid $241.1 million (net of borrowings) to reduce our outstanding short-term debt from the commercial paper program
- We invested $77.2 million in property, plant and equipment
- We invested $20.0 million in our investments in equity interests
- We paid $31.8 million in cash dividends on our common stock

Six Months Ended June 30, 2002:

Sources

- We generated $201.3 million in cash, primarily through cash from our operations, plus increases in payables and decreases in inventories. This was offset by increases in receivables
- We received $9.9 million from our sale of treasury stock
- We received $4.1 million from our investments in equity interests
- We received $0.7 million from our other investing and financing activities

Uses

- We invested $87.4 million in property, plant and equipment
- We paid $60.2 million (net of borrowings) to reduce our outstanding short-term debt from the commercial paper program
- We paid $45.0 million in scheduled payments on our Medium-Term notes
- We paid $26.4 million in cash dividends on our common stock

Financing

Ratios Our Credit Facility financial covenants and PUHCA require us to maintain a ratio of total debt to total capitalization of no greater than 70.0%. As of June 30, 2003, we were in compliance with this leverage ratio requirement. The components of our capital structure, as of the dates indicated, are summarized in the following table.

Dollars in millions	June 30, 2003		As of: December 31, 2002		June 30, 2002	
Short-term debt	$147.5	7.1%	$388.6	18.3%	$324.5	15.3%
Current portion of long-term debt	95.3	4.6	30.0	1.4	48.0	2.2
Senior and Medium Term notes (1)	696.8	33.8	767.0	36.1	797.0	37.5
Trust Preferred Securities (2)	228.3	11.1	227.2	10.7	220.5	10.4
Total debt	1,167.9	56.6	1,412.8	66.5	1,390.0	65.4
Common equity	895.9	43.4	710.1	33.5	734.8	34.6
Total capitalization	$2,063.8	100.0%	$2,122.9	100.0%	$2,124.8	100.0%

(1) Net of interest rate swaps of $2.3 million as of June 30, 2003.
(2) Net of interest rate swaps of $6.7 million, $6.1 million, and ($0.1) million respectively.

Short-term Debt. Our short-term debt is comprised of borrowings under our commercial paper program and Sequent's line of credit. The commercial paper program is supported by our Credit Facility which consists of:

- a $200 million 364-day Credit Facility with a one year term-out option that was originally scheduled to expire on August 7, 2003 but was renewed until June 16, 2004.
- a $300 million 3 year Credit Facility that terminates on August 7, 2005.

As of July 25, 2003, we had no outstanding borrowings under the Credit Facility. The following table provides details on AGL Capital's commercial paper program.

In millions, except interest rates	Three Months Ended June 30, 2003	2002	Six Months Ended June 30, 2003	2002
Average outstanding balance	$97.1	$299.6	$183.4	$316.5
Weighted-average interest rate	1.4%	2.3%	1.5%	2.4%

Sequent has a $15.0 million unsecured line of credit, which is used solely for the posting of margin deposits and is unconditionally guaranteed by AGL Resources. This line of credit was renewed on July 3, 2003, expires on July 2, 2004, and bears interest at the federal funds effective rate plus 0.5%. As of June 30, 2003, the line of credit had an outstanding balance of $7.5 million. The following table provides details on Sequent's line of credit.

In millions, except interest rates	Three Months Ended June 30, 2003	2002	Six Months Ended June 30, 2003	2002
Average outstanding balance	$1.8	$3.8	$2.8	$2.7
Weighted-average interest rate	1.8%	2.3%	1.8%	2.3%

Long-term Debt. We have $30.0 million in scheduled Medium-Term note payments due in October 2003, with an interest rate of 5.90%. We expect to utilize the availability of working capital and liquidity under the commercial paper program to fund these scheduled payments. During the six months ended June 30, 2003, we did not issue any long-term debt.

On April 1, 2003, we exercised our option to call at par two Medium-Term notes totaling $7.2 million before their scheduled maturity dates. A note of $5.0 million bearing interest of 7.4% was scheduled to mature in March 2013, and a note of $2.2 million bearing interest of 7.5% was scheduled to mature in March 2014. We redeemed these notes using proceeds from the issuance of commercial paper.

On July 2, 2003, we issued $225.0 million in Senior Notes due April 15, 2013. The Senior Notes have an interest rate of 4.45% payable on April 15 and October 15 of each year, beginning October 15, 2003. Interest will accrue from July 2, 2003. We used the net proceeds from the Senior Notes to repay $65.3 million of our Medium-Term notes, discussed below, and approximately $110.0 million of short-term debt and for general corporate purposes.

On July 2, 2003, we also entered into interest rate swaps of $100.0 million to effectively convert $100 million of the fixed rate obligation on the $225.0 million in Senior Notes due 2013 issued on July 2, 2003, to variable rate obligations. We pay floating interest on the interest rate swaps on April 15 and October 15 at six month LIBOR plus 0.615%. These interest rate swaps expire April 15, 2013, unless terminated earlier and we have designated the swaps as fair value hedges under SFAS 133.

On July 10, 2003, we exercised our option to redeem $65.3 million of Medium-Term notes at a call premium. These notes were scheduled to mature in 2013 and 2023 bearing various interest rates ranging from 7.5% to 8.25%.

Interest Rate Swaps. For a discussion of our interest rate swaps, see Item 1, Financial Statements, Note 1 *"Significant Accounting Policies"* which is incorporated herein by reference.

Available Capacity Under Shelf Registration. We have a shelf registration statement registered with the SEC for up to $750 million of various capital securities. Including the effect of the recent equity and Senior Note offerings, as of July 25, 2003, we had approximately $383 million remaining capacity under this shelf registration statement.

Credit Rating. Credit ratings impact our ability to obtain short-term and long-term financing and the cost of such financing. In determining our credit ratings, the rating agencies consider a number of factors. Quantitative factors that appear to be given significant weight include, among other things:

- earnings before interest, taxes, depreciation and amortization
- operating cash flow
- total debt outstanding
- total equity outstanding
- pension liabilities and funding status
- other commitments
- fixed charges such as interest expense, rent or lease payments
- payments to preferred stockholders
- liquidity needs and availability
- potential legislation on deregulation
- total debt to total capitalization ratios
- various ratios calculated from these factors

Qualitative factors appear to include, among other things, stability of regulation in each jurisdiction, risks and controls inherent with wholesale services, predictability of cash flows, business strategy, management, industry position and contingencies.

Our credit ratings may be subject to revision or withdrawal at any time by the assigning rating organization and you should evaluate each rating independently of any other rating. We cannot assure you that a rating will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances so warrant. For the six months ended June 30, 2003 no fundamental adverse shift occurred in our business or ratings profile.

The following table presents, as of July 25, 2003, the credit ratings on our unsecured debt issues from the three major rating agencies. The ratings are all investment-grade status and the outlooks for all credit ratings are stable.

Type of facility	Moody's	S&P	Fitch
Commercial paper	P-2	A-2	F-2
Medium-Term notes	A3	A-	A
Senior notes	Baa1	BBB+	A-
Trust Preferred Securities	Baa2	BBB	BBB+

Our debt instruments and other financial obligations include provisions that if not complied with, could require early payment, additional collateral support or similar actions. Our most important default events include:

- A maximum leverage ratio.
- Minimum net worth.
- Insolvency events and nonpayment of scheduled principal or interest payments.
- Acceleration of other financial obligations.
- Change of control provisions.

We do not have any trigger events in our debt instruments that are tied to changes in our specified credit ratings or our stock price and have not entered into any transaction that requires us to issue equity based on credit rating or other trigger events. We are currently in compliance with all existing debt provisions.

Sequent has certain trade and/or credit contracts that have explicit credit rating trigger events in case of a credit rating downgrade. These rating triggers typically would give counterparties the right to suspend or terminate credit if our credit ratings were downgraded to non-investment grade status. Under such circumstances, we would need to post collateral to continue transacting business with some of our counterparties. Posting collateral would have a negative effect on our liquidity. If such collateral was not posted, our ability to continue transacting business with these counterparties would be impaired. At June 30, 2003, such agreements between Sequent and its counterparties totaled $12 million. We believe the existing cash and available liquidity under our Credit Facility is adequate to fund these potential liquidity requirements.

Capital Requirements

Environmental Matters

We expect the manufactured gas plants remediation program to be complete with respect to the significant cleanup by January 2005. The significant years for spending for this program are 2003 and 2004. The remaining liability for the environmental response cost program as of June 30, 2003 is estimated to be $85.9 million.

For a discussion on our contractual cash obligations and other commercial commitments, see Item 1, Financial Statements, Note 4 *"Commitments and Contingencies"* which is incorporated herein by reference.

Critical Accounting Policies

The selection and application of critical accounting policies is an important process that has progressed as our business activities have evolved and as a result of new accounting pronouncements. Accounting rules generally do not involve a selection among alternatives, but rather involve an implementation and interpretation of existing rules and the use of judgment as to the specific set of circumstances existing in our business. Each of the critical accounting policies involves complex situations requiring a high degree of judgment either in the application and interpretation of existing literature or in the development of estimates that impact our financial statements.

Regulatory Accounting

We account for transactions within our distribution operations segment according to the provisions of SFAS No. 71 "Accounting for the Effects of Certain Types of Regulation." Applying this accounting policy allows us to defer expenses and income in the consolidated balance sheets as regulatory assets and liabilities when it is probable that those expenses and income will be allowed in the rate setting process in a period different from the period in which they would have been reflected in the statements of consolidated income of an unregulated company. We then recognize these deferred regulatory assets and liabilities in our statement of consolidated income in the period in which we reflect the same amounts in rates.

If any portion of our distribution operations segment ceased to continue to meet the criteria for application of regulatory accounting treatment for all or part of its operations, we would eliminate the regulatory assets and liabilities related to those portions ceasing to meet such criteria from our consolidated balance sheet and include them in our statement of consolidated income for the period in which the discontinuance of regulatory accounting treatment occurred.

Pipeline Replacement

AGLC has recorded a long-term liability of $364.5 million as of June 30, 2003 and $444.0 million as of December 31, 2002, that represent engineering estimates for remaining capital expenditure costs in the pipeline replacement program (PRP). The PRP represents an approved settlement between AGLC and the staff of the GPSC that details a 10-year replacement of 2,300 miles of cast iron and bare steel pipe. We recover the costs through a combination of a straight fixed variable rate that spreads AGLC's delivery service revenue evenly throughout the year and a pipeline replacement revenue rider. As of June 30, 2003, AGLC had recorded a current liability of $67.1 million representing the expected expenditures of the program for the next 12 months.

Environmental Matters

AGLC historically reported estimates of future remediation costs based on probabilistic models of potential costs. As we continue to develop cleanup options and plans and we continue to enter cleanup contracts, AGLC is increasingly able to provide conventional engineering estimates of the likely costs of many elements of its manufactured gas plant (MGP) program. These estimates contain various engineering uncertainties, and AGLC continuously attempts to refine and update these engineering estimates.

In addition, AGLC continues to review technologies available for the cleanup of AGLC's two largest sites, Savannah and Augusta, which, if proven, could have the effect of reducing AGLC's total future expenditures. Our latest estimate, as of March 31, 2003, projects costs associated with AGLC's engineering estimates and in-place contracts to be $85.2 million. For those remaining elements of the MGP program where AGLC still cannot perform engineering cost estimates, there remains considerable variability in available future cost estimates. For these elements, the remaining cost of future actions at the MGP sites is $7.5 million to $28.2 million. AGLC cannot estimate any single number within this range as a better estimate of its likely future costs. As a result, AGLC accrued the lower end of the range of $7.5 million for these remaining elements in our environmental response costs. Finally, AGLC has estimates of certain other costs paid directly by AGLC related to administering the MGP program. Through January 2005, AGLC estimates those costs to be $2.6 million; at this time AGLC generally cannot estimate expenses beyond this period. Consequently, as of June 30, 2003 and December 31, 2002, AGLC's environmental response cost liability is comprised of:

	As of: June 30, 2003	December 31, 2002	Change
Projected engineering estimates and in-place contracts	$85.2	$109.2	($24.0)
Estimated future remediation costs	7.5	9.3	(1.8)
Other expenses	2.6	1.3	1.3
Cash payments for clean-up expenditures	(9.4)	(14.8)	5.4
Accrued environmental response costs	$85.9	$105.0	($19.1)

The environmental response cost liability is included in a corresponding regulatory asset. As of June 30, 2003, the regulatory asset was $179.1 million, which is a combination of the accrued environmental response costs and unrecovered cash expenditures. AGLC's estimate does not include other potential expenses, such as unasserted property damage, personal injury or natural resource damage claims, unbudgeted legal expenses, or other costs for which AGLC may be held liable but with respect to which the amount cannot be reasonably forecast. AGLC's estimate also does not include certain potential cost savings as described above.

Revenue Recognition

Distribution Operations

VNG and CGC employ rate structures that include volumetric rate designs that allow recovery of costs through gas usage. VNG and CGC recognize revenues from sales of natural gas and transportation services in the same period in which they deliver the related volumes to customers. VNG and CGC bill and recognize sales revenues from residential and certain commercial and industrial customers on the basis of scheduled meter readings. In addition, VNG and CGC record revenues for estimated deliveries of gas, not yet billed to these customers, from the meter reading date to the end of the accounting period. We include these revenues in our consolidated balance sheets as unbilled revenue. Included in the rates charged by VNG and CGC is a weather normalization adjustment factor, which offsets the impact of unusually cold or warm weather on our operating margin. Beginning in November 2002, VNG's rates include a two-year experimental weather normalization adjustment program. For certain commercial and industrial customers and all wholesale customers, VNG and CGC recognize revenues based upon actual deliveries during the accounting period.

Wholesale Services

We record our wholesale services segment's revenues when physical sales of natural gas and natural gas storage volumes are delivered to the specified delivery point based on contracted or market prices. We reflect revenues from commodities sold as part of wholesale services' trading and derivative activities that are not designated as hedges net of the cost of these sales. We record derivative transactions at their fair value.

Our wholesale services segment accounts for derivative instruments under SFAS 133, which requires us to reflect all derivatives, as defined therein in our balance sheet at their fair value as risk management activities. The market prices or fair values used in determining the value of these contracts are Sequent's best estimates utilizing information such as commodity exchange prices, over-the-counter quotes, volatility and time value, counterparty credit and the potential impact on market prices of liquidating positions in an orderly manner over a reasonable period of time under current market conditions. When the portfolio market value changes, primarily due to newly originated transactions and the effect of price changes, our wholesale services segment recognizes the change of derivative instruments as a gain or loss in the period of change. We recognize cash inflows and outflows associated with settlement of these risk management activities in operating cash flows, and we report any receivables and payables resulting from these activities resulting from these settlements separately from risk management activities in the balance sheet as energy marketing receivables and payables. We adopted the net presentation provisions of the June 2002 consensus for EITF 02-03 on July 1, 2002. As required under the consensus, we present gains and losses from energy-trading activities on a net basis. This results in costs totaling approximately $435.9 million for the three months ended June 30, 2002 and $676.8 million for the six months ended June 30, 2002 being reclassified as a component of our revenues. This reclassification had no impact on our previously reported net income or shareholders' equity.

During 2002, our wholesale services segment accounted for transactions in connection with energy marketing and risk management activities under the fair value or mark-to-market methods of accounting, in accordance with SFAS 133 and EITF 98-10. Under these methods, we recorded energy commodity contracts, including both physical transactions and financial instruments at fair value, with unrealized gains and/or losses reflected in earnings in the period of change. Effective January 1, 2003, we adopted the final provisions of EITF 02-03, which rescinded EITF 98-10. Prior to EITF 02-03, wholesales services accounted for non-derivative energy instruments, such as contracts for storage capacity and physical natural gas inventory, at their fair value under EITF 98-10.

As a result of the adoption, wholesale services adjusted the fair value of its non-derivative trading instruments to zero and now accounts for them under the accrual method of accounting. In addition, wholesale services' natural gas inventories are now recorded at the lower of cost or market. The cumulative effect of the change in accounting principle resulted in a $12.6 million pre-tax reduction to income before cumulative effect of change in accounting principle ($7.8 million net of taxes) and a decrease of $12.6 million to energy marketing and risk management assets and a $4.8 million decrease to accumulated deferred income taxes in our accompanying condensed consolidated balance sheets.

Energy Investments

SouthStar

SouthStar recognizes revenues from sales of natural gas and transportation services in the same period in which they deliver the related volumes to customers. SouthStar bills and recognizes sales revenues from residential and certain commercial and industrial customers on the basis of scheduled meter readings. In addition, SouthStar records revenues for estimated deliveries of gas, not yet billed to these customers, from the meter reading date to the end of the accounting period. For certain commercial and industrial customers and all wholesale customers, SouthStar recognizes revenues based upon actual deliveries during the accounting period.

AGL Networks

We recognize revenues attributable to leases of dark fiber pursuant to indefeasible rights-of-use (IRU) agreements as services are provided. Dark fiber IRU agreements generally require the customer to make a down payment upon execution of the agreement; however, in some cases AGL Networks receives up to the entire lease payment at the inception of the lease and recognizes revenue ratably over the lease term. As a result, we record deferred revenue in our condensed consolidated balance sheet. In addition, AGL Networks recognizes sales revenues upon the execution of certain sales-type agreements for dark fiber when the agreements provide for the transfer of the legal title to dark fiber to the customer at the end of the agreement's term. This sales-type accounting treatment is in accordance with EITF Issue No. 00-11 "Lessors' Evaluation of Whether Leases of Certain Integral Equipment Meet the Ownership Transfer Requirements of FASB Statement No. 13 *Accounting for Leases*, for leases of Real Estate" and FAS No. 66 "Accounting for Sales of Real Estate", which provides that such transactions meet the criteria for sales-type lease accounting if the agreement obligates the lessor to deliver documents that convey ownership of the underlying asset to the lessee by the end of the lease term.

AGL Networks is obligated, under the dark fiber IRUs, to maintain the network in efficient working order and in accordance with industry standards. Customers contract with AGL Networks to provide maintenance services for the network. AGL Networks recognizes this maintenance revenue as services are provided.

AGL Networks also engages in construction projects on behalf of customers. Projects are considered substantially complete upon customer acceptance and the revenue and associated expenses are recorded at that time.

Accounting for Contingencies

Our accounting policies for contingencies cover a variety of business activities, including contingencies for potentially uncollectible receivables, rate matters, and legal and environmental exposures. We accrue for these contingencies when our assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered, and an amount can be reasonably estimated in accordance with SFAS No. 5 "Accounting for Contingencies." We base our estimates for these liabilities on currently available facts and our estimates of the ultimate outcome or resolution of the liability in the future. Actual results may differ from estimates, and estimates can be, and often are, revised either negatively or positively, depending upon actual outcomes or expectations based on the facts surrounding each potential exposure.

Accounting for Pension Benefits

We have a defined benefit pension plan for the benefit of substantially all full-time employees and qualified retirees. We use several statistical and other factors that attempt to anticipate future events and to calculate the expense and liability related to the plan. These factors include assumptions about the discount rate, expected return on plan assets and rate of future compensation increases as determined by us. In addition, our actuarial consultants use subjective factors such as withdrawal and mortality rates to estimate the projected benefit obligation. The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates, or longer or shorter life spans of participants. These differences may result in a significant impact on the amount of pension expense recorded in future periods.

The combination of poor equity market performance and historically low corporate bond rates has created a divergence in the estimated value of the pension liability and the actual value of the pension assets. These conditions resulted in an increase in our unfunded accumulated benefit obligation (ABO) and future pension expenses and could impact our future contributions. The primary factors that drive the value of our unfunded ABO are the discount rate and the market value of plan assets as of year end.

As of December 31, 2002, we recorded an additional minimum pension liability of $79.9 million, which resulted in an after tax charge to other comprehensive income of $48.5 million. To the extent that our future expenses and contributions increase as a result of the additional minimum pension liability, we believe that such increases are recoverable in all or in part, under our future rate proceedings or mechanisms.

Equity market performance and corporate bond rates have a significant effect on our reported unfunded ABO as the primary assumptions that drive the value of our unfunded ABO are the discount rate and expected return on plan assets. A one-percentage point increase or decrease in the assumed discount rate could have a negative or positive impact to the ABO of approximately $40.0 million. Additionally, a one-percentage point increase or decrease in the assumed expected return on assets would decrease or increase our pension expense by approximately $2.5 million.

As of June 30, 2003, the market value of the pension assets was $225.3 million as compared to a market value of $207.8 million as of December 31, 2002. The net increase of $17.5 million from December 31, 2002 to June 30, 2003 results from our contribution of $6.5 million on February 14, 2003 and our actual return on plan assets of $20.9 million less benefits paid of $9.9 million. Our $6.5 million contribution is expected to reduce pension expense approximately $0.5 million for the twelve months ended December 31, 2003.

The actual return on plan assets of $20.9 million as compared to the expected return on plan assets could have an impact on our benefit obligation as of December 31, 2003 and our pension expense for 2004. We are unable to determine how this actual return on plan assets will affect future benefit obligation and pension expense; as actuarial assumptions and differences between actual and expected returns on plan assets are determined at the time we complete our actuarial evaluation as of December 31, 2003. Our actual returns may also be positively or negatively impacted as a result of future performance in the equity and bond markets.

Regulatory and Legislative Overview

Federal Activity

The Pipeline Safety Improvement Act of 2002, enacted on December 17, 2002, addresses improved safety and integrity of the industry's large diameter transmission pipeline systems. This Act requires that the Office of Pipeline Safety (OPS) establish new regulations on the inspection of transmission pipelines by December 2003. If OPS fails to do that, then there are identified requirements within the Act which will require us to inspect all of our transmission lines in high consequence areas over the next 10 years and to take appropriate remedial action. OPS issued a Notice of Proposed Rulemaking that was open for comments through the end of April 2003. OPS rules are scheduled to be issued no later than December 17, 2003. Based on initial estimates, the bill will require our three utility subsidiaries to inspect and take remedial action on approximately 350 miles of large diameter pipelines with an estimated cost over that 10 year period of $22 million. We believe that since the efforts that require these expenditures are federally mandated, the costs are recoverable in state regulatory proceedings.

State Activity

None of the three state jurisdictions in which we operate passed any legislation that would significantly impact our businesses during their most recent legislative sessions.

Since 1998, there have been a number of federal and state proceedings regarding the role of AGLC and its administration and assignment of interstate assets to Marketers pursuant to the provisions of the Natural Gas Competition and Deregulation Act of Georgia. As part of those proceedings, AGLC has entered into a stipulation with the GPSC staff, industrial customers, the Governor's Office of Consumer Affairs and all but one of the Marketers on its systems, regarding the assignment of its interstate capacity assets. A hearing to approve the settlement has been conducted and by a vote of 5-0 on July 24, 2003 the GPSC approved the stipulation. Under the terms of that authorization, AGLC is authorized to:

- offer two additional sales services pursuant to GPSC approved tariffs, and
- acquire and continue managing the interstate transportation and storage contracts which underlie the sales services provided to the Marketers on its distribution system under GPSC approved tariffs.

Item 3. Quantitative and Qualitative Disclosure About Market Risk

We are exposed to risks associated with commodity prices, interest rates and credit. Commodity price risk is defined as potential loss that we may incur as a result of changes in the fair value of a particular instrument or commodity. Interest rate risk results from our portfolio of debt and equity instruments that we issue to provide financing and liquidity for our business. Credit risk results from the extension of credit throughout all aspects of our business, but is particularly concentrated in our distribution operations segment at AGLC and in our wholesale services segment.

Our risk management committee (RMC) is responsible for the overall establishment of risk management policies and the monitoring of compliance with and adherence to the terms within these policies, including the delegation of approval and authorization levels. Our RMC consists of senior executives who monitor commodity price risk positions, corporate exposures, credit exposures and overall results of our risk management activities. Our RMC is chaired by our chief risk officer, who is responsible for ensuring that appropriate reporting mechanisms exist for the RMC to perform its monitoring functions.

Commodity Price Risk

Wholesale Services. Sequent is exposed to certain commodity price risks inherent in the natural gas industry or inherent in transactions entered in the normal course of business. In executing risk management strategies to mitigate these risks, our wholesale services segment routinely utilizes various types of financial and other instruments. These instruments include a variety of exchange-traded and over-the-counter energy contracts, such as forward contracts, futures contracts, option contracts and financial swap agreements.

The financial and other derivative instruments that we use require payments to or receipt of payments from counterparties based on the differential between a fixed and variable price for the commodity, options and other contractual arrangements. Sequent does not designate its derivative instruments to manage risk exposure to energy prices as hedges under SFAS 133. Our determination of fair value considers various factors, including closing exchange or over-the-counter market price quotations, time value and volatility factors underlying options and contractual commitments. The maturities of these financial instruments are less than two years and represent purchases (long) of 411.3 billion cubic feet and sales (short) of 382.4 billion cubic feet.

The following table includes the fair values and average values of Sequent's energy marketing and risk management assets and liabilities as of June 30, 2003. We base the average values on a monthly average for the six months ended June 30, 2003.

	Asset			Liability		
	Average Values		Value at June	Average Values		Value at June
In millions	Three-Months	Six-Months	30, 2003	Three-Months	Six-Months	30, 2003
Natural gas contracts	$16.5	$15.2	$11.6	$15.7	$17.8	$11.4

Sequent employs a systematic approach to the evaluation and management of the risks associated with its contracts related to wholesale marketing and risk management, including value at risk (VaR). VaR is defined as the maximum potential loss in portfolio value over a specified time period that is not expected to be exceeded within a given degree of probability. Sequent uses both a 1-day and 20-day holding and a 95% confidence interval to evaluate its VaR exposure. A 95% confidence interval means there is a 5% probability that the actual change in portfolio value will be greater than the calculated VaR value.

Sequent calculates VaR based on the variance-covariance technique. This technique requires several assumptions for the basis of the calculation, such as price volatility, confidence interval, and holding period. Sequent's VaR may not be comparable to a similarly titled measure of another company, because although VaR is a common metric in the energy industry, there is no established industry standard for calculating VaR or for the assumptions made.

Sequent's open exposure is managed in accordance with established policies that limit market risk and require daily reporting of potential financial exposure to the chief risk officer. Because Sequent generally manages physical gas assets and economically protects its positions by hedging in the futures markets, Sequent's open exposure is generally minimal and as a result Sequent can operate within relatively low VaR limits. Sequent employs daily risk testing using both VaR and stress testing to evaluate the risks of its open positions.

Based on a 95% confidence interval and employing a 1-day and a 20-day holding period for all positions, Sequent's portfolio of positions for the three and six months ended June 30, 2003 had a 1-day holding period VaR and 20-day holding period VaR of:

	Three months ended June 30, 2003		Six months ended June 30, 2003	
	1-day	20-day	1-day	20-day
Period end	$0.1	$0.8	$0.1	$0.8
Average for period	0.2	0.2	0.2	0.4
High	0.4	1.0	2.5	6.7
Low (1)	0.0	0.0	0.0	0.0

(1) $0.0 values represent amounts less than $0.1 million.

Sequent's management actively monitors open commodity positions and the resulting VaR. Sequent continues to maintain a relatively matched book with minimal open commodity risk.

Under our risk management policy, we attempt to mitigate substantially all of our commodity price risk associated with Sequent's storage gas portfolio to lock in the economic margin at the time we enter into gas purchase transactions for our storage gas. We purchase gas for storage when the difference in the current market price we pay to buy gas plus the cost to store the gas is less than the market price we could receive in the future, resulting in a positive net profit margin. We use contracts to sell gas at that future price to substantially lock-in the profit margin we will ultimately realize when the stored gas is actually sold. These contracts meet the definition of a derivative under SFAS 133. The purchase, storage and sale of natural gas is accounted for differently than the derivatives we use to mitigate the commodity price risk associated with our storage portfolio. The difference in accounting can result in volatility in our reported net income, even though the economic margin is essentially unchanged from when the transactions were consummated. We do not currently use hedge accounting under SFAS 133 to account for this activity.

Gas that we purchase and inject into storage is accounted for at the lower of average cost or market as inventory in our condensed consolidated balance sheet, and is no longer marked to market following our implementation of the accounting guidance in EITF 02-03. Under EITF 02-03 we would recognize a loss in any period when the market price for gas is lower than our carrying amount for our purchased gas inventory. Costs to store the gas are recognized in the period the costs are incurred. We recognize revenues and cost of gas sold in our condensed statements of consolidated income in the period we sell gas and it is delivered out of the storage facility. The derivatives we use to mitigate commodity price risk and substantially lock in the margin upon sale of storage gas are accounted for at fair value and marked to market each period, with changes in fair value recognized as gains or losses in the period of change. This difference in accounting, the accrual basis for our storage gas inventory versus mark to market accounting for the derivatives used to mitigate commodity price risk, can result in volatility in our reported net income. Over time, gains or losses on the sale of storage gas inventory will be offset by losses or gains on the derivatives, resulting in our realization of the economic profit margin we expected when we entered into the transactions. This accounting difference causes Sequent's earnings on its storage gas positions to be affected by natural gas price changes, even though the economic profits remain essentially unchanged. Based on Sequent's storage positions at June 30, 2003, a $0.10 forward NYMEX price change would result in a $0.6 million pre-tax impact to Sequent's earnings.

Energy Investments. SouthStar manages a portion of its commodity price risks through hedging activities using derivative financial instruments and physical commodity contracts. SouthStar uses financial contracts in the form of futures, options and swaps to hedge the price volatility of natural gas. These derivative transactions qualify as cash flow hedges and SouthStar records the fair value of the open positions in its balance sheet with the unrealized gain or loss in other comprehensive income.

Ninety-four percent of SouthStar's residential and commercial customers buy gas on a variable pricing basis and six percent buy gas on a fixed price basis. SouthStar hedges the price risk associated with these fixed price sales using physical contracts and derivative instruments.

Interest Rate Risk

Interest rate fluctuations expose our variable-rate debt to changes in interest expense and cash flows. Our policy is to manage interest expense using a combination of fixed and variable rate debt. To facilitate the achievement of desired fixed and variable rate debt percentages (of total debt), AGL Capital entered into interest rate swaps where it agreed to exchange, at specified intervals, the difference between fixed and variable amounts calculated by reference to agreed-upon notional principal amounts. These swaps are designated to hedge the fair values of $100.0 million of the senior notes due 2011 and $75.0 million of the $150.0 million Trust Preferred Securities.

Market Value of Interest Rate Swap Derivatives

In millions

				Market Value as of:	
Notional Amount	Fixed Rate Payment	Variable Rate Received	Maturity	June 30, 2003	December 31, 2002
$75.0	8.0%	3 Month LIBOR Plus 131.5 bps	May 15, 2041	$6.7	$6.1
100.0	7.1%	6 Month LIBOR Plus 340.0 bps	January 14, 2011	2.3	$-

AGL Resources' variable-rate debt consists of commercial paper, Sequent's line of credit and the swapped portion of the $300.0 million senior notes due 2011 and $150.0 million trust preferred securities, which totaled $140.0.0 million, $7.5 million and $175.0 million, respectively, as of June 30, 2003. Based on outstanding borrowings at quarter-end, a 100 basis point change in market interest rates from 1.2% to 2.2% at June 30, 2003 would result in a change in annual pre-tax expense or cash flows of $3.2 million. As of June 30, 2003, $95.3 million of long-term fixed debt obligations mature in the following 12 months. Any new debt obtained to refinance this obligation would be exposed to changes in interest rates.

Credit Risk

Distribution Operations. AGLC has a concentration of credit risk related to the provision of services to Georgia's Marketers. AGLC bills ten Marketers in Georgia for services. These Marketers, in turn, bill end-use customers. Credit risk exposure to Marketers varies with the time of the year. Exposure is lowest in the non-peak summer months and highest in the peak winter months. The provisions of AGLC's tariff allow AGLC to obtain security support in an amount equal to a minimum of two times a Marketer's highest month's estimated bill from AGLC.

In addition, AGLC bills intrastate delivery service to the Marketers in advance rather than in arrears. We provide security support in the form of cash deposits, letters of credit/surety bonds from acceptable issuers and corporate guarantees from investment grade entities. The RMC reviews the adequacy of security support coverage, credit rating profiles of security support providers and payment status of each Marketer on a monthly basis. We believe that adequate policies and procedures have been put in place to properly quantify, manage and report on AGLC's credit risk exposure to Marketers.

AGLC also faces potential credit risk in connection with assignments to Marketers of interstate pipeline transportation and storage capacity. Although AGLC assigned this capacity to the Marketers, in the event that the Marketers fail to pay the interstate pipelines for the capacity, the interstate pipelines would in all likelihood seek repayment from AGLC. The fact that some of the interstate pipelines require the Marketers to maintain security for their obligations to the interstate pipelines arising out of the assigned capacity somewhat mitigates this risk.

Concentration of credit risk occurs at AGLC, where we charge out and collect from Marketers and poolers costs for our distribution operations segment. For the six months ended June 30, 2003, the four largest Marketers based on customer count, one of which is our partially owned affiliate, accounted for approximately 55.1% of our operating margin and 61.5% of distribution operations' operating margin.

Wholesale Services. Sequent established credit policies to determine and monitor the credit-worthiness of counterparties, as well as the quality of pledged collateral and use of master netting agreements whenever possible to mitigate exposure to counterparty credit risk. Master netting agreements enable Sequent to net certain assets and liabilities by counterparty. Sequent also nets across product lines and against cash collateral provided that the master netting and cash collateral agreements include such provisions. Additionally, Sequent may require counterparties to pledge additional collateral when deemed necessary. We conduct credit evaluations and obtain appropriate approvals for our counterparty's line of credit before any transaction with the counterparty is executed. In most cases, the counterparty must have a minimum long-term debt rating of Ba3 from Moody's and BBB- from S&P. Transaction counterparties that do not have either of the above ratings require credit enhancements by way of guaranty, cash deposit or letter of credit.

Sequent, which provides services to Marketers, utility and industrial customers, also has a concentration of credit risk measured by 60-day receivable exposure. By this measure, Sequent's top 20 counterparties represent approximately 76% of the total exposure of $242 million. All of Sequent's counterparties are assigned internal ratings determined from the counterparty's external ratings with Standard & Poor's and Moody's. The internal rating is multiplied by the counterparty's credit exposure with Sequent and divided by our total counterparty credit exposure. As of June 30, 2003, Sequent's counterparties or the counterparty's guarantor have a weighted average Standard & Poor's equivalent credit rating of BBB. The following table shows Sequent's commodity receivable and payable positions as of June 30, 2003 and December 31, 2002.

Gross receivable

In millions	As of: June 30, 2003	December 31, 2002	Change
Receivables with netting agreements in place:			
Counterparty is investment grade	$214.1	$188.2	$25.9
Counterparty is non-investment grade	24.0	22.8	1.2
Counterparty has no external rating	6.6	25.1	(18.5)
Receivables without netting agreements in place:			
Counterparty is investment grade	3.1	3.7	(0.6)
Counterparty is non-investment grade	-	0.4	(0.4)
Counterparty has no external rating	0.1	-	0.1
Amount recorded on balance sheet	$247.9	$240.2	$7.7

Gross payable

In millions	As of: June 30, 2003	December 31, 2002	Change
Payables with netting agreements in place:			
Counterparty is investment grade	$181.1	$139.8	$41.3
Counterparty is non-investment grade	50.4	36.6	13.8
Counterparty has no external rating	27.2	28.4	(1.2)
Payables without netting agreements in place:			
Counterparty is investment grade	23.7	37.4	(13.7)
Counterparty is non-investment grade	9.3	2.2	7.1
Counterparty has no external rating	1.7	6.3	(4.6)
Amount recorded on balance sheet	$293.4	$250.7	$42.7

Energy Investments. SouthStar has a year-to-date average of 572,991 customers, comprising approximately 38% of the Georgia residential market. SouthStar has established credit guidelines and risk management for each customer type:

- We score firm residential and small commercial customers using a national reporting agency and enroll, without security, only those customers that meet or exceed SouthStar's credit threshold.
- We investigate potential interruptible and large commercial customers through reference checks, review of publicly available financial statements and review of commercially available credit reports.
- We assign physical wholesale counterparties an internal credit rating and credit limit prior to entering into a physical transaction based on their Moody's, S&P and Fitch rating, commercially available credit reports and audited financial statements.

Item 4. Controls and Procedures

Evaluation of disclosure controls and procedures. Our chief executive officer and chief financial officer, after evaluating the effectiveness of our "disclosure controls and procedures" (as defined in the Securities Exchange Act of 1934 Rules 13a-14(c) and 15d-14(c)) as of the end of the period covered by this quarterly report (the "Evaluation Date"), have concluded that our disclosure controls and procedures were effective in timely alerting them to material information relating to us (including our consolidated subsidiaries) which were required to be included in our periodic SEC filings.

(b) *Changes in internal controls over financial reporting*. There were no changes in our internal control over financial reporting that occurred during our most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

PART II -- OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

The nature of our business and its subsidiaries ordinarily results in periodic regulatory proceedings before various state and federal authorities and/or litigation incidental to the business. For information regarding pending federal and state regulatory matters, see "Regulatory and Legislative Overview" contained in Item 2 of Part I under the caption, "Management's Discussion and Analysis of Financial Condition and Results of Operations."

On July 1, 2003, the city of Augusta, Georgia served AGLC with a complaint that was filed in the Superior Court of Richmond County, Georgia against AGLC. Augusta's allegations include fraud and deceit and damages to realty. The allegations arise from negotiations between the city and AGLC regarding our environmental cleanup obligations connected with AGLC's former manufactured gas plant operations in Augusta. The city of Augusta seeks relief in the form of damages including an amount to be determined by a jury for the alleged fraud and deceit, together with attorney fees and punitive damages. We believe the claims asserted in this complaint are without merit, and we have remained in active settlement negotiations with the City. For more information about the manufactured gas plants and our environmental cleanup obligations, please see Item 1, Financial Statements, Note 2 "Regulatory Assets and Liabilities – Environmental Matters."

With regard to other legal proceedings, we are a party, as both plaintiff and defendant, to a number of other suits, claims and counterclaims on an ongoing basis. Management believes that the outcome of all such litigation in which it is involved will not have a material adverse effect on our consolidated financial statements.

ITEM 2. CHANGES IN SECURITIES AND USE OF PROCEEDS

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

We held our annual meeting of shareholders in Atlanta, Georgia on April 16, 2003. Holders of an aggregate of 56,777,909 shares of our common stock at the close of business on February 13, 2003 were entitled to vote at the meeting, of which 49,301,493 were represented in person or by proxy. At the annual meeting, our shareholders were presented with one proposal, as set forth in our Proxy Statement.

Our shareholders voted as follows and elected the following three director nominees who will serve a three-year term until our Annual Meeting in 2006.

	For	Withheld	Broker Non-Vote
Charles R. Crisp	48,717,857	583,636	-
Wyck A Knox, Jr.	48,393,264	908,229	-
Dennis M. Love	47,629,734	1,671,758	-

ITEM 5. OTHER INFORMATION

None.

PART II -- OTHER INFORMATION - Continued

ITEM 6. EXHIBITS AND REPORTS ON FORM 8-K

(a) Exhibits

3.2 AGL Resources Inc. Bylaws, as amended April 16, 2003.

10.1.a Separation agreement dated April 5, 2003 by and between Richard J. Duszynski and AGL Resources Inc.

10.1.b Form of Amendment No. 1 to Continuity Agreement between AGL Resources Inc. and certain executive officers.

10.1.c Amendment No. 1 to Continuity Agreement between AGL Resources Inc. and Paula G. Rosput.

10.1.d Form of AGL Resources Inc. Executive Post Employment Medical Benefit Plan

10.2* Amended and Restated Master Environmental Management Services Agreement dated July 25, 2002 by and between Atlanta Gas Light Company and The RETEC Group, Inc.

10.3 Guaranty Agreement, effective March 25, 2003, by and between Atlanta Gas Light Company and AGL Resources Inc.

10.4 364 Day Credit Agreement with a one year term-out option, dated June 16, 2003, by and between AGL Resources Inc., as Guarantor, AGL Capital Corporation, as Borrower, and the Lenders named therein.

10.5 Guarantee dated June 16, 2003, by and between AGL Resources Inc., the Guarantor and SunTrust Bank, as Administrative Agent for the Lenders named in the 364 Day Agreement with a one year term-out option, dated June 16, 2003 by and between AGL Capital Corporation, as Borrower and the Lenders named therein.

31 Rule 13a-14(a)/15d-14(a) Certifications

32 Section 1350 Certifications

* Confidential treatment pursuant to 17 CFR Section 200.80 (b) and 240.24b-2 has been requested regarding certain portions of the indicated Exhibit, which portions have been filed separately with the Commission.

(b) Reports on Form 8-K.

Date	Event Reported
April 22, 2003	Furnished, under Item 9 – Regulation FD Disclosure, our earnings results for the three months ended March 31, 2003 which included our condensed statements of consolidated income for the Three Months Ended March 31, 2003 and 2002 and our EBIT schedule for the Three Months Ended March 31, 2003 and 2002
April 24, 2003	Announced, under Item 5 – Other Events that Karen R. Osar resigned from our Board of Directors.
June 27, 2003	Furnished, under Item 9 – Regulation FD Disclosure, AGL Resources press release announcing AGL Capital Corporation's issuance and pricing of $225 million of senior notes at an interest rate of 4.45%.

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

AGL RESOURCES INC.
(Registrant)

Date: July 31, 2003

/s/ Richard T. O'Brien
Executive Vice President and Chief Financial Officer

BEFORE THE TENNESSEE REGULATORY AUTHORITY

NASHVILLE, TENNESSEE

October 7, 1998

IN RE:	)	
PETITION OF CHATTANOOGA GAS	)	
COMPANY TO PLACE INTO EFFECT	)	**DOCKET NO. 97-00982**
A REVISED NATURAL GAS TARIFF	)	
	)	

ORDER

MELVIN J. MALONE
CHAIRMAN

H. LYNN GREER, JR.
DIRECTOR

SARA KYLE
DIRECTOR

TABLE OF CONTENTS

INDEX OF TABLES

IN RE: PETITION OF CHATTANOOGA GAS COMPANY TO PLACE INTO EFFECT A REVISED NATURAL GAS TARIFF, DOCKET NO. 97-00982

This matter came before the Tennessee Regulatory Authority (hereafter the "Authority") upon the Petition of the Chattanooga Gas Company (hereafter the "Company" or "Chattanooga Gas"), a wholly owned subsidiary of Atlanta Gas Light Company, Inc. (hereafter "AGL") for a general rate increase. This matter was heard by the Authority from February 9 to 13, 1998.

I. PROCEDURAL BACKGROUND

On May 1, 1997, Chattanooga Gas Company, filed a Petition with the Authority pursuant to Tenn. Code Ann. § 65-5-203, to place into effect a revised natural gas Tariff, superseding its existing tariff and rate schedule presently filed with the Authority. On May 23, 1997, the Consumer Advocate Division, Office of the Attorney General (hereafter known as the "Advocate"), filed its Petition to Intervene and Participate as a Party. On June 25, 1997, Associated Valley Industries group (hereafter known as "AVI"), a coalition of certain industrial users of natural gas, filed a Petition to Intervene. The Petitions for leave to intervene from the Advocate and from AVI were granted at the Authority Conference on July 1, 1997, and Director Melvin J. Malone was appointed Hearing Officer in this matter. On July 23, 1997, Chattanooga Manufacturers Association (hereafter known as "CMA") filed its Petition for Leave to Intervene.

On August 6, 1997, a Pre-Hearing Conference was held before Authority Director Melvin J. Malone. At that Pre-Hearing Conference the admission of CMA as a party to the proceeding was approved. On August 13, 1997, a Report and Recommendation from the Hearing Officer was submitted to the Authority providing dates for the submission of any additional data requests and responses, for the filing of additional direct and rebuttal testimony, and for a Hearing. By Order, dated September 3, 1997, the Authority adopted the procedural schedule set forth in the Hearing Officer's Report and Recommendation with amendments. The Authority set this matter for Hearing from October 13 through 17, 1997. On October 2, 1997, the Parties submitted a joint motion to continue the Hearing dates to a date to be determined by the Authority. At the Authority Conference on October 7, 1997, the motion was granted and Chattanooga Gas, through its counsel, waived its right under Tenn. Code Ann. § 65-5-203(b)(1), to place the proposed rate increase into effect within six (6) months of the date of the initial tariff filing.

On October 7, 1997, a Pre-Hearing Conference was held before Director Melvin J. Malone in his capacity as Hearing Officer. On October 29, 1997, a Report and Recommendation was submitted to the Authority from the Hearing Officer providing dates for the Hearing. By Order, dated January 30, 1998, the Authority adopted the Hearing schedule set forth in the Report and Recommendation. This matter was set for Hearing by the Authority from February 9 to 13, 1998.

II. HEARING AND APPEARANCES

On February 9 to 13, 1998, a Hearing was convened before the Directors of the Authority, at which time, the following appearances were entered by counsel:

FOR THE COMPANY:

William L. Taylor, Jr., Esq.
Spears, Moore, Rebman & Williams
P.O. Box 1749
Chattanooga, TN 37401

Gene Shiles, Esq.
Spears, Moore, Rebman & Williams
P.O. Box 1749
Chattanooga, TN 37401

L. Craig Dowdy, Esq.
Long, Aldrich & Norman, L.L.P.
303 Peachtree Street, Suite 5300
Atlanta, GA 30308

FOR THE ADVOCATE:

L. Vincent Williams, Esq.
Office of the Attorney General
426 - 5th Avenue, North
Nashville, TN 37243-0485

Vance Broemel, Esq.
Office of the Attorney General
426 - 5th Avenue, North
Nashville, TN 37243-0485

FOR AVI and CMA:

Henry Walker, Esq.
Boult, Cummings, Conners & Berry
414 Union Street, Suite 1600
Nashville, TN 37219

Dave Higney
Grant, Konvalinka & Harrison
633 Chestnut Street
Chattanooga, TN 37401

The Company presented testimony from Harrison F. Thompson, Kenneth A. Royse, H. Edwin Overcast, Gerald A. Hinesley, Victor L. Andrews, Donald S. Roff, Fred A. Carillo, Lisa E. Howard Wooten, Gregory E. Aliff, and James E. Kissel. AVI and CMA presented the testimony of Donald E. Johnstone, Michael Gorman, James Selecky, Robert Colby, Harry Faulkner III, Thomas E. Hodge, and Donald E. Huffman. The Advocate presented the testimony of Dr. Stephen N. Brown, Archie R. Hickerson, Daniel W. McCormac, and R. Terry Buckner.

At the Authority Conference on July 7, 1998, the Directors of the Authority, after public deliberation, announced their decision in this matter pursuant to Tenn. Code Ann. § 4-5-314.

III. LEGAL BACKGROUND AND CRITERIA FOR ESTABLISHING JUST AND REASONABLE RATES

The Authority considers petitions seeking adjustments of rates and charges under Tenn. Code Ann. § 65-5-203, which requires:

> 1) That the Authority shall have the power upon written complaint, or upon its own initiative, to hear and determine whether the increase, change or alteration being sought by a public utility is just and reasonable;[1]
>
> 2) That the burden of proof to show that the increase, change or alteration is just and reasonable shall be on the public utility making the same; and
>
> 3) In determining whether such increase, change or alteration is just and reasonable, the Authority shall take into account the safety, adequacy and efficiency or lack thereof of the service or services furnished by the public utility.

The Authority has wide latitude in setting rates for public utilities under its jurisdiction. C.F. Industries v. Tennessee Public Service Commission, 599 S.W.2d 536 (Tenn. 1980). The court in C.F. Industries stated that, "[T]he process of setting rates is not required to follow any particular course, so long as the end result does not violate the just and reasonable standard." Id. at 543 (quoting Allied Chemical Corp. v. Georgia Power Co., 224 S.E.2d 396, at 399 (Ga. 1976)).

---

1 The TRA has the power to fix just and reasonable rates "which shall be imposed, observed, and followed thereafter" by any public utility. Tenn. Code Ann. § 65-5-201. Consumer Advocate Division v. Tennessee Regulatory Authority, No. 01-A-01-9708-BC-00931, op. at 6 (Tenn.Ct. App., July 1, 1998) (further citing Consumer Advocate Division V. Bissell, No. 01-A-01-9601-BC-00049 (Tenn. Ct. App., Aug. 26,1996)).

IV. TEST PERIOD

In a rate case the Authority must, as a preliminary determination, decide which test period is appropriate. The purpose in the selection of a test period is to provide an indication of the rate of return that is likely to be produced under the existing rate structure in the reasonably foreseeable future. The test period takes into consideration the estimated effect of reasonably expected revenues, expenses and investments.

The Company proposed a historical test period for the twelve (12) months that ended September 30, 1996, with adjustments for attrition through September 30, 1998. Each of the Parties in this case adopted this same test period for their forecasts. The Authority concludes, therefore, that this is a reasonable and appropriate test period in this case for rate setting purposes.

V. CONTESTED ISSUES

In its original filing, the Company requested a rate increase of $4,422,602. The Advocate asserted that a rate increase was not just and that the Company should be ordered to reduce current rates by $1,393,407.[2] AVI and CMA asserted that the Company could justify only a $6,399 increase.[3] The following sections represent the issues contested by the Parties.

V(a). RATE BASE

Rate Base is the Company's net investment, which is financed through investor supplied funds, in property used and useful in providing utility service. This is the amount of investment on which the Company should be allowed the opportunity to earn a fair and reasonable rate of return. The Company forecasted a Rate Base of $101.4 million, while the Advocate and AVI proposed $94.6 million and $87.7 million, respectively.

V(a)1. PLANT IN SERVICE AND CONSTRUCTION WORK IN PROGRESS

Plant in Service represents the original investment cost to the Company of the assets used in providing utility service. Construction Work in Process ("CWIP") represents the cost of investment that is currently under construction and will be transferred to Plant in Service when completed.

The actual balance in this account at September 30, 1996, was $125,916,379 to which the Company forecasted additions of $14,098,556 through the midpoint of the attrition year. The Company provided a detailed project by project breakdown of the plant additions budgeted for

---

2 See Advocate Pre-Filed Exhibit, Schedule 1.

3 In Table 1 of AVI witness Michael Gorman's testimony, AVI proposed a zero ($0) rate change. The calculations which result derive a rate increase of $6,399. The difference can be attributed to rounding.

1997 and 1998. The Advocate used a "simple average" of previous plant additions to develop Utility Plant in Service that resulted in its Plant In Service forecast being $0.600 million higher than the Company's budgeted forecast. AVI accepted the Company's forecasted amount for Plant In Service and CWIP. Additionally, no testimony was presented on these issues at the Hearing, either in direct or rebuttal testimony. Since the Company's attrition forecast of $140,014,935 is supported by a detailed budget and workpapers, the Directors unanimously approved the Company's forecast.

V(a)2. ACQUISITION ADJUSTMENT

An Acquisition Adjustment represents the amount of investment by the utility that is over and above the original cost of assets placed in service. On September 30, 1988, Atlanta Gas Light Company purchased the assets of Chattanooga Gas from Jupiter Corporation for $35 million, plus $1,279,456 in legal and accounting fees, for a total of $36,279,456. The purchase price exceeded the Company's September 30, 1988, book value of $22,653,104 by $13,626,352, which represents the total acquisition adjustment. Chattanooga Gas has been amortizing this acquisition adjustment over a 40-year period, and as of May 1, 1997, the unamortized balance was $9,553,422.

Chattanooga Gas requested that the Authority recognize the unamortized balance of the acquisition adjustment, $9,553,422, in Rate Base. Additionally, the Company requested that the annual amortization of $411,024 be included in Cost of Service. This is the first time that the Company has asked for recognition of the acquisition adjustment in the Rate Base and Cost of Service from September 1988 to the present.[4] In support of its request, the Company stated that the facts that existed at the time AGL first purchased the Chattanooga system have drastically changed. For example, the Company argues that extensive improvements and efficiencies were

[4] Chattanooga Gas Company Post-hearing Brief, at page 7.

realized because of the acquisition. The Company p‹ovided supporting schedules showing savings to the ratepayers resulting from the acquisition. Finally, the Company portrayed the favorable results of its management audit and customer surveys as proof that the operations of Chattanooga Gas have improved to the ratepayers' benefit.

The Advocate opposed recognizing the Acquisition Adjustment for ratemaking purposes. The Advocate argued that recognizing the Acquisition Adjustment would force Chattanooga Gas' ratepayers to pay twice for assets that had been "over-depreciated" for book purposes. Additionally, the Advocate argued that the Company's exhibits showing savings to the ratepayers from the acquisition were in error. The Advocate highlighted errors in the Company's original exhibit quantifying the savings to ratepayers since the acquisition. The Advocate refined its original schedules to illustrate that customers of Chattanooga Gas were in a less favorable position after the acquisition by AGL. On September 10, 1997, the Company filed a revised exhibit that eliminated several of these errors. The Directors found that this later filing, however, still contained incorrect calculations. The Advocate maintained that correcting these errors revealed that additional payments in excess of benefits would have to be made by the ratepayers.

AVI opposed recognizing the Acquisition Adjustment in the Company's Cost of Service. The arguments advanced by AVI in opposition to the Acquisition Adjustment were structurally identical to those of the Advocate.

The Directors found that while the level of service provided by Chattanooga Gas may have increased from that of the Company's previous owners, such increases in service quality originated from investments in plant made by the current owners. This increase in investment, and therefore the change in service, has been recognized through increases to the Plant in Service component of Rate Base on which a fair rate of return is provided. The Directors also found that the Company's arguments for recognition of an Acquisition Adjustment ten (10) years after the acquisition by AGL, were not dispositive of the issue. Therefore, the Directors of the Authority unanimously denied the Company's request to include an Acquisition Adjustment in the Rate Base.

V(a)3. CASH

Utility companies, including Chattanooga Gas, are required by their financial institutions to maintain certain minimum cash balances in order to avoid service charges. This cash balance represents an asset, supplied by the investors of the Company, and has been traditionally recognized by this agency as an addition to Rate Base. The Company included $2,373,422 as the cash element of their Rate Base. This amount represents the average daily balance of their cash accounts, and correctly ties to the Company's ledger. Although the Advocate accepted the Company's calculation of cash, AVI objected to including cash in the Rate Base calculation. Michael Gorman, AVI's witness, stated in his direct testimony that the Company did not demonstrate that this minimum cash bank balance is necessary to avoid service charges.[5] In his testimony, however, Mr. Gorman used the phrase "this minimum cash bank balance,"[6] suggesting that a cash balance is warranted. Mr. Gorman, on behalf of AVI, only offered zero dollars as an alternative. The Company did not dispute AVI's objection in their rebuttal testimony.

A majority of the Directors found that utility companies are typically required to maintain minimum cash balances in order to avoid service charges, and that this Agency has traditionally recognized and approved cash balances of this type as an addition to Rate Base. A majority of the Directors concluded that it would be a contradiction to accept zero dollars as being reasonable, as

---

5 Michael Gorman Pre-Filed Direct Testimony, at page 17.
6 Id., at page 6.

suggested by AVI. For these reasons, the majority of Directors adopted the Company's position of $2,373,422 as the appropriate cash element to include in Rate Base. [7]

V(a)4. MATERIALS AND SUPPLIES

Materials and Supplies ("M&S") generally refers to construction inventories. M&S includes items such as pipes, meters, and other equipment that will soon be placed into service. M&S can also include items that are kept on hand for emergency purposes.

The Company included its twelve (12) month historical average balance for M&S during the test period to arrive at its forecast of M&S. This amount was also accepted by AVI. Since the Advocate did not testify concerning their methods used to calculate M&S of $346,273, or oppose the Company's position, the Authority unanimously adopted the Company's forecast of $453,221 as the appropriate amount for M&S to include in Rate Base.

V(a)5. GAS INVENTORIES

Gas inventories represent the average value of gas that the Company stores for withdrawal during the peak winter months. While the actual cost of the gas placed into storage is recovered through the Authority's purchased gas adjustment ("PGA") process, the return on the investment required to store gas in inventory is recovered through a rate case proceeding.

The Company has included the twelve (12) month historical average balance during the test period of $5,419,144 to arrive at its forecast of gas inventories. This amount was also accepted by AVI. Because the Advocate did not present any testimony or offer any evidence regarding its calculation of its $6,659,404 forecast of gas inventory,[8] the Directors unanimously approved the Company's forecast of $5,419,144.

---

7 Director Kyle voted no on this issue.

8 Consumer Advocate Pre-Filed Exhibit, Schedule 3.

V(a)6. DEFERRED RATE CASE EXPENSE

Deferred Rate Case Expense represents the unamortized portion of costs the Company has incurred for regulatory proceedings before the Authority. This item also includes Chattanooga Gas' share of its total cost of proceedings before the Federal Energy Regulatory Commission ("FERC"). In addition, costs relating to the Company's Management Audit, which was ordered by the Tennessee Public Service Commission in the Company's last rate case, are included in this item. The Company capitalizes these costs and amortizes them over a previously prescribed period. The amortization of these costs is then treated on the income statement as an expense.

The Company has taken the balance in this account at September 30, 1996, added its estimated outside costs for completing this rate case of $183,500, and continued with its current monthly amortization of $1,288 to arrive at its average Deferred Rate Case Expense of $200,668 in the attrition year for Rate Base. However, in computing Rate Case Expense for the Net Operating Income ("NOI"), the Company chose to increase the test period amount by their growth factor. The Company also excluded the deferred costs of their Management Audit in their forecast.

The Advocate included $47,309 in Rate Base for their forecast of Deferred Rate Case Expense. The Advocate's calculations of $144,500[9] did not recognize the cost of the management audit. AVI accepted the Company's calculation of Deferred Rate Case Expense.

The Directors determined that the balance of the Deferred Rate Case Expense should relate to the amortization included as Rate Case Expense in the computation of Net Operating Income. To compute this item, the Directors concluded that the beginning balance should first be increased

9 There is no evidence in the record regarding how or why the Advocate chose to change the Company's original forecast of $183,500.

by the estimated cost of this case and then amortized over a new three (3) year period as illustrated below:

DEFERRED RATE CASE EXPENSE

9/30/96 Deferred Rate Case Expense	$38,420
9/30/96 Deferred Management Audit Expense	135,744
Estimated Costs to Complete 1997 Rate Case	183,500
Total Deferred Balance	**$357,664**
Amortization Period (Years)	3
Annual Rate Case Expense	**$119,221**
Monthly Rate Case Expense	$9,935
Months from 9/30/96 to 3/31/98[10]	18
Total Amortization at 3/31/98	**$178,830**
Total Deferred Balance	$357,664
Amortization through 3/31/98	178,830
Deferred Rate Case Expense at 3/31/98	**$178,834**

The Directors found that they could not accept any one method proposed by the Parties for Deferred Rate Case Expense, and then ignore this calculation in the development of Rate Case Expense for Net Operating Income. The Directors, therefore, determined and adopted $178,834 as the proper forecast for Deferred Rate Case Expense, and $119,221 as the proper forecast for Rate Case Expense.

V(a)7. PREPAYMENTS

Prepayments are an investment in working capital that are made in advance of the period to which they apply and include items such as prepaid rents, insurance, and taxes. The amortization of these costs are then treated on the income statement as an expense.

10 March 31, 1998, represents the midpoint of the attrition year (October 1, 1997 -- September 30, 1998). Therefore, March 31, is the appropriate point in time to measure the Company's net investment against their earnings.

The Company included $1,189,348 representing the test period average of this account from October 1995 to September 1996 as its forecast of Prepayments during the attrition year. AVI accepted the Company's forecast in their Exhibits. The Advocate included only $769,193 in its Exhibits for Prepayments. Further, the Advocate presented no testimony or rationale on the methodology behind its forecast for Prepayments. The Advocate presented no cross-examination of any witness at the Hearing or made mention of this issue in its post-hearing briefs.

Since the Company's forecast of $1,189,348 represents the test period average of this account for October 1995 to September 1996, the Directors unanimously adopted the Company's forecast as the proper estimate for Prepayments.

V(a)8. OTHER ACCOUNTS RECEIVABLE

The category "Other Accounts Receivable" represents amounts owed to the Company by their customers that are not associated with regular gas service. An example of Other Accounts Receivable would be for amounts due from customers for main extensions that are being paid on an installment basis.

The Company included $92,028 representing the test period average of this account for October 1995 to September 1996 in Rate Base as its forecast of Other Accounts Receivable during the attrition year. AVI accepted the Company's forecast. The Advocate included $138,738 in its case for Other Accounts Receivable. However, the Advocate presented no testimony or rationale regarding the calculation of its forecast. The Directors were not presented with cross-examination of any witness at the Hearing relating to this issue.

Because the Directors found no evidence to support any other forecast, the Directors unanimously adopted the Company's forecast as the proper estimate for Other Accounts Receivable.

V(a)9. LEAD LAG STUDY

The Lead/Lag Study measures the average amount of capital provided by investors, over and above the investment in other Rate Base issues, to finance company activities between the time expenditures are required to provide services and the time collections are received for services. The Lead/Lag Study recognizes that there is an investment required on the part of the stockholders to pay for the day-to-day expenses of the utility before they are recovered through rates charged to the ratepayer.

Each of the Parties adopted the Company's Revenue Lag Day forecast of 41.60 days. However, there arose a dispute over the proper number of expense lag days to include. The Advocate proposed a separate treatment on lag days for uncollectible expense, but offered no testimony regarding the rationale for this change. The Directors, therefore, unanimously accepted the position of the Company and AVI that lag days concerning uncollectible expense should be included with other operating expenses.

A second dispute concerned AVI's elimination of depreciation expense from the calculation of expense lag days. The Company and the Advocate each included Depreciation Expense in the Lead/Lag Study at zero (0) days. AVI contended that Accumulated Depreciation was already included in Rate Base and that the Company was already earning a return on those assets. However, the Directors recognized that including the Depreciation Expense in the Lead/Lag Study at zero (0) Lag Days is necessary to recognize that investor funding has occurred, but was not yet recovered. The Directors approved the positions of the Company and the Advocate on this item.

A third dispute involved the appropriate lag days for interest expense. The Company used zero lag days for this issue while the Advocate and AVI used 85.5 and 82.5 days, respectively. Because the Authority permitted the recognition of Interest Expense in the Lead/Lag Study in prior cases, the Directors determined that the recognition of Interest Expense should be recognized in this case. The Directors unanimously concluded, therefore, that Interest Expense should be included in the Lead/Lag Study at 84 days.

A final area of dispute involved the appropriate lag days for Preferred Dividends and Net Earnings. Including the preferred dividends and net earnings in the Lead/Lag Study recognizes that investor funding has occurred, but that it has not been recovered. AVI excluded these items from the Lead/Lag Study based on its characterization of them as non-cash expenditures.

The Directors found that consideration of each of the prior adjustments produces an Expense Lag of 38.46 days, resulting in a net lag day effect of 3.14 days. [11] In addition, multiplying the net lag days by the daily cost of service of $660,923 and taking incidental collections of $49,828 into consideration gives $266,399 for the results of the Lead/Lag Study.

LEAD/LAG STUDY RESULTS

	Company[12]	Consumer Advocate[13]	AVI[14]	Authority
Revenue Lag Days	41.60	41.60	41.60	41.60
Expense Lag Days	34.80	38.40	42.98	38.46
Net Lag Days	**6.80**	**3.20**	**-1.38**	**3.14**
Daily Cost of Service	$262,727	$248,986	$234,583	$226,399
Operating Funds Advanced	$1,786,544	$805,866	$-322,783	$710,751
Incidental Collections	-49,828	-49,828	-49,828	-49,828
Lead/Lag Study Results	**$1,736,716**	**$756,038**	**$-372,611**	**$660,923**

The Directors, therefore, adopted $660,923 as the appropriate amount to include for the Lead/Lag component of Rate Base.

---

11 Preferred dividends and net earnings are included in the Lead/Lag Study at 0 days.

12 Chattanooga Gas Exhibit 5, Schedule 8, Page 3 of 4.

13 Advocate Pre-Filed Exhibit, Schedule 5.

14 AVI Exhibit MPG-1, Schedule 8. However, on page 17 of his direct testimony, Mr. Gorman uses $396,530 for his Lead/Lag results. He then carries the $396,530 figure to his Rate Base calculation. This discrepancy remains unexplained.

V(a)10. ACCUMULATED DEPRECIATION

Recovery of the dollars invested in Plant in Service is permitted over the plant's estimated useful life by a systematic depreciation charge. The Accumulated Depreciation account represents the amount of plant that has already been recovered from utility customers through the annual Depreciation Expense charges on the income statement.

The Company applied the results of its Depreciation Study to its forecast of Plant in Service to calculate its Depreciation Expense and Accumulated Depreciation of $46,569,377. AVI accepted this same amount of Accumulated Depreciation. The Advocate included $46,478,394 as their forecast of Accumulated Depreciation. This figure is $90,983 less than the Company's calculation. According to the Advocate, this difference is due to using a "simple average" rather than a thirteen (13) month average to develop Accumulated Depreciation.[15]

In consideration of the Authority's previous acceptance of the Company's forecast of Plant in Service, see section (V(a)1.), of this Order, that was based upon a thirteen (13) month average, the Directors unanimously adopted the Company's companion forecast of $46,569,377 for Accumulated Depreciation.

V(a)11. ACCUMULATED AMORTIZATION OF ACQUISITION ADJUSTMENT

This item represents the Company's total accumulated amortization of their Acquisition Adjustment. Treatment of any Acquisition Adjustment governs the appropriate handling for the related Accumulated Amortization. Because of the action taken on the Acquisition Adjustment in section V(a)2. of this Order, the Directors determined that this issue was moot.

15 R. Terry Buckner Pre-Filed Direct Testimony, at page 18.

V(a)12. ACCUMULATED DEFERRED FEDERAL INCOME TAXES

The Directors found no disagreements among the Parties on the $5,131,816 amount of Accumulated Deferred Federal Income Taxes ("ADFIT") forecast by the Company. The Directors, therefore, unanimously adopted the Company forecast in the amount of $5,131,816 for ADFIT.

V(a)13. CUSTOMER ADVANCES FOR CONSTRUCTION

Customer Advances for Construction represent funds that are advanced from ratepayers for various construction projects. The Directors found no disagreement among the Parties over the forecast of Customer Advances, and unanimously adopted the Company's forecast of $384,855 as the proper amount for this account.

V(a)14. CONTRIBUTIONS IN AID OF CONSTRUCTION

Contributions In Aid of Construction represents funds that are received from ratepayers for certain construction projects. These projects are undertaken when the Company's facilities are either extended or relocated at the customer's request in an area that is not likely to be economically feasible to serve under normal conditions. The Company forecasted an attrition year balance of $1,908,645. AVI also used this amount in their calculation of Rate Base. The Advocate included $1,858,651 in its exhibit for Contributions In Aid of Construction. The Advocate, however, presented no testimony or other rationale regarding the calculation of its forecast. Since the Company's forecast reflects the actual test period average balance, and because the record was absent evidence to support any other calculation, the Directors unanimously adopted the Company's forecast of $1,908,645.

V(a)15. RESERVE FOR UNCOLLECTIBLE ACCOUNTS

The Company included $278,723 in their Reserve for Uncollectible Accounts based on the development of an uncollectible factor that was then applied to estimated revenues for the attrition period. While AVI accepted the Company's forecast for this issue, the Advocate projected an uncollectible reserve balance of $257,864.

Based on the record, a majority of the Directors concluded, that it is reasonable that a Company with net revenues forecasted in excess of $32 million may establish a bad debt reserve of $257,864 or approximately 8/10ths of 1 percent of its projected revenue. Additionally, the majority concluded that, based on the Company's past bad debt experience, its estimate for the attrition period was reasonable. Further, the majority restated that no party challenged the Company's estimate, except the small undocumented adjustment by the Advocate. Therefore, a majority of the Directors adopted Chattanooga Gas' attrition period Reserve for Uncollectible Accounts in the amount of $278,723.[16]

V(a)16. OTHER RESERVES

Other Reserves represents an allowance that the Company has established for maintenance of their liquefied natural gas (LNG) facility. This allowance represents the net accumulation of expenses that were previously recognized in Net Operating Income, and must be deducted from Rate Base. The Company included $549,562 in their forecast for Other Reserves. This amount was also accepted by AVI in their forecast of Rate Base. The Advocate included $409,201 for Other Reserves. The record reflects that the Advocate presented neither testimony nor rationale on the methodology used to calculate their forecast. As the record supported the Company's forecast, the Directors unanimously adopted the forecast by Chattanooga Gas for Other Reserves in the amount of $549,562.

---

16 Director Kyle voted no on this issue.

V(a)17. CUSTOMER DEPOSITS

Customer Deposits represents funds received from ratepayers as security against potential losses arising from customer failure to pay for service. These funds represent a liability of the Company for repayment either after a specified period or upon satisfaction of certain credit requirements. These funds also represent a source of non-investor supplied capital, and must therefore be deducted from the Rate Base calculation.

The Company included $3,766,190 in their forecast of Customer Deposits. AVI accepted this amount in its forecast of Rate Base. The Advocate, however, adjusted Chattanooga Gas' forecast to reflect a balance of $1,917,229 based upon the Company's acknowledgment that it overstated its forecast of Customer Deposits. Since there were no disputes entered into the record by any of the Parties regarding the Advocate's forecast, the Directors unanimously adopted the Advocate's forecast in the amount of $1,917,229 as the appropriate amount for Customer Deposits.

V(a)18. ACCRUED INTEREST ON CUSTOMER DEPOSITS

The rules of the Authority require gas utilities to accrue interest on Customer Deposits. This interest is then refunded to the customer along with the security deposit after a specified period when credit worthiness has been demonstrated. The Directors concluded that, because the Interest on Customer Deposits is recognized as an expense in computing Net Operating Income, the accrued interest that has not been paid out should be treated as a deduction to Rate Base.

All of the Parties included $671,344, in Rate Base for their forecast of Accrued Interest on Customer Deposits. However, even though the Company admitted to an error in their forecast of Customer Deposits, none of the Parties made a corresponding adjustment to the Accrued Interest on Customer Deposits.

The Directors, therefore, unanimously approved $686,049 which represents the thirteen (13) month test period average for this account, as the proper forecast for Accrued Interest on Customer Deposits. Therefore, the Directors found after considering the adjustments described previously, that a Rate Base of $92,955,599 is calculated as illustrated in the following table.

COMPARATIVE RATE BASE CALCULATIONS

	Company[17]	Advocate[18]	AVI[19]	Authority
Additions:				
Plant in Service and CWIP	$140,014,935	$140,614,494	$140,014,935	$140,014,935
Acquisition Adjustment	13,355,565	0	0	0
Cash	2,373,422	2,373,422	0	2,373422
Materials and Supplies	453,221	346,273	453,221	453,221
Gas Inventories	5,419,144	6,659,404	5,419,144	5,419,144
Deferred Rate Case Expense	200,668	47,309	200,668	178,834
Prepayments	1,189,348	769,193	1,189,348	1,189,348
Other Accounts Receivable	92,028	138,738	92,028	92,028
Lead/Lag Study	1,736,716	756,038	-396,530	660,923
Total Additions	**$164,835,047**	**151,704,871**	**$146,972,814**	**$150,381,855**
Deductions:				
Accumulated Depreciation	$46,569,377	$46,478,394	$46,569,377	$46,569,377
Accu Amort of Acq Adj.	4,196,041	0	0	0
Accumulated Deferred FIT	5,131,816	5,131,815	5,131,816	5,131,816
Customer Advances	384,855	384,974	384,855	384,855
Contributions in Aid of Const.	1,908,645	1,858,651	1,908,645	1,908,645
Reserve for Uncollectibles	278,723	257,864	278,723	278,723
Other Reserves	549,562	409,201	549,562	549,562
Customer Deposits	3,766,190	1,917,229	3,766,190	1,917,229
Accrued Int on Cust Deposits	671,344	671,344	671,344	686,049
Total Deductions	**$63,456,553**	**$57,109,472**	**$59,260,512**	**$57,426,256**
Rate Base	**$101,378,494**	**$94,595,399**	**$87,712,302**	**$92,955,599**

17 Company Exhibit 5, Schedule 8, Page 1 of 4.
18 Consumer Advocate Pre-Filed Exhibit, Schedule 3.
19 AVI Exhibit MPG-1.

V(b). NET OPERATING INCOME

Net Operating Income ("NOI") represents the earnings of the Company under present rates that are available after all issues of the cost of providing utility service have been considered.

V(b)1. BASE RATE REVENUES

Base Rate Revenues represent the gross margin, gas revenues less gas cost, of the Company at present rates. The Company forecasted their Base Rate Revenues under present rates to be $31,206,762. In their forecast, the Company included the sales volumes for certain Industrial customers at contract rates that were proposed in other dockets, but were subsequently denied. Volumes to these customers should now be priced at the existing Industrial tariff rate. According to the Advocate, making this special contract change will add $606,518 to the Company's base rate forecast, while AVI projects a $635,458 adjustment. The Company did not dispute either of these adjustments in its rebuttal testimony.

As there was no dispute that the adjustments should be made, and because the amounts proposed are close, the Directors unanimously determined that an average of the two adjustments, or $620,988 be adopted. Further, the Directors unanimously approved adding the $620,988 adjustment to the Company's original forecast of $31,206,762 that resulted in a forecast of $31,827,750 for Base Rate Revenues.

V(b)2. OTHER REVENUES

Other Revenues represent revenues that the Company indirectly collects which are not necessarily involved in providing gas service. For example, discounts that are forfeited by the customers who do not promptly pay their bills are included in Other Revenues. The Company included $929,361 in their forecast of Other Revenues. AVI accepted the Company's forecast for this item. The Advocate made two adjustments to the Company's forecast. The Advocate first added $13,862[20] for returned check charges. According to the Advocate, the Company omitted these charges from their forecast. There was no controversy with the Company regarding this issue.

The Advocate's second adjustment to the Company's forecast decreased forfeited discount revenue by $59,657.[21] The Advocate's calculation was based upon a five-year average ratio of forfeited discount revenue to total revenue. Again, there was no dispute on this adjustment with the Company or AVI for this item.

Due to the lack of objections on the record to the adjustments, the Directors unanimously adopted the Advocate's position and included the Advocate's $883,749 amount in Other Revenues. In addition, the Directors also unanimously approved the Advocate's five-year average forfeited discount ratio of 0.006837[22] for the Revenue Conversion Factor.

V(b)3. ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION

Allowance for Funds Used During Construction is not a revenue item, but represents a reduction, or capitalization, of interest expense and equity costs that the Company incurs on projects taking more than thirty (30) days to complete. All of the Parties accepted the Company's forecast of $32,373 for this item. The Directors unanimously concluded, therefore, that the Company's forecast was reasonable and adopted a forecast of $32,373 for this item.

20 Daniel W. McCormac Pre-Filed Direct Testimony, at page 5.
21 Id.
22 Advocate Pre-Filed Exhibit, Schedule 14.

V(b)4. SALARIES AND WAGES

Salaries and Wages represent the direct labor and benefit expenses of the Company's employees in Chattanooga. The Company's calculation was $3,136,136 for Salary and Wage Expense. AVI accepted the Company's forecast for Salary and Wages. The Advocate forecasted $3,084,307 in Salary and Wage Expense, which was $51,829 less than the Company's forecast. There is no mention in the Advocate's testimony of the cause for this difference. Because the record fails to reflect explanations for the difference in the Advocate's calculations, the Directors unanimously accepted the Company's forecast of $3,136,136 for Salary and Wage Expense.

V(b)5. DISTRIBUTION EXPENSE

Distribution Expense relates to costs incurred in operating and maintaining the Company's gas distribution system. Some examples of items that would be classified as Distribution Expense would include expenses relating to dispatching, metering, and maintenance of the Company's mains and service lines. Because these types of expenses cannot be easily priced individually, the Parties agree that they must rely on a growth factor to forecast distribution expenses.

The growth factor contains an inflation component and a customer growth component that produces a measure of the expected annual growth. The annual growth factor is then compounded for the number of months to the end of the attrition period to produce a total growth factor. The test period level of expenses is then multiplied by the total growth factor to give the attrition period forecast expense.

V(b)5a. CUSTOMER GROWTH RATE

The Company computed a compound customer growth rate of 8.95 for twenty-four (24) months that produces a 4.38 percent annual growth. The Company's computation is slightly below the Advocate's proffered annual customer growth rate of 4.65 percent. The record reflects that the

Advocate made no adjustment to the Company's revenue calculation for customer growth. Since the record appeared to reflect that the Advocate accepted the Company's customer growth calculation for revenues, the Directors unanimously found that it was consistent to accept the Company's customer growth calculation for expenses. Therefore, on this sub-item, the Directors unanimously adopted the Company's annual customer growth calculation of 4.38 percent.

V(b)5b. CUSTOMER GROWTH ADJUSTMENT

The Advocate argued that 50 percent of the annual customer rate should be considered based on this Authority's historical practice of adjusting customer growth by 50 percent in natural gas company rate cases. The Company objected to this adjustment in their rebuttal testimony. The Directors determined that, historically, not all expenses increased over time due to customer growth. While some expenses such as vehicle maintenance expenses increase proportionately with customer growth, others such as office maintenance expenses have no correlation with customer growth. Therefore, on this sub-item, the Directors unanimously adopted the 50 percent adjustment proposed by the Advocate.

V(b)5c. COMPOUND INFLATION RATE

The Company computed a compound inflation rate of 6.67 percent for twenty-four (24) months as measured by the Consumer Price Index. This computation produced a 3.15 percent annual inflation rate. The Advocate used 2.19 percent as its annual inflation rate as measured by the gross domestic product ("GDP") deflator. At the Hearing, the Company witness stated that either index could be used as a measure of inflation. This Authority has recognized that the GDP index is a more appropriate measure for use in rate cases. Therefore, the Directors unanimously adopted an annual GDP factor of 2.36 percent based on the blue-chip indicator's publication as stated on page 13 of Mr. Buckner's testimony from the Advocate's Office.[23]

V(b)5d. COMPOUND GROWTH FACTOR

Considering all of the sub-items included in distribution expense, a compound growth factor of 9.31 percent is produced as shown below.

GROWTH FACTOR CALCULATIONS

	Company[24]	Consumer Advocate[25]	Authority[26]
1. Annual Customer Growth Rate	4.38%	4.65%	4.38%
2. Percentage Allowed	100%	50%	50%
3. **Net Annual Customer Growth Rate**	**4.38%**	**2.33%**	**2.19%**
4. Annual Inflation Rate	3.15%	2.19%	2.36%
5. **Total Annual Growth Factor**	**7.53%**	**4.52%**	**4.55%**
6. Months to Compound	24	19	24
7. **Total Compound Growth Factor**	**15.62%**	**7.25%**	**9.31%**

The Directors adopted 9.31 percent as the proper factor to grow expenses in this matter that are not specifically priced out. By applying the 9.31 percent growth factor to the Company's September 30, 1996, adjusted test period distribution expenses of $848,394, the growth factor produces an attrition period balance of $927,379. The Directors found, therefore, that $927,379 was a proper level of distribution expense.

---

23 R. Terry Buckner Pre-Filed Direct Testimony at page 13.

24 Gerald A. Hinesley Pre-Filed Direct, at page 4.

25 The Advocate's total compound growth factor is 7.25 percent according to R. Terry Buckner Pre-Filed Direct Testimony, at page 13. His testimony describes this growth factor as compounded for a 19 month period (May 31, 1997 through September 30, 1998), it is, however, a 16 month period.

26 The annual customer growth rate of 4.38 percent is the rate used by the Company.

V(b)6. STORAGE EXPENSE

Storage Expense relates to costs, other than labor and gas, incurred in operating and maintaining the Company's gas storage assets. The Company owns a liquefied natural gas (LNG) facility that is included in the Rate Base calculation under Plant in Service. The LNG facility cools natural gas to a very low temperature until it is converted into a liquid state. The liquefied gas is then stored until needed, at which time it is heated and vaporized back into a gaseous state. This process makes it efficient to store large quantities of natural gas in a relatively small containment area. The cost of operating and maintaining the LNG facility is accounted for as Storage Expense.

Chattanooga Gas and the Advocate forecasted Storage Expenses of $987,610 and $813,689, respectively. AVI accepted the Company's forecast for Storage Expense in their calculation of NOI. The Directors concluded that the difference between the Company and Advocate's calculation of Storage Expense resulted from the use of their different growth factors. After reducing the Company's test year Storage Expense for $34,000[27] in certain non-recurring items, the Directors unanimously concluded that applying the adopted growth factor of 9.31 percent to the September 30, 1996, adjusted test period balance of $820,191, produced an attrition amount of $896,551. The Directors, therefore, approved $896,551 as the proper level of Storage Expense.

V(b)7. CUSTOMER ACCOUNTS EXPENSE

Customer Accounts Expense relates to costs incurred, excluding labor, in billing and collecting amounts owed by Company customers. Some examples of items that would be classified as Customer Accounts Expense would include meter reading, cashiers, and collection expenses.

---

27 See Authority clarification request #78 with response filed by Chattanooga Gas and copies to all Parties filed August 13, 1997. This Adjustment was not taken into account by either the Company or the Advocate.

The Directors unanimously concluded that applying the adopted growth factor of 9.31 percent to the September 30, 1996, adjusted test period balance of $88,951 produced an attrition period balance in this category of $97,232. The Directors, therefore, unanimously approved a balance of $97,232 as the appropriate forecast for Customer Accounts Expense.

V(b)8. UNCOLLECTIBLE EXPENSE

Uncollectible expenses recognize the Company's annual provision for amounts due from customers that will not be collected. On October 1, 1996, the Company changed the methodology by which it recognizes uncollectible expenses to one that estimated the expense based on actual net write-offs in the uncollectible account. The Company's new methodology would not have been recognized in this rate proceeding because the test period ended September 30, 1996. Therefore, the Company chose to update their test period to the twelve (12) months that ended February 28, 1997, for Uncollectible Expense, and use the September 30, 1996, test period for all other items. [28] By updating the test period to February 28, 1997, the Company recognized $385,019 in their forecast for Uncollectible Expense.

Both AVI and the Advocate disagreed with the Company's methodology. The Advocate argued that the Company's calculation was more than double the historical amounts for the previous six (6) fiscal years. [29] The Advocate also argued that the Company did not present any evidence that shows that the expense will continue at this rate. The Advocate chose to include only $165,968 in its forecast as Uncollectible Expense. This amount represents the average of the Company's actual net write-offs for the last seven (7) years and eight (8) months. AVI also opposed the Company's proposed forecast of Uncollectible Expense because it is not based on test

---

[28] *In re: Petition of Chattanooga Gas Company to Place Into Effect a Revised Natural Gas Tariff, Hearing on the Merits before the Tennessee Regulatory Authority, Transcript of Proceedings*, February 10, 1998, Volume 2B, at page 177.

[29] R. Terry Buckner Pre-Filed Direct Testimony, at page 12.

year data as previously described.[30] AVI proposed instead to use the 1996 actual Uncollectible Expense of $199,019 in its forecast.

The Directors concluded that it would not be appropriate to recognize an eight (8) month period in the development of any annual average as the Advocate has done. Rather, the Directors unanimously adopted the use of a seven (7) year average of the net write-offs from 1990 to 1996 as the proper forecast of Uncollectible Expense. This produces $138,006 in forecasted Uncollectible Expense. The Directors concluded that this methodology recognizes that the aged delinquent accounts should be properly recognized as a recurring event over a longer period of time. This adoption also changes the Uncollectible Expense component of the Revenue Conversion Factor to 0.005368.[31]

V(b)9. SALES PROMOTION EXPENSE

Sales Promotion Expense relates to costs incurred, excluding labor, to promote or retain the use of utility services by present or prospective customers. Some examples of items that would be classified as Sales Promotion Expense would include demonstrating expenses, selling expenses, and advertising expenses.

The Company forecasted Sales Promotion Expense of $455,531. The Company's forecast was made by taking the test period balance of Sales Promotion Expense in the amount of $367,929[32] and then eliminating labor expenses. The balance was then increased by the Company's compound inflation and customer growth factor. This forecast was adopted by AVI in their calculation of NOI.

---

30 Michael Gorman Pre-Filed Direct Testimony, at page 21.

31 Uncollectible Expense of $138,006 / Test Year Residential and Commercial Revenues of $25,707,838 = 0.005368.

32 Company Workpapers O&M-6 and O&M-7.

The Advocate recommended a forecast based on a standard criterion of .5 percent of revenues. Further, the Advocate stated that the Tennessee Public Service Commission found the .5 percent factor to be consistent with the rule on sales promotional expense, and referred to this factor as a policy. The Directors stated emphatically that neither the Authority nor the Tennessee Public Service Commission ever adopted a policy of .5 percent for the expense of promotions. The Directors found that in the 1984 Application of Nashville Gas Company, a Division of Piedmont Natural Gas Company, Inc., for an Adjustment of its Rates and Charges, a .5 percent factor was applied to nonpayroll cost only. The .5 percent factor was unique to that case. The Directors clearly and unequivocally stated that there is no policy for this .5 percent factor as the Advocate asserted. Further, the Court of Appeals dispels the Advocate's argument on this issue.[33] Applying

---

[33] The Court of Appeals held:

> This is an issue on which the briefs of the principal parties seem to be speaking different languages. The following explanation is the best we can glean from the record. In 1984 the Public Service Commission adopted a rule that disallowed as a recoverable expense by a utility any "promotional or political advertising." The prohibition covered advertising for the purpose of encouraging any person to select or use gas service or additional gas service. It did not cover (among other things) advertising informing customers how to conserve energy or to reduce peak demand for gas, or advertising promoting the use of energy efficient appliances. See former Rule 1220-4-5-.45, Tenn. Regis.
>
> In a 1985 proceeding involving a rate increase application by NGC, the Commission deviated from the rule and allowed advertising expenses up to .5 percent of revenues. In March of 1996 the Commission repealed 1220A-5-.45 and proposed a new rule that would allow a utility to recover "all prudently incurred expenditures for advertising." Apparently the rule had not made it completely through the adoption procedure when the TRA heard this case below. Nevertheless, based on proof of $1,486,000 in external advertising expenses, $800,000 in marketing personnel payroll and $300,000 in miscellaneous sales expenses, the TRA allowed the recovery of all but approximately half of the external advertising expenses. The CAD urged disallowance of all the related expenses except approximately $647,000 and NGC claims that the TRA erred in reducing the external operating expenses because there was no proof that they were imprudently incurred.
>
> We think the TRA was justified in its conclusion on this issue. Based on the testimony in the record that the advertising expenses were incurred to meet competition, to add new customers on existing mains, and to get existing customers to use more gas, the TRA concluded that the rate payers benefited from at least part of the external advertising.

Consumer Advocate Division v. Tennessee Regulatory Authority, No. 01-A-01-9708-BC-00931, op. at 8, 9 (Tenn. Ct. App., July 1, 1998).

the 9.31 percent growth factor discussed previously to the test period balance produces a forecast of $430,670. The Directors, therefore, unanimously concluded that $430,670 was an appropriate forecast for promotion expense, and adopted the sales promotion expense forecast of the Company.

V(b)10. ADMINISTRATIVE AND GENERAL EXPENSE

Administrative & General Expense ("A&G") relates to costs incurred, excluding payroll, in operating the utility that are not directly chargeable to a particular function. Some examples of items that would be classified as A&G Expense would include audit and pension expense. The Company calculated $2,448,665 for A&G Expense while the Advocate only included $2,115,562 in their forecast. AVI accepted the Company's forecast in their calculation of NOI. The table below highlights the differences between the Parties for A&G Expense.

DETAIL OF A&G EXPENSE

	Company and AVI	Consumer Advocate[34]	Authority
Growth Factor	$1,000,969	$928,506	$787,373
Rate Case Expense	168,144	64,334	119,221
Other Items	1,279,552	1,122,722	1,279,552
Total	**$2,448,665**	**$2,115,562**	**$2,186,146**

Applying the growth factor of 9.31 percent[35] to the September 30, 1996, adjusted test period balance of $720,312 produces an attrition amount of $787,373. The Directors, therefore, unanimously adopted $787,373 as the appropriate level of A&G Expense relating to customer growth and inflation.

[34] The Advocate's A&G Expenses related to growth based on the test period is the amount increased by the Advocate's growth factor. However, the difference in the calculation was not able to be reconciled with the Advocate's case.

[35] See Section V(b)5e.

The Company used their growth factor to determine the attrition year level of Rate Case Expense. The Company took the test period expense of $145,428 and increased it by 15.62 percent[36] to arrive at an attrition-year-rate-case expense of $168,144. The Advocate estimated the cost to complete the current case to be $144,500. [37] The Advocate took this estimated cost and amortized it over three years to give an annual amortization of $48,167. The Advocate then added one year of additional amortization or $16,167 from the Company's 1995 rate case to obtain their total Rate Case Expense of $64,334.

The Directors found that these Rate Case Expense calculations should have been related to the Deferred Rate Case Expense. The Directors concluded that the estimated cost of this case should be added to the test period Deferred Rate Case Expense with the total amortized over a new three year period. This calculation produced Rate Case Expense of $119,221. The Directors, therefore, adopted $119,221 as the proper level of A&G Expense relating to Rate Case Expense.

Finally, the Advocate reduced the Company's forecast of the remaining items of A&G Expense from $1,279,552 to $1,122,722. However, the Directors found that the Advocate failed to document its reasoning for this reduction in its testimony or through cross-examination at the Hearing. Therefore, the Directors unanimously adopted $1,279,552 as the appropriate level of A&G Expense relating to "other items" of A&G Expense.

The total for all three components of A&G Expense equals $2,186,146. Therefore, the Directors unanimously approved this amount as the proper level of A&G Expense.

---

36 Gerald A. Hinesley Pre-Filed Direct Testimony, at page 4, and Company Workpaper O&M-1.

37 R. Terry Buckner Pre-Filed Direct Testimony, at page 14.

V(b)11. CORPORATE ALLOCATIONS

During the 1996 fiscal year, corporate shared services were allocated based on a percentage of approximately 3.8 percent[38] of AGL's customers in Tennessee and Georgia. Beginning in October 1996, the Company changed its allocation methodology. The new overhead allocation methodology uses numerous allocation percentages, depending on the type of service rendered. Allocations can be based on the number of full-time employees, number of users, hours used, number of customers or any combination of these drivers. The allocation percentages are updated monthly using a computer allocation model.

James Kissel, a Senior Manager with Deloitte & Touche Consulting Group testifying for Chattanooga Gas, stated that the purpose of his testimony was to "demonstrate that the methodology is rational, fair and equitable."[39] He also stated that his testimony "addresses only the approach to allocating costs and not the actual cost levels of the various business functions."[40] In his Pre-filed testimony, he goes into great detail describing the various services that are allocated and the rationale for selecting the appropriate drivers to allocate these services. Using a "typical year," he stated that Chattanooga Gas would receive a composite allocation of 3.7 percent.[41] This was reiterated where he stated that, ". . . the new methodology allocates 3.7 percent of the central service costs to Chattanooga Gas Company."[42] He detailed, as did Mr. Thompson, President of Chattanooga Gas Company,[43] that there was an increase in cost allocation to Chattanooga Gas due to the inclusion of costs not formerly allocated to Chattanooga Gas.[44] Mr. Kissell's estimate of the

---

38 James E. Kissel, Pre-Filed Direct Testimony, at page 15.
39 Id., at page 2.
40 James E. Kissell Pre-Filed Direct Testimony, at page 2.
41 Id, at page 11.
42 Id, at page 13.
43 Harrison F. Thompson Pre-Filed Direct Testimony,at page 5
44 James E. Kissell Pre-Filed Direct Testimony, at pages 11-13.

increase to Chattanooga Gas, when costs were fully allocated, was approximately \$2.3 million. [45] Mr. Kissell also responded that allocating costs on a single driver, such as customers, does not accurately reflect the amount of resources consumed by the individual business organization. [46]

The Advocate argued that there were several problems with accepting the Company's new methodology for allocating common costs. First, because the methodology is excessively complex, it would be extremely difficult for a regulator to verify that costs are being accurately allocated to Tennessee. Secondly, because there are multifactors involved, the potential exists for AGL to manipulate costs between jurisdictions, thereby recovering over or under 100 percent of its common costs. A company's "external auditors rarely, if ever, certify the accuracy of charges between jurisdictions, but usually examine only the Company's operations in total." [47] Instead, the Advocate recommends that AGL allocate its common costs using a single allocation component based upon the number of customers in Georgia and Tennessee. [48] The Advocate also argued that this methodology would not only leave a cleaner audit trail, but also allow regulators to verify the accuracy of the charges allocated to Tennessee and Georgia customers.

In addition to disagreeing with the Company's allocation methodology, the Advocate also disagreed with the Company's allocated expenses of \$5.227 million. The Company annualized their fiscal year-to-date base costs. These annualized costs were then allocated to Chattanooga Gas using the new allocation model.

The Advocate also annualized the base costs to be allocated, and then used a single allocation percentage of 3.73 percent based on the number of Tennessee customers. The Advocate argued that the Company claimed that the new methodology allocates 3.7 percent of the central

---

45 James E. Kissell Pre-Filed Direct Testimony, at page 11.
46 Id., at page 15.
47 R. Terry Buckner Pre-Filed Direct Testimony, at page 8.
48 Id., at page 5.

service costs, while the actual composite percentage allocated to Chattanooga Gas in the Company's case is 5.13 percent. These different approaches account for $1.249 million of the difference between the Advocate and the Company's case for this item. The Advocate next indicated that the difference in the rate of return on allocated net assets accounts for an additional $0.155 million. Finally, the Advocate argued an additional difference of $0.093 million occurred because the Company did not allocate any of its corporate office costs to non-utility operations. As a result of its analysis, the Advocate recommended an inclusion of $3.730 million in Corporate Allocated Expenses.

AVI stated that the Company did not provide support for the allocation factors used to forecast its estimated shared service allocation to Chattanooga Gas.[49] AVI also argued that this item represents the largest single adjustment to the test year cost of service, and that the Company should be compelled to provide support to show the complete derivation of all elements used to establish this reallocation. Absent a clear demonstration of support for the Company's calculations, AVI asked that the reallocation be rejected.[50]

While Company witness James Kissel testified that the new methodology is the "most fair, equitable and rational approach,"[51] his colleague at Deloitte & Touche, Gregory E. Aliff, co-author of ACCOUNTING FOR PUBLIC UTILITIES, stated that:

> For a utility, the basic goals of intercompany cost allocation methodologies are to:
> (1) prevent or limit, to the extent possible, any cross-subsidization of one activity or entity by another; and
> (2) minimize the time and expense necessary to reflect and audit the transactions.
>
> The second goal of a cost allocation system is to minimize the time and expense necessary to record and audit transactions. This goal is important because the system for

49 Michael Gorman Pre-Filed Direct Testimony, at page 22.
50 Id., at page 22.
51 James E. Kissell Pre-Filed Direct Testimony, at page 15.

allocating shared costs must be understandable and workable. The personnel responsible for the accounting and reporting of the costs must be able to apply the system properly if it is to produce the desired results. In addition, an overly detailed or complex system could increase business costs and diminish any cost benefits of the shared activities. Thus, it is possible for the system to impact the economics of the business transaction.

The time and expense necessary to audit the transactions is also an important consideration. Similar to accounting and reporting for these transactions, auditing intercompany transactions should not impose an extreme cost burden or be so time consuming as to prevent effective system testing. These requirements would most likely result in resistance to or nonacceptance of the system by regulators and others." [52]

The Directors' review of the record in this matter compelled them to concur with the Advocate in concluding that the complexity of the allocation methodology implemented by Chattanooga Gas makes it difficult to accept. The Directors made no judgments regarding the accuracy of AGL's allocation methodology, but did conclude that regulation requires a more audit-friendly environment. The Directors found further that the burden for determining fairness, equity, and accuracy of costs imposed on Tennessee ratepayers should not shift to the Authority either by design or by chance. While the Directors stated that they fully endorse systems that more accurately ascribe costs to cost causes, they determined that an allocation system must minimize the time and expense necessary to reflect and audit transactions. Therefore, the Directors unanimously concluded that the use of a single allocation formula based on customers in Tennessee and Georgia is the most appropriate method of allocation of common cost at the present time. Additionally, the Directors found that the Advocate correctly asserted that the Company did not allocate any of its corporate office costs to nonutility operations. Therefore, the Directors unanimously adopted the Advocate's forecast of $3.730 million in Corporate Allocated Expenses. Additionally, the Directors unanimously adopted the Advocate's recommendation for a single allocation factor, based on

[52] R.L. HAHNE AND G.E. ALIFF, ACCOUNTING FOR PUBLIC UTILITIES, Matthew Bender, Accounting Series, §19.02, page 19-4, 19-5.

V(b). <u>NET OPERATING INCOME</u>

Net Operating Income ("NOI") represents the earnings of the Company under present rates that are available after all issues of the cost of providing utility service have been considered.

V(b)1. BASE RATE REVENUES

Base Rate Revenues represent the gross margin, gas revenues less gas cost, of the Company at present rates. The Company forecasted their Base Rate Revenues under present rates to be $31,206,762. In their forecast, the Company included the sales volumes for certain Industrial customers at contract rates that were proposed in other dockets, but were subsequently denied. Volumes to these customers should now be priced at the existing Industrial tariff rate. According to the Advocate, making this special contract change will add $606,518 to the Company's base rate forecast, while AVI projects a $635,458 adjustment. The Company did not dispute either of these adjustments in its rebuttal testimony.

As there was no dispute that the adjustments should be made, and because the amounts proposed are close, the Directors unanimously determined that an average of the two adjustments, or $620,988 be adopted. Further, the Directors unanimously approved adding the $620,988 adjustment to the Company's original forecast of $31,206,762 that resulted in a forecast of $31,827,750 for Base Rate Revenues.

V(b)2. OTHER REVENUES

Other Revenues represent revenues that the Company indirectly collects which are not necessarily involved in providing gas service. For example, discounts that are forfeited by the customers who do not promptly pay their bills are included in Other Revenues. The Company included $929,361 in their forecast of Other Revenues. AVI accepted the Company's forecast for this item. The Advocate made two adjustments to the Company's forecast. The Advocate first added $13,862[20] for returned check charges. According to the Advocate, the Company omitted these charges from their forecast. There was no controversy with the Company regarding this issue.

The Advocate's second adjustment to the Company's forecast decreased forfeited discount revenue by $59,657.[21] The Advocate's calculation was based upon a five-year average ratio of forfeited discount revenue to total revenue. Again, there was no dispute on this adjustment with the Company or AVI for this item.

Due to the lack of objections on the record to the adjustments, the Directors unanimously adopted the Advocate's position and included the Advocate's $883,749 amount in Other Revenues. In addition, the Directors also unanimously approved the Advocate's five-year average forfeited discount ratio of 0.006837[22] for the Revenue Conversion Factor.

V(b)3. ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION

Allowance for Funds Used During Construction is not a revenue item, but represents a reduction, or capitalization, of interest expense and equity costs that the Company incurs on projects taking more than thirty (30) days to complete. All of the Parties accepted the Company's forecast of $32,373 for this item. The Directors unanimously concluded, therefore, that the Company's forecast was reasonable and adopted a forecast of $32,373 for this item.

---

20 Daniel W. McCormac Pre-Filed Direct Testimony, at page 5.
21 Id.
22 Advocate Pre-Filed Exhibit, Schedule 14.

V(b)4. SALARIES AND WAGES

Salaries and Wages represent the direct labor and benefit expenses of the Company's employees in Chattanooga. The Company's calculation was $3,136,136 for Salary and Wage Expense. AVI accepted the Company's forecast for Salary and Wages. The Advocate forecasted $3,084,307 in Salary and Wage Expense, which was $51,829 less than the Company's forecast. There is no mention in the Advocate's testimony of the cause for this difference. Because the record fails to reflect explanations for the difference in the Advocate's calculations, the Directors unanimously accepted the Company's forecast of $3,136,136 for Salary and Wage Expense.

V(b)5. DISTRIBUTION EXPENSE

Distribution Expense relates to costs incurred in operating and maintaining the Company's gas distribution system. Some examples of items that would be classified as Distribution Expense would include expenses relating to dispatching, metering, and maintenance of the Company's mains and service lines. Because these types of expenses cannot be easily priced individually, the Parties agree that they must rely on a growth factor to forecast distribution expenses.

The growth factor contains an inflation component and a customer growth component that produces a measure of the expected annual growth. The annual growth factor is then compounded for the number of months to the end of the attrition period to produce a total growth factor. The test period level of expenses is then multiplied by the total growth factor to give the attrition period forecast expense.

V(b)5a. CUSTOMER GROWTH RATE

The Company computed a compound customer growth rate of 8.95 for twenty-four (24) months that produces a 4.38 percent annual growth. The Company's computation is slightly below the Advocate's proffered annual customer growth rate of 4.65 percent. The record reflects that the

Advocate made no adjustment to the Company's revenue calculation for customer growth. Since the record appeared to reflect that the Advocate accepted the Company's customer growth calculation for revenues, the Directors unanimously found that it was consistent to accept the Company's customer growth calculation for expenses. Therefore, on this sub-item, the Directors unanimously adopted the Company's annual customer growth calculation of 4.38 percent.

V(b)5b. CUSTOMER GROWTH ADJUSTMENT

The Advocate argued that 50 percent of the annual customer rate should be considered based on this Authority's historical practice of adjusting customer growth by 50 percent in natural gas company rate cases. The Company objected to this adjustment in their rebuttal testimony. The Directors determined that, historically, not all expenses increased over time due to customer growth. While some expenses such as vehicle maintenance expenses increase proportionately with customer growth, others such as office maintenance expenses have no correlation with customer growth. Therefore, on this sub-item, the Directors unanimously adopted the 50 percent adjustment proposed by the Advocate.

V(b)5c. COMPOUND INFLATION RATE

The Company computed a compound inflation rate of 6.67 percent for twenty-four (24) months as measured by the Consumer Price Index. This computation produced a 3.15 percent annual inflation rate. The Advocate used 2.19 percent as its annual inflation rate as measured by the gross domestic product ("GDP") deflator. At the Hearing, the Company witness stated that either index could be used as a measure of inflation. This Authority has recognized that the GDP index is a more appropriate measure for use in rate cases. Therefore, the Directors unanimously adopted an annual GDP factor of 2.36 percent based on the blue-chip indicator's publication as stated on page 13 of Mr. Buckner's testimony from the Advocate's Office. [23]

V(b)5d. COMPOUND GROWTH FACTOR

Considering all of the sub-items included in distribution expense, a compound growth factor of 9.31 percent is produced as shown below.

GROWTH FACTOR CALCULATIONS

	Company[24]	Consumer Advocate[25]	Authority[26]
1. Annual Customer Growth Rate	4.38%	4.65%	4.38%
2. Percentage Allowed	100%	50%	50%
3. Net Annual Customer Growth Rate	**4.38%**	**2.33%**	**2.19%**
4. Annual Inflation Rate	3.15%	2.19%	2.36%
5. Total Annual Growth Factor	**7.53%**	**4.52%**	**4.55%**
6. Months to Compound	24	19	24
7. Total Compound Growth Factor	**15.62%**	**7.25%**	**9.31%**

The Directors adopted 9.31 percent as the proper factor to grow expenses in this matter that are not specifically priced out. By applying the 9.31 percent growth factor to the Company's September 30, 1996, adjusted test period distribution expenses of $848,394, the growth factor produces an attrition period balance of $927,379. The Directors found, therefore, that $927,379 was a proper level of distribution expense.

---

23 R. Terry Buckner Pre-Filed Direct Testimony at page 13.

24 Gerald A. Hinesley Pre-Filed Direct, at page 4.

25 The Advocate's total compound growth factor is 7.25 percent according to R. Terry Buckner Pre-Filed Direct Testimony, at page 13. His testimony describes this growth factor as compounded for a 19 month period (May 31, 1997 through September 30, 1998), it is, however, a 16 month period.

26 The annual customer growth rate of 4.38 percent is the rate used by the Company.

V(b)6. STORAGE EXPENSE

Storage Expense relates to costs, other than labor and gas, incurred in operating and maintaining the Company's gas storage assets. The Company owns a liquefied natural gas (LNG) facility that is included in the Rate Base calculation under Plant in Service. The LNG facility cools natural gas to a very low temperature until it is converted into a liquid state. The liquefied gas is then stored until needed, at which time it is heated and vaporized back into a gaseous state. This process makes it efficient to store large quantities of natural gas in a relatively small containment area. The cost of operating and maintaining the LNG facility is accounted for as Storage Expense.

Chattanooga Gas and the Advocate forecasted Storage Expenses of $987,610 and $813,689, respectively. AVI accepted the Company's forecast for Storage Expense in their calculation of NOI. The Directors concluded that the difference between the Company and Advocate's calculation of Storage Expense resulted from the use of their different growth factors. After reducing the Company's test year Storage Expense for $34,000[27] in certain non-recurring items, the Directors unanimously concluded that applying the adopted growth factor of 9.31 percent to the September 30, 1996, adjusted test period balance of $820,191, produced an attrition amount of $896,551. The Directors, therefore, approved $896,551 as the proper level of Storage Expense.

V(b)7. CUSTOMER ACCOUNTS EXPENSE

Customer Accounts Expense relates to costs incurred, excluding labor, in billing and collecting amounts owed by Company customers. Some examples of items that would be classified as Customer Accounts Expense would include meter reading, cashiers, and collection expenses.

---

[27] See Authority clarification request #78 with response filed by Chattanooga Gas and copies to all Parties filed August 13, 1997. This Adjustment was not taken into account by either the Company or the Advocate.

The Directors unanimously concluded that applying the adopted growth factor of 9.31 percent to the September 30, 1996, adjusted test period balance of $88,951 produced an attrition period balance in this category of $97,232. The Directors, therefore, unanimously approved a balance of $97,232 as the appropriate forecast for Customer Accounts Expense.

V(b)8. UNCOLLECTIBLE EXPENSE

Uncollectible expenses recognize the Company's annual provision for amounts due from customers that will not be collected. On October 1, 1996, the Company changed the methodology by which it recognizes uncollectible expenses to one that estimated the expense based on actual net write-offs in the uncollectible account. The Company's new methodology would not have been recognized in this rate proceeding because the test period ended September 30, 1996. Therefore, the Company chose to update their test period to the twelve (12) months that ended February 28, 1997, for Uncollectible Expense, and use the September 30, 1996, test period for all other items. [28] By updating the test period to February 28, 1997, the Company recognized $385,019 in their forecast for Uncollectible Expense.

Both AVI and the Advocate disagreed with the Company's methodology. The Advocate argued that the Company's calculation was more than double the historical amounts for the previous six (6) fiscal years. [29] The Advocate also argued that the Company did not present any evidence that shows that the expense will continue at this rate. The Advocate chose to include only $165,968 in its forecast as Uncollectible Expense. This amount represents the average of the Company's actual net write-offs for the last seven (7) years and eight (8) months. AVI also opposed the Company's proposed forecast of Uncollectible Expense because it is not based on test

---

[28] *In re: Petition of Chattanooga Gas Company to Place Into Effect a Revised Natural Gas Tariff, Hearing on the Merits before the Tennessee Regulatory Authority, Transcript of Proceedings*, February 10, 1998, Volume 2B, at page 177.

[29] R. Terry Buckner Pre-Filed Direct Testimony, at page 12.

year data as previously described.[30] AVI proposed instead to use the 1996 actual Uncollectible Expense of $199,019 in its forecast.

The Directors concluded that it would not be appropriate to recognize an eight (8) month period in the development of any annual average as the Advocate has done. Rather, the Directors unanimously adopted the use of a seven (7) year average of the net write-offs from 1990 to 1996 as the proper forecast of Uncollectible Expense. This produces $138,006 in forecasted Uncollectible Expense. The Directors concluded that this methodology recognizes that the aged delinquent accounts should be properly recognized as a recurring event over a longer period of time. This adoption also changes the Uncollectible Expense component of the Revenue Conversion Factor to 0.005368.[31]

V(b)9. SALES PROMOTION EXPENSE

Sales Promotion Expense relates to costs incurred, excluding labor, to promote or retain the use of utility services by present or prospective customers. Some examples of items that would be classified as Sales Promotion Expense would include demonstrating expenses, selling expenses, and advertising expenses.

The Company forecasted Sales Promotion Expense of $455,531. The Company's forecast was made by taking the test period balance of Sales Promotion Expense in the amount of $367,929[32] and then eliminating labor expenses. The balance was then increased by the Company's compound inflation and customer growth factor. This forecast was adopted by AVI in their calculation of NOI.

---

30 Michael Gorman Pre-Filed Direct Testimony, at page 21.

31 Uncollectible Expense of $138,006 / Test Year Residential and Commercial Revenues of $25,707,838 = 0.005368.

32 Company Workpapers O&M-6 and O&M-7.

The Advocate recommended a forecast based on a standard criterion of .5 percent of revenues. Further, the Advocate stated that the Tennessee Public Service Commission found the .5 percent factor to be consistent with the rule on sales promotional expense, and referred to this factor as a policy. The Directors stated emphatically that neither the Authority nor the Tennessee Public Service Commission ever adopted a policy of .5 percent for the expense of promotions. The Directors found that in the 1984 Application of Nashville Gas Company, a Division of Piedmont Natural Gas Company, Inc., for an Adjustment of its Rates and Charges, a .5 percent factor was applied to nonpayroll cost only. The .5 percent factor was unique to that case. The Directors clearly and unequivocally stated that there is no policy for this .5 percent factor as the Advocate asserted. Further, the Court of Appeals dispels the Advocate's argument on this issue.[33] Applying

---

33 The Court of Appeals held:

> This is an issue on which the briefs of the principal parties seem to be speaking different languages. The following explanation is the best we can glean from the record. In 1984 the Public Service Commission adopted a rule that disallowed as a recoverable expense by a utility any "promotional or political advertising." The prohibition covered advertising for the purpose of encouraging any person to select or use gas service or additional gas service. It did not cover (among other things) advertising informing customers how to conserve energy or to reduce peak demand for gas, or advertising promoting the use of energy efficient appliances. See former Rule 1220-4-5-.45, Tenn. Regis.
>
> In a 1985 proceeding involving a rate increase application by NGC, the Commission deviated from the rule and allowed advertising expenses up to .5 percent of revenues. In March of 1996 the Commission repealed 1220A-5-.45 and proposed a new rule that would allow a utility to recover "all prudently incurred expenditures for advertising." Apparently the rule had not made it completely through the adoption procedure when the TRA heard this case below. Nevertheless, based on proof of $1,486,000 in external advertising expenses, $800,000 in marketing personnel payroll and $300,000 in miscellaneous sales expenses, the TRA allowed the recovery of all but approximately half of the external advertising expenses. The CAD urged disallowance of all the related expenses except approximately $647,000 and NGC claims that the TRA erred in reducing the external operating expenses because there was no proof that they were imprudently incurred.
>
> We think the TRA was justified in its conclusion on this issue. Based on the testimony in the record that the advertising expenses were incurred to meet competition, to add new customers on existing mains, and to get existing customers to use more gas, the TRA concluded that the rate payers benefited from at least part of the external advertising.

Consumer Advocate Division v. Tennessee Regulatory Authority, No. 01-A-01-9708-BC-00931, op. at 8, 9 (Tenn. Ct. App., July 1, 1998).

the 9.31 percent growth factor discussed previously to the test period balance produces a forecast of $430,670. The Directors, therefore, unanimously concluded that $430,670 was an appropriate forecast for promotion expense, and adopted the sales promotion expense forecast of the Company.

V(b)10. ADMINISTRATIVE AND GENERAL EXPENSE

Administrative & General Expense ("A&G") relates to costs incurred, excluding payroll, in operating the utility that are not directly chargeable to a particular function. Some examples of items that would be classified as A&G Expense would include audit and pension expense. The Company calculated $2,448,665 for A&G Expense while the Advocate only included $2,115,562 in their forecast. AVI accepted the Company's forecast in their calculation of NOI. The table below highlights the differences between the Parties for A&G Expense.

DETAIL OF A&G EXPENSE

	Company and AVI	Consumer Advocate[34]	Authority
Growth Factor	$1,000,969	$928,506	$787,373
Rate Case Expense	168,144	64,334	119,221
Other Items	1,279,552	1,122,722	1,279,552
Total	**$2,448,665**	**$2,115,562**	**$2,186,146**

Applying the growth factor of 9.31 percent[35] to the September 30, 1996, adjusted test period balance of $720,312 produces an attrition amount of $787,373. The Directors, therefore, unanimously adopted $787,373 as the appropriate level of A&G Expense relating to customer growth and inflation.

[34] The Advocate's A&G Expenses related to growth based on the test period is the amount increased by the Advocate's growth factor. However, the difference in the calculation was not able to be reconciled with the Advocate's case.

[35] See Section V(b)5e.

The Company used their growth factor to determine the attrition year level of Rate Case Expense. The Company took the test period expense of $145,428 and increased it by 15.62 percent[36] to arrive at an attrition-year-rate-case expense of $168,144. The Advocate estimated the cost to complete the current case to be $144,500. [37] The Advocate took this estimated cost and amortized it over three years to give an annual amortization of $48,167. The Advocate then added one year of additional amortization or $16,167 from the Company's 1995 rate case to obtain their total Rate Case Expense of $64,334.

The Directors found that these Rate Case Expense calculations should have been related to the Deferred Rate Case Expense. The Directors concluded that the estimated cost of this case should be added to the test period Deferred Rate Case Expense with the total amortized over a new three year period. This calculation produced Rate Case Expense of $119,221. The Directors, therefore, adopted $119,221 as the proper level of A&G Expense relating to Rate Case Expense.

Finally, the Advocate reduced the Company's forecast of the remaining items of A&G Expense from $1,279,552 to $1,122,722. However, the Directors found that the Advocate failed to document its reasoning for this reduction in its testimony or through cross-examination at the Hearing. Therefore, the Directors unanimously adopted $1,279,552 as the appropriate level of A&G Expense relating to "other items" of A&G Expense.

The total for all three components of A&G Expense equals $2,186,146. Therefore, the Directors unanimously approved this amount as the proper level of A&G Expense.

36 Gerald A. Hinesley Pre-Filed Direct Testimony, at page 4, and Company Workpaper O&M-1.
37 R. Terry Buckner Pre-Filed Direct Testimony, at page 14.

V(b)11. CORPORATE ALLOCATIONS

During the 1996 fiscal year, corporate shared services were allocated based on a percentage of approximately 3.8 percent[38] of AGL's customers in Tennessee and Georgia. Beginning in October 1996, the Company changed its allocation methodology. The new overhead allocation methodology uses numerous allocation percentages, depending on the type of service rendered. Allocations can be based on the number of full-time employees, number of users, hours used, number of customers or any combination of these drivers. The allocation percentages are updated monthly using a computer allocation model.

James Kissel, a Senior Manager with Deloitte & Touche Consulting Group testifying for Chattanooga Gas, stated that the purpose of his testimony was to "demonstrate that the methodology is rational, fair and equitable." [39] He also stated that his testimony "addresses only the approach to allocating costs and not the actual cost levels of the various business functions." [40] In his Pre-filed testimony, he goes into great detail describing the various services that are allocated and the rationale for selecting the appropriate drivers to allocate these services. Using a "typical year," he stated that Chattanooga Gas would receive a composite allocation of 3.7 percent. [41] This was reiterated where he stated that, ". . . the new methodology allocates 3.7 percent of the central service costs to Chattanooga Gas Company." [42] He detailed, as did Mr. Thompson, President of Chattanooga Gas Company, [43] that there was an increase in cost allocation to Chattanooga Gas due to the inclusion of costs not formerly allocated to Chattanooga Gas. [44] Mr. Kissell's estimate of the

---

38 James E. Kissel, Pre-Filed Direct Testimony, at page 15.
39 Id., at page 2.
40 James E. Kissell Pre-Filed Direct Testimony, at page 2.
41 Id, at page 11.
42 Id, at page 13.
43 Harrison F. Thompson Pre-Filed Direct Testimony,at page 5
44 James E. Kissell Pre-Filed Direct Testimony, at pages 11-13.

increase to Chattanooga Gas, when costs were fully allocated, was approximately $2.3 million. [45] Mr. Kissell also responded that allocating costs on a single driver, such as customers, does not accurately reflect the amount of resources consumed by the individual business organization. [46]

The Advocate argued that there were several problems with accepting the Company's new methodology for allocating common costs. First, because the methodology is excessively complex, it would be extremely difficult for a regulator to verify that costs are being accurately allocated to Tennessee. Secondly, because there are multifactors involved, the potential exists for AGL to manipulate costs between jurisdictions, thereby recovering over or under 100 percent of its common costs. A company's "external auditors rarely, if ever, certify the accuracy of charges between jurisdictions, but usually examine only the Company's operations in total." [47] Instead, the Advocate recommends that AGL allocate its common costs using a single allocation component based upon the number of customers in Georgia and Tennessee. [48] The Advocate also argued that this methodology would not only leave a cleaner audit trail, but also allow regulators to verify the accuracy of the charges allocated to Tennessee and Georgia customers.

In addition to disagreeing with the Company's allocation methodology, the Advocate also disagreed with the Company's allocated expenses of $5.227 million. The Company annualized their fiscal year-to-date base costs. These annualized costs were then allocated to Chattanooga Gas using the new allocation model.

The Advocate also annualized the base costs to be allocated, and then used a single allocation percentage of 3.73 percent based on the number of Tennessee customers. The Advocate argued that the Company claimed that the new methodology allocates 3.7 percent of the central

45 James E. Kissell Pre-Filed Direct Testimony , at page 11.
46 Id., at page 15.
47 R. Terry Buckner Pre-Filed Direct Testimony, at page 8.
48 Id., at page 5.

service costs, while the actual composite percentage allocated to Chattanooga Gas in the Company's case is 5.13 percent. These different approaches account for $1.249 million of the difference between the Advocate and the Company's case for this item. The Advocate next indicated that the difference in the rate of return on allocated net assets accounts for an additional $0.155 million. Finally, the Advocate argued an additional difference of $0.093 million occurred because the Company did not allocate any of its corporate office costs to non-utility operations. As a result of its analysis, the Advocate recommended an inclusion of $3.730 million in Corporate Allocated Expenses.

AVI stated that the Company did not provide support for the allocation factors used to forecast its estimated shared service allocation to Chattanooga Gas.[49] AVI also argued that this item represents the largest single adjustment to the test year cost of service, and that the Company should be compelled to provide support to show the complete derivation of all elements used to establish this reallocation. Absent a clear demonstration of support for the Company's calculations, AVI asked that the reallocation be rejected.[50]

While Company witness James Kissel testified that the new methodology is the "most fair, equitable and rational approach,"[51] his colleague at Deloitte & Touche, Gregory E. Aliff, co-author of ACCOUNTING FOR PUBLIC UTILITIES, stated that:

> For a utility, the basic goals of intercompany cost allocation methodologies are to:
> (1) prevent or limit, to the extent possible, any cross-subsidization of one activity or entity by another; and
> (2) minimize the time and expense necessary to reflect and audit the transactions.
>
> The second goal of a cost allocation system is to minimize the time and expense necessary to record and audit transactions. This goal is important because the system for

49 Michael Gorman Pre-Filed Direct Testimony, at page 22.
50 Id., at page 22.
51 James E. Kissell Pre-Filed Direct Testimony, at page 15.

allocating shared costs must be understandable and workable. The personnel responsible for the accounting and reporting of the costs must be able to apply the system properly if it is to produce the desired results. In addition, an overly detailed or complex system could increase business costs and diminish any cost benefits of the shared activities. Thus, it is possible for the system to impact the economics of the business transaction.

The time and expense necessary to audit the transactions is also an important consideration. Similar to accounting and reporting for these transactions, auditing intercompany transactions should not impose an extreme cost burden or be so time consuming as to prevent effective system testing. These requirements would most likely result in resistance to or nonacceptance of the system by regulators and others." [52]

The Directors' review of the record in this matter compelled them to concur with the Advocate in concluding that the complexity of the allocation methodology implemented by Chattanooga Gas makes it difficult to accept. The Directors made no judgments regarding the accuracy of AGL's allocation methodology, but did conclude that regulation requires a more audit-friendly environment. The Directors found further that the burden for determining fairness, equity, and accuracy of costs imposed on Tennessee ratepayers should not shift to the Authority either by design or by chance. While the Directors stated that they fully endorse systems that more accurately ascribe costs to cost causes, they determined that an allocation system must minimize the time and expense necessary to reflect and audit transactions. Therefore, the Directors unanimously concluded that the use of a single allocation formula based on customers in Tennessee and Georgia is the most appropriate method of allocation of common cost at the present time. Additionally, the Directors found that the Advocate correctly asserted that the Company did not allocate any of its corporate office costs to nonutility operations. Therefore, the Directors unanimously adopted the Advocate's forecast of $3.730 million in Corporate Allocated Expenses. Additionally, the Directors unanimously adopted the Advocate's recommendation for a single allocation factor, based on

---

52 R.L. HAHNE AND G.E. ALIFF, ACCOUNTING FOR PUBLIC UTILITIES, Matthew Bender, Accounting Series, §19.02, page 19-4, 19-5.

customers for financial reporting purposes, and that this factor shall only be updated within a rate case.

V(b)12. INTEREST ON CUSTOMER DEPOSITS

Authority rules require gas utilities to accrue interest on Customer Deposits. This interest is then refunded to the customer along with the security deposit after a specified period when credit worthiness has been demonstrated.

The Company and AVI forecasted incorrect amounts for this issue. The Advocate had attempted to correct the error but ignored its effect on accrued interest in customer deposits. Therefore, the Directors found that the Advocates' forecast should be discarded. The Directors concluded that the test period balance for this account was representative of the attrition year. The Directors, therefore, unanimously adopted the test period balance of $126,744 for Interest on Customer Deposits.

V(b)13. MISCELLANEOUS EXPENSE RELATING TO CHARITABLE DONATIONS

The Company included $37,540, in their case as Miscellaneous Expense. This item represents donations to the civic, community and charitable organizations of Chattanooga and Cleveland, Tennessee. According to testimony from the Company's witness, Chattanooga Gas feels a responsibility to be a good corporate citizen and therefore makes these donations to various organizations. [53]

The Advocate objects to these types of expenses and has excluded them from their case. According to the Advocate, charitable donations should not be allowed in setting rates. [54] AVI accepted the Company's calculation for charitable donations in their case.

---

53 Gerald A. Hinesley Pre-Filed Rebuttal Testimony, at page 4.
54 R. Terry Buckner Pre-Filed Direct Testimony, at page 14.

A majority of the Directors found that accounting principles and standards under which regulated companies operate generally will not support charitable contributions in a rate case. The majority concluded that such a finding is consistent with the Authority's position in the Nashville Gas[55] case although charitable contributions were voluntarily withdrawn. A majority of the Directors concluded that this was an inappropriate recovery, and adopted the Advocate's position in which Miscellaneous Expenses in the determination of Net Operating Income were excluded.[56]

V(b)14. DEPRECIATION AND AMORTIZATION EXPENSE

Depreciation and Amortization Expense represent the systematic recovery of capital invested in assets placed in service by the Company. As Depreciation and Amortization Expenses are recognized, the balance of Accumulated Depreciation is increased in determining the proper level of Rate Base.

In this case, the Company submitted a new depreciation study, which changes their depreciation rates. The greatest reason for the change in depreciation rates is the Company's projected "net salvage value" percentage.

The Company testified that, historically, Account #376 (Mains) has experienced a negative salvage rate of 20 percent, but due to increases in the cost of removal related to cast iron main replacement, a negative 40 percent salvage value has been used in the proposed depreciation rates. For Account #380 (Services) the Company testified that the current rates include a 60 percent negative salvage rate and that they anticipate a "modest adjustment" in the salvage rate of this asset; therefore, the Company used a 55 percent negative salvage rate.[57]

---

[55] In Re: Application of Nashville Gas Company, a Division of Piedmont Natural Gas Company, Inc. for an Adjustment of its Rates and Charges, Docket No. 96-00977 (Tenn. Reg. Authority, February 19, 1997).

[56] Director Greer voted no on this Issue, having previously moved to allow this expense to be included on the basis of public expectations that utilities would participate in the community.

[57] Donald Roff Pre-Filed Direct Testimony, at page 11.

Based on a historical analysis of the past fifteen years, AVI contended that a negative 15 percent salvage value more accurately reflects what will occur in the future for Account #376 (Mains). Reducing the net salvage value from 40 percent to 15 percent effectively reduces the annual depreciation percentage for this account from 2.81 percent to 2.31 percent. AVI testified that the net salvage value for Account #380 (Services) has averaged 42 percent over the last five years. Reducing the net salvage value from 55 percent to 40 percent effectively reduces the annual depreciation percentage for this account from 4.43 percent to 4.00 percent.[58] If AVI's salvage rates are used for these two categories, the result is an annual decrease in Depreciation and Amortization Expense of $476,157. The Advocate proposed eliminating depreciation on land rights that would reduce the Company's Depreciation Expense by approximately $10,000.[59]

The Directors concluded that both AVI and the Advocate made solid arguments for the proper calculation of depreciation expense. However, the Directors were hesitant to accept AVI's or the Advocate's proposal without an accumulated depreciation quantification in the record. The Directors determined that absent such quantification in the record, the Company's proposal for purposes of this case must be given greater weight. Accordingly, the Directors approved the Company's forecast of $4,820,597 for Depreciation and Amortization Expense.

V(b)15. TAXES OTHER THAN INCOME

Taxes Other Than Income includes Property Taxes, Franchise Taxes, Gross Receipts Taxes, Authority Fees, Payroll Taxes, and Other General Taxes. The Company included $3,952,807 in their case for Taxes Other Than Income, while the Advocate only forecasted $3,552,189 for a difference between these Parties of $400,618. AVI accepted the Company's forecast of Taxes

---

58 James T. Selecky Pre-Filed Direct Testimony, at page 2.
59 R. Terry Buckner Pre-Filed Direct Testimony, at page 19.

Other Than Income in its forecast of NOI. The Directors determined that Taxes Other Than Income may be illustrated by each of the specific components shown in the following table.

TAXES OTHER THAN INCOME

	Company and AVI	Consumer Advocate	Authority
Property Taxes	$2,310,714	$2,094,035	$2,094,035
Gross Receipts Tax	692,453	541,741	541,741
Payroll Taxes	242,890	238,749	242,890
TRA Inspection Fee	168,804	166,058	166,058
Franchise Tax	267,321	240,981	240,981
Other General Taxes	270,625	270,625	270,625
Total Taxes Other Than Income	**$3,952,807**	**$3,552,189**	**$3,556,330**

The Advocate stated that the Company calculated their Property Taxes incorrectly by using the unequalized assessment value. In addition, the Advocate argued that the Company incorrectly calculated Gross Receipts Taxes by taking a five year average of the effective rate, which does not reflect the current effective tax rate. The Advocate then argued that the Company used its proposed Acquisition Adjustment in its calculation of the Franchise Tax. Since the Advocate recommended disallowance of the Acquisition Adjustment, they also recommended that it be removed from the Franchise Tax Calculation.[60]

Finally, the Advocate reduced the Company's payroll taxes based on its proposed reduction in Salary and Wage Expense. Parallel to the Advocate's recommended disallowance of a portion of the Salary and Wage Expense, was the Advocate's recommendation that the associated payroll taxes be removed.[61]

60 R. Terry Buckner Pre-Filed Direct Testimony, at page 16.
61 Id., at page 17.

The Directors determined from the record that of the various adjustments that the Advocate made to Taxes Other Than Income, the only issue to which the Company took exception was the Advocate's adjustment to payroll taxes. The record reflects that the Company's exception resulted from its belief that the Advocate's payroll adjustments were inappropriate.[62] Therefore, because the Directors adopted the Company's calculation of Salary and Wage Expense, they also adopted the Company's calculation of payroll taxes. Further, the Directors found that there was a lack of discussion on the record contrary to the position of the Advocate on the remaining components of Taxes Other Than Income. Therefore, the Directors unanimously adopted the Advocate's forecast of Taxes other than Income. In addition, the Directors concluded that adoption of these adjustments results in a total forecast of $3,556,330 for Taxes Other Than Income. Therefore, the Directors unanimously approved $3,556,330, as the appropriate amount of Taxes Other Than Income.

V(b)16. TENNESSEE EXCISE TAX EXPENSE

Tennessee Excise Tax Expense represents the Company's income tax due to the state based on the tariffs currently in place. The Tennessee Excise Tax is a 6 percent income tax on the earnings of the Company. After considering all of the previous adjustments, a forecast of $545,670 for Tennessee Excise Tax Expense was calculated. The Directors, therefore, unanimously approved $545,670 as the appropriate forecast amount for Tennessee Excise Tax based upon the decisions adopted within this Order. See the chart following Section V(b)17 for calculations.

---

62 Gerald A. Hinesley Pre-Filed Rebuttal Testimony, at page 4.

V(b)17. FEDERAL INCOME TAX EXPENSE

Federal Income Tax Expense represents the Company's current income tax due to the federal government based on the tariffs currently in place. The federal income tax is a 35 percent income tax on the earnings of the Company.

Taking all previous adjustments into account, a forecast of $2,992,092 for Federal Income Tax Expense is calculated. The Directors unanimously determined that the Federal Income Tax Expense must be calculated based upon the results of the decisions adopted within this Order. See the following chart.

CHATTANOOGA GAS COMPANY
Excise and Income Taxes
For the 12 Months ending September 30, 1998

Line No.		Authority	Company	Consumer Advocate	AVI
1	Operating Revenues	$ 32,711,499	$ 32,136,117	$ 32,697,029	$ 32,771,581
2	Salaries and Wages	3,136,136	3,136,136	3,084,307	3,136,136
3	Distribution Expense	927,379	980,895	1,368,826	980,895
4	Storage Expense	896,551	987,610	794,418	987,610
5	Customer Relations Expense	97,232	487,858	206,015	487,858
6	Sales Promotion Expense	430,670	455,531	455,531	455,531
7	Administrative and General Expense	6,054,152	7,675,537	5,575,270	7,489,537
8	Interest on Customer Deposits	126,744	225,965	115,034	225,965
9	Miscellaneous Expense	0	37,540	0	37,540
10	Depreciation & Amortization Expense	4,820,597	5,231,621	4,810,722	4,344,440
11	Taxes Other Than Income	3,556,330	3,952,808	3,552,189	3,952,807
12	NOI Before Excise and Income Taxes	$ 12,665,708	$ 8,964,616	$ 12,734,717	$ 10,673,262
13	AFUDC	32,373	32,373	32,373	32,373
14	Interest Expense	3,603,577	3,933,485	3,667,147	3,400,312
15	Pre-tax Book Income	$ 9,094,504	$ 5,063,504	$ 9,099,943	$ 7,305,323
16	Schedule M Adjustments	0	0	0	0
17	Excise Taxable Income	$ 9,094,504	$ 5,063,504	$ 9,099,943	$ 7,305,323
18	Excise Tax Rate	6.00%	6.00%	6.00%	6.00%
19	Excise Tax Payable	$ 545,670	$ 303,810	$ 545,997	$ 438,319
20	Excise Tax - Deferred	0	0	0	0
21	State Income Tax Expense	$ 545,670	$ 303,810	$ 545,997	$ 438,319
22	Pre-tax Book Income	$ 9,094,504	$ 5,063,504	$ 9,099,943	$ 7,305,323
23	Excise Tax	545,670	303,810	545,997	438,319
24	Schedule M Adjustments	0	0	0	0
25	FIT Taxable Income	$ 8,548,834	$ 4,759,694	$ 8,553,946	$ 6,867,004
26	FIT Rate	35.00%	35.00%	35.00%	35.00%
27	Federal Income Tax Payable	$ 2,992,092	$ 1,665,893	$ 2,993,881	$ 2,403,451
28	ITC Amortization	0	0	0	0
29	Amortization of Excess Deferred FIT	0	0	0	0
30	FIT - Deferred	0	0	0	0
31	Federal Income Tax Expense	$ 2,992,092	$ 1,665,893	$ 2,993,881	$ 2,403,451
32	Total Federal and State Income Taxes	$ 3,537,762	$ 1,969,703	$ 3,539,878	$ 2,841,771

V(b)18. CALCULATION OF NET OPERATING INCOME

After each of the previous adjustments is taken into account, a Net Operating Income of $9,160,319 is calculated as follows.

COMPARATIVE NET OPERATING INCOME CALCULATIONS

	Company[63]	Consumer Advocate[64]	AVI[65]	Authority
Base Rate Revenues	$31,206,762	$31,813,280	$31,842,220	$31,827,750
Other Revenues	929,361	883,749	929,361	883,749
AFUDC	32,373	32,373	32,373	32,373
Net Revenues	**$32,168,496**	**$32,729,402**	**$32,803,954**	**$32,743,872**
Salaries & Wages	$3,136,136	$3,084,307	$3,136,136	$3,136,136
Distribution Expense	980,895	1,368,826	980,895	927,379
Storage Expense	987,610	813,689	987,610	896,551
Customer Accounts Expense	102,839	126,867	102,839	97,232
Uncollectible Expense	385,019	165,968	199,019	138,006
Sales Promotion Expense	455,531	79,148	455,531	430,670
Admn & General Expense	2,448,665	2,115,562	2,448,665	2,186,146
Corporate Allocations	5,226,872	3,730,000	5,226,872	3,730,000
Interest on Customer Deposits	225,965	115,034	225,965	126,744
Miscellaneous Expense	37,540	0	37,540	0
Depr & Amort Expense	5,231,621	4,810,722	4,344,440	4,820,597
Taxes Other Than Income	3,952,807	3,552,189	3,952,807	3,556,330
Tennessee Excise Tax Expense	303,810	545,997	438,319	545,670
Federal Income Tax Expense	1,665,893	2,993,881	2,403,451	2,992,092
Total Operating Expenses	**$25,141,203**	**$23,502,190**	**$24,940,089**	**$23,583,553**
Net Operating Income	**$7,027,293**	**$9,227,212**	**$7,863,865**	**$9,160,319**

V(c). CAPITAL STRUCTURE AND FAIR RATE OF RETURN

The Directors found that, although the Advocate and AVI did not endorse Chattanooga Gas' proposed capital structure and cost rates for short- and long-term debt and preferred stock, neither did they suggest any alternatives. Therefore, the Directors adopted the capital structure and cost rates on debt and preferred stock proposed by Chattanooga Gas.

63 Chattanooga Gas Exhibit 5, Schedule 4.
64 Advocate Pre-Filed Exhibit, Schedule 8.
65 AVI Schedule MPG-1.

On cost of equity, none of the witnesses' analyses went completely unrebutted. The Directors rejected the position of Dr. Andrews, the Chattanooga Gas witness, that Chattanooga Gas is an independent firm. The Directors adopted the testimony of Dr. Brown, for the Consumer Advocate, and Mr. Gorman, for AVI, that AGL is the appropriate company to reference for determining the cost of equity. This finding eliminated all of the cost of equity estimates underlying Dr. Andrews' recommended cost of equity of 12.25 percent, since he relied on data for firms "comparable" to Chattanooga Gas and not AGL. Moreover, the Directors concluded that Dr. Andrews' DCF estimate of 11.06 percent is biased and that his Capital Asset Pricing Model is flawed.

Dr. Brown's DCF estimate along with his capital asset pricing model and Mr. Gorman's DCF estimate and risk premium estimate of the cost of equity, taken as a group, provided enough useful information for deciding the cost of equity in this case. These estimates defined a range, from Dr. Brown's DCF estimate at 10.4 percent to his capital asset pricing model at 11.14 percent that includes Dr. Andrews' DCF calculation of 11.06 percent as well as Dr. Brown's recommended 10.55 percent and Mr. Gorman's recommended 10.80 percent.

The Directors rejected Dr. Brown's compounding theory that formed the basis of his recommended 10.55 percent cost of equity. This theory was rebutted by Dr. Andrews and not recommended by any other witnesses. This decision is consistent with the decision of the Authority in the most recent Nashville Gas Company rate case. Further, Dr. Brown testified at the Hearing that he did not know of any other jurisdiction where this approach had been adopted.

The Directors found that the range established between witness Dr. Brown's DCF estimate at 10.4 percent and his capital asset pricing model at 11.14 percent was sufficient to encompass returns on equity proffered by all Parties in this proceeding. Although Chattanooga Gas' witness

Andrews' DCF estimate was found to be biased, the upper range of his model at 11.06 percent is within the range identified by Dr. Brown between his DCF calculation on the low side at 10.4 percent and his capital asset pricing model estimate on the high side at 11.14 percent. Therefore, the Directors unanimously adopted 11.06 percent as the cost of equity in this proceeding. The Directors further noted for the record that this percentage falls within the range supported by all Parties.

The resulting overall cost of capital of 9.08 percent flows from the decisions on capital structure and cost rates as shown in the following table.

CAPITAL STRUCTURE AND COST OF CAPITAL

Component	Percent	Cost Rate	Weighted Cost
Short Term Debt	5.28	5.80 %	0.31 %
Long Term Debt	46.07	7.75 %	3.57 %
Preferred Stock	4.49	7.04 %	0.32 %
Common Equity	44.16	11.06 %	4.88 %
Total	100.00		9.08 %

V(d). REVENUE CONVERSION FACTOR

The Directors unanimously adopted a revenue conversion factor of 1.634321, illustrated below, to reflect the changes to the Company's rate case amounts for other revenues and uncollectible expenses.

REVENUE CONVERSION FACTOR

Line		Rate	Balance
1	Operating Revenues		1.000000
2	Add: Forfeited Discount Ratio	0.006837[66]	0.006837
3	Balance		1.006837
4	Deduct: Uncollectible Ratio	0.005368[67]	0.005405
5	Balance		1.001432
6	Deduct: State Excise Tax Rate	0.060000[68]	0.060086
7	Balance		0.941346
8	Deduct: Federal Income Tax Rate	0.350000[69]	0.329471
9	Balance		0.611875
10	Revenue Conversion Factor (Line 1/Line 9)		1.634321

V(e). REVENUE DEFICIENCY OR SURPLUS

The Directors found, that after placing into effect their decisions with respect to Docket No. 97-00982, Chattanooga Gas Company, Petition to Place Into Effect the Revised Natural Gas Tariff, the calculations from these decisions indicate that there is a revenue surplus in the amount of $1,166,213[70] as illustrated in the following chart.

66 See Section V(b)2.
67 See Section V(b)8.
68 Statutory Rate.
69 Statutory Rate.
70 The revenue design calculation deficiency was announced at the Authority Conference on July 21, 1998.

COMPARATIVE REVENUE DEFICIENCY (SURPLUS) CALCULATIONS

	Company	Consumer Advocate	AVI	Authority
Rate Base	$101,378,494	$94,595,399	$87,712,302	$92,955,599
Operating Income at Current Rates	$7,027,293	$9,227,212	$7,863,865	$9,160,319
Earned Rate of Return[71]	6.93%	9.75%	8.97%	9.35%
Fair Rate of Return	9.61%	8.85%	8.97%	9.09%
Required Operating Income[72]	$9,742,473	$8,371,693	$7,867,793	$8,446,742
Operating Income Deficiency (Surplus)[73]	$2,715,180	$(855,519)	$3,928	$(713,577)
Gross Revenue Conversion Factor	1.628843	1.628727	1.628843	1.634321
Revenue Deficiency (Surplus)[74]	**$4,422,602**	**$(1,393,407)**	**$6,399**	**$(1,166,213)**

V(f). RATE DESIGN

V(f)1. IGCA RIDER, LOST AND UNACCOUNTED FOR PROVISION AND DAILY BALANCING PROVISION

The Directors found that there was mirroring in the Company's proposal to change the industrial tariff by including an interruptible gas cost adjustment ("IGCA") rider, a lost and unaccounted for provision, and a daily balancing provision. The Directors concluded that these changes could better reflect the cost of providing service to the industrial class. However, the Directors unanimously found that these types of tariff changes can best be negotiated between the Parties outside the context of a rate case, and denied the Company's request.

71 Operating Income at Current Rates / Rate Base.
72 Rate Base multiplied by Fair Rate of Return.
73 Required Operating Income - Operating Income at Current Rates.
74 Operating Income Deficiency (Surplus) multiplied by Gross Revenue Conversion Factor.

V(f)2. MISCELLANEOUS CHARGES FOR RECONNECTION AND SERVICE ESTABLISHMENT

The Directors unanimously determined from the record that rates charged by Chattanooga Gas for Reconnection and Service Establishment are higher than those of Nashville Gas and United Cities Gas, and therefore, concluded that these rates shall not be increased at this time.

V(f)3. BILLING VOLUME FOR OUTDOOR LIGHTING

The Directors found that the Company's proposal to change the billing volume for outdoor lighting was appropriate. The Directors further found that the Company's proposal to reduce the minimum daily volumes to qualify for the firm transportation tariff was appropriate. There was no opposition to these issues by the Advocate, AVI or CMA, and therefore, the Directors unanimously approved these two changes.

V(f)4. DETARIFFING

Detariffing is a term used to indicate the Company's proposal to substitute price cap formula regulation for some or all of the industrial segment of the Chatanooga Gas tariff. The Directors found that a formula may satisfy the tariff rate requirements of Rule 1220-4-1-.03. The Directors further found that rates do not have to be the same for all classes of customers to be nondiscriminatory.[75] However, while concluding that creative rate designs under strict rate of return regulations should not be discouraged, the Directors emphasized that there is an effective experimental bypass rule in place which, when properly applied, would effectively assist in keeping industry in the Company's industrial base. Therefore, the Directors unanimously rejected the Company's proposal for industrial rate detariffing.[76]

---

75 CF Industries v. Tennessee Public Service Commission, 599 S.W.2d 536 (Tenn. 1980).

76 Chairman Malone did not agree with the rationale expressed by the majority, but joined in the result.

VI. SETTLEMENT OF RATE DESIGN ISSUES

On July 16, 1998, the Parties jointly submitted a Motion to Postpone a Decision on Rate Design to Allow the Parties to Propose a Settlement. This Motion was considered by the Directors at the Authority Conference on July 21, 1998. At that Conference the Directors unanimously approved the Motion to allow the Parties an opportunity to negotiate the Rate Design. The Parties were given until 12:00 Noon on Tuesday, July 28, 1998, to propose their Rate Design. On July 28, 1998, the Parties timely filed their proposed Rate Design. The proposed Rate Design is attached as Exhibit A. The proposed Rate Design settlement was considered by the Directors at the Authority Conference on August 4, 1998. At that Conference, the Directors unanimously approved the proposed Rate Design settlement and ordered that the tariffs, consistent with the provisions of the settlement, shall be filed not later than three (3) business days after the entry of a final Order in this case and shall be effective upon approval of the Authority.

VI(a). WEATHER NORMALIZATION

As a part of the Parties' proposed settlement of Rate Design, they agreed to permit the Company and the Authority Staff to determine the details of the Weather Normalization Adjustment ("WNA") factors. The WNA factors are used on a going forward basis to adjust the residential and commercial rates for weather that is either above or below the normal seasonal range. Accordingly, the Company and the Authority Staff agreed to jointly issue the use of the existing WNA factors from the Company's 1995 rate case, Docket No. 95-02116. The proposed Rate Design settlement, including adoption of the WNA factors, was considered by the Directors at the Authority Conference on August 4, 1998. At that Conference, the Directors unanimously approved the proposed Rate Design, including the provisions of the proposed settlement concerning the WNA factors.

VII. DISPOSITION OF THE MOTION TO STRIKE REQUEST OF FINDINGS FROM CHATTANOOGA GAS BY THE ADVOCATE

On September 29, 1997, the Consumer Advocate Division filed an Objection and Motion to Strike Request of Findings submitted by Chattanooga Gas. The Hearing Officer requested the Parties to submit proposed charges of law, but did not request the Parties to file any proposed findings of fact or the Request of Findings as submitted by Chattanooga Gas. Therefore, the Directors unanimously granted the Objection and Motion to Strike Request of Findings submitted by the Advocate.

IT IS THEREFORE ORDERED THAT:

1. The rates filed by Chattanooga Gas Company on May 1, 1997, are denied;

2. For purposes of the rates herein, the annual test period shall be the historical test period for the twelve (12) months that ended September 30, 1996, with adjustments for attrition through September 30, 1998;

3. For purposes of the rates herein, the cost of equity shall be 11.06 percent and the cost of capital shall be 9.08 percent;

4. The request of the Company for an Acquisition Adjustment to Rate Base is denied;

5. The allocation factor for the financial reporting of corporate expense shall be based on customers and be updated within a rate case;

6. The request of the Company for an industrial tariff interruptible gas cost adjustment rider, a lost and unaccounted for provision and a daily balancing provision is denied;

7. The request of the Company for an increase in Reconnection and Service Establishment is denied;

8. The request of the Company to change the billing volume for outdoor lighting is approved;

9. The request of the Company to reduce the minimum daily volume to qualify for the firm transportation tariff is approved;

10. The proposal of the Company for industrial rate detariffing is denied;

11. The Agreement on a Rate Design negotiated among the Parties and submitted in a filing to the Authority on July 28, 1998, is approved;

12. The Agreement among the Parties to permit the Authority Staff and the Company to determine the details of the Weather Normalization Adjustment factors is approved;

13. The Company is directed to file tariffs with the Authority that are designed to produce a reduction of $1,166,213 in revenue for service rendered;

14. The tariffs shall be filed not later than three (3) business days after the date of entry of this Order and shall be effective upon approval of the Authority;

15. Chattanooga Gas Company shall file any and other tariffs necessary to be consistent with this Order;

16. The Objection and Motion to Strike Request of Findings submitted by the Office of the Attorney General, Consumer Advocate Division is granted;

17. Any party aggrieved with the Authority's decision in this matter may file a Petition for Reconsideration with the Authority within ten (10) days from and after the date of this Order; and

18. Any party aggrieved with the Authority's decision in this matter has the right of judicial review by filing a Petition for Review in the Tennessee Court of Appeals, Middle Division, within sixty (60) days from and after the date of this Order.

CHAIRMAN

Sara Kyle

DIRECTOR

Lynn Greer

DIRECTOR

ATTEST:

K. David Waddell

EXECUTIVE SECRETARY

RECEIVED
JUL 28 1998
TN REGULATORY AUTHORITY
GENERAL COUNSEL'S OFFICE

BOULT
CUMMINGS
CONNERS
& BERRY PLC

REC'D TN
REGULATORY AUTH.
'98 JUL 28 PM 12 46
OFFICE OF THE
EXECUTIVE SECRETARY

Henry Walker
(615) 252-2363
Fax: (615) 252-6363
Email: hwalker@bccb.com

LAW OFFICES
414 UNION STREET, SUITE 1600
POST OFFICE BOX 198062
NASHVILLE, TENNESSEE 37219

TELEPHONE (615) 244-2582
FACSIMILE (615) 252-2380
INTERNET WEB http://www.bccb.com/

July 28, 1998

Mr. David Waddell, Executive Secretary
Tennessee Regulatory Authority
460 James Robertson Parkway
Nashville, Tennessee 37243

Re: *Petition of Chattanooga Gas Company*
Docket No. 97-00982

Dear David:

Attached is a rate design proposal submitted on behalf of all the parties to this case. The proposal is complete except for calculations relating to weather normalization which, the parties agree, should be worked out between Chattanooga and the TRA's technical staff. The proposed tariff provides rate reductions for all customer classes and addresses the problem of bypass by large industrial users.

The proposed tariff has been reviewed by rate design experts from Chattanooga and AVI/CMA. Chattanooga does not oppose the proposed tariff. AVI/CMA agrees to the proposal. The Consumer Advocate's Office has also reviewed and agreed to the proposal. In order to meet the TRA's noon deadline for filing this proposal, counsel for Chattanooga and the Consumer Advocate, both of whom are out of town, have authorized counsel for AVI/CMA to file this agreement on behalf of all parties. The parties' rate design experts (Dan McCormac, Don Johnstone, and Lisa Howard Wooten) are available to answer any questions the TRA or its staff may have about this proposed rate design.

Respectfully submitted,

BOULT, CUMMINGS, CONNERS & BERRY, PLC

By: Henry

Henry Walker

HW/dc
Enclosure
cc: Parties of Record

0502162.01
003320-012 07/28/98

Exhibit A

Chattanooga Gas Company
Gross Profit From Sales and Transportation of Gas
For the 12 Months Ending September 30, 1998

TRA #97-00982
CMA/AVI/CGC Settlement
7/28/98 11:00 am

	Proforma Dekatherms 1	Proforma Bills 2	Current Gross Profit Margin 3	Current Gross Profit 4	Proposed Increase in Gross Profit Margin 5	Proposed Gross Profit Margin 6	Proposed Gross Profit 7	Percent Increase in Gross Profit 8	Proposed Increase in Gross Profit 9
Residential - Winter		288,478	$ 7.50	$ 2,163,585	$ 0	$ 7.50	$ 2,163,585	0%	
First 2.5 Mcf	705,140		3.0050	2,118,946	(0.1050)	2.9000	2,044,906	-3%	
Next 2.5 Mcf	647,693		2.0050	1,298,624	(0.0050)	2.0000	1,295,386	0%	
Over 5 Mcf	2,303,847		1.8050	4,158,624	(0.0550)	1.7500	4,031,907	-3%	
Res. - Summer		281,512	$ 7.50	$ 2,111,340	$ 0	$ 7.50	$ 2,111,340	0%	
First 2.5 Mcf	440,446		2.7190	1,197,573	(0.6190)	2.1000	924,937	-23%	
Next 2.5 Mcf	126,646		1.5210	192,629	(0.0210)	1.5000	189,959	-1%	
Over 5 Mcf	76,227		0.4710	35,903	(0.0210)	0.4500	34,302	-4%	
R-4 Multi-fam-Winter		2,604	$ 6.00	$ 15,624	$ 0	$ 6.00	$ 15,624	0%	
Flat rate /Mcf	20,193		2.0860	42,123	(0.2860)	1.8000	36,347	-14%	
R-4 Multi-fam-Summer		2,604	$ 6.00	$ 15,624	$ 0	$ 6.00	$ 15,624	0%	
Flat rate /Mcf	6,779		1.7110	11,599	(0.1110)	1.6000	10,846	-6%	
Residential (R-1 & R-4)	4,327,071	286,720		$ 13,362,193			$ 12,874,774	-3.6%	$ (487,419)
C-1 Winter		48,417	$ 20.00	$ 968,340	$ 0	$ 20.00	$ 968,340	0%	
First 300 Mcf	2,219,623		2.8000	6,188,144	(0.0500)	2.7500	6,087,463	-2%	
Next 200 Mcf	295,764		2.5240	746,508	(0.0140)	2.5100	742,368	-1%	
Next 1000 Mcf	513,718		2.4610	1,264,260	(0.0160)	2.4450	1,256,041	-1%	
Over 1,500 Mcf	296,152		1.2820	379,667	(0.0170)	1.2650	374,632.28	-1%	
C-1 Summer		46,253	$ 15.00	$ 693,795	$ 0	$ 15.00	$ 693,795	0%	
First 300 Mcf	703,262		2.2990	1,616,799	(0.1400)	2.1590	1,518,343	-6%	
Next 200 Mcf	92,196		1.9140	176,463	(0.2000)	1.7140	158,024	-10%	
Next 1000 Mcf	196,265		1.7080	335,221	(0.1100)	1.5980	313,631	-6%	
Over 1,500 Mcf	88,554		1.2820	113,528	(0.0170)	1.2650	112,021	-1%	
Commercial (C-1)	4,399,534	94,670		12,492,724			12,224,658	-2.1%	(268,066)
Industrial - Other		863	$ 300.00	$ 264,900	$ 0	$ 300.00	$ 264,900	0%	
Demand Units	130,759		$ 3.06	$ 400,123	$ (0.06)	3.0000	$ 392,277	-2%	
0-1,500 Mcf	1,401,374		0.9088	1,273,589	(0.0200)	0.8888	1,245,541	-2%	
1,501-4,000 Mcf	1,731,019		0.7798	1,349,849	(0.0200)	0.7598	1,315,228	-3%	
4,001-15,000 Mcf	2,804,499		0.4712	1,321,480	(0.0400)	0.4312	1,209,300	-8%	
Over 15,000 Mcf	4,136,077		0.3200	1,323,545	(0.0550)	0.2650	1,096,060	-17%	
Industrial	10,072,969		0.5230	$ 5,933,464		0.4831	$ 5,523,307	-6.9%	$ (410,158)
Miscellaneous Items:									
Connections		1,297	30.00	38,910	0	$ 30.00	38,910	0%	
Seasonal Reconnects R-1		475	30.00	14,250	0	30.00	14,250	0%	
Seasonal Reconnects C-1		56	45.00	2,520	0	45.00	2,520	0%	
Service Establishment - Turn ons		7,336	15.00	110,040	0	15.00	110,040	0%	
Service Establishment - Meter Sets		3,070	25.00	76,750	0	25.00	76,750	0%	
Bad check & other fees				13,862			13,862		
Miscellaneous				256,332			256,332	0.0%	0
Gross Profit (before forfeited discounts)				$ 32,044,713			$ 30,879,070	-3.6%	$ (1,165,643)
Forfeited Discounts				627,247			619,277		(7,970)
Total	18,799,574	671,195		$ 32,671,960			$ 31,498,347		$ (1,173,613)

Source: CGC Exh. 11, Sch. 4 & TRA data request Item 76, sheet 28

djcgreva.xls

7/28/98

28-Jul-98 12:11P

The Directors, therefore, unanimously approved $686,049 which represents the thirteen (13) month test period average for this account, as the proper forecast for Accrued Interest on Customer Deposits. Therefore, the Directors found after considering the adjustments described previously, that a Rate Base of $92,955,599 is calculated as illustrated in the following table.

COMPARATIVE RATE BASE CALCULATIONS

	Company[17]	Advocate[18]	AVI[19]	Authority
Additions:				
Plant in Service and CWIP	$140,014,935	$140,614,494	$140,014,935	$140,014,935
Acquisition Adjustment	13,355,565	0	0	0
Cash	2,373,422	2,373,422	0	2,373422
Materials and Supplies	453,221	346,273	453,221	453,221
Gas Inventories	5,419,144	6,659,404	5,419,144	5,419,144
Deferred Rate Case Expense	200,668	47,309	200,668	178,834
Prepayments	1,189,348	769,193	1,189,348	1,189,348
Other Accounts Receivable	92,028	138,738	92,028	92,028
Lead/Lag Study	1,736,716	756,038	-396,530	660,923
Total Additions	**$164,835,047**	**151,704,871**	**$146,972,814**	**$150,381,855**
Deductions:				
Accumulated Depreciation	$46,569,377	$46,478,394	$46,569,377	$46,569,377
Accu Amort of Acq Adj.	4,196,041	0	0	0
Accumulated Deferred FIT	5,131,816	5,131,815	5,131,816	5,131,816
Customer Advances	384,855	384,974	384,855	384,855
Contributions in Aid of Const.	1,908,645	1,858,651	1,908,645	1,908,645
Reserve for Uncollectibles	278,723	257,864	278,723	278,723
Other Reserves	549,562	409,201	549,562	549,562
Customer Deposits	3,766,190	1,917,229	3,766,190	1,917,229
Accrued Int on Cust Deposits	671,344	671,344	671,344	686,049
Total Deductions	**$63,456,553**	**$57,109,472**	**$59,260,512**	**$57,426,256**
Rate Base	**$101,378,494**	**$94,595,399**	**$87,712,302**	**$92,955,599**

Source: TRA Order 10/7/1998 Docket 97-00982

17 Company Exhibit 5, Schedule 8, Page 1 of 4.
18 Consumer Advocate Pre-Filed Exhibit, Schedule 3.
19 AVI Exhibit MPG-1.

CHATTANOOGA GAS COMPANY

12 MONTHS ENDED 12/31/96

REF.		1996 AMOUNT		AVERAGE DAILY AMOUNT	LEAD LAG DAYS		DOLLAR DAYS
4-2	GAS USED IN UTILITY OPERATIONS	15,895		43	39.27		1,689
4-3	PAYROLL	3,456,302		9,443	12.00		113,316
4-4	UNCOLLECTIBLE ACCOUNTS	417,700		1,141	0	(1)	0
4-5	EQUIPMENT LEASES	127,507		348	24.71		8,599
4-6	PROPERTY LIABILITY INSURANCE	497,382		1,359	0	(1)	0
4-8	M & S ISSUES	104,914		287	22.94		6,584
4-9	TRANSPORTATION CLEARING	287,312		785	12.14		9,530
4-10	CASH VOUCHERS	5,355,911		14,634	25.62		374,923
4-12	AGA DUES	20,521		56	-56.13		-3,142
	SERVICE COMPANY CHARGES (2)						
4-11	EMPLOYEE BENEFITS OTHER THAN PENSIONS AND OPEB	1,281,853		3,502	40.20	(2)	140,780
4-11	PENSIONS	1,038,547		2,838	183.0		519,354
4-11	OTHER POST-RETIREMENT BENEFITS	1,663,357		4,545	0		0
	POSTAGE	126,354		345	40.20	(2)	13,869
	LEASE PAYMENTS	18,859		52	40.20	(2)	2,090
	TOTAL	14,412,415		39,377	30.16		1,187,592
		14,412,415					

Reconciliation:

12 mos 9/30/96	12,816,533.70
+ 3 mos 12/31/96	3,668,576.79
- 3 mos 12/31/95	2,072,695.00
12 mos 12/31/96	14,412,415.49

Source: Tennessee Regulatory Authority Staff Request May 6, 1997 Item 42

TRA Docket 97-00982

Notes:

(1) Associated average balance (prepaid/accrual) considered at working capital component of rate base. Therefore, zero lag days are appropriate.

(2) Such expenses will be included in Service Company charges in the future. Service Company charges are due for payment by the 25th of the following month. Lag days equal 15.2 + 25 = 40.2.

The Directors, therefore, unanimously approved $686,049 which represents the thirteen (13) month test period average for this account, as the proper forecast for Accrued Interest on Customer Deposits. Therefore, the Directors found after considering the adjustments described previously, that a Rate Base of $92,955,599 is calculated as illustrated in the following table.

COMPARATIVE RATE BASE CALCULATIONS

	Company[17]	Advocate[18]	AVI[19]	Authority
Additions:				
Plant in Service and CWIP	$140,014,935	$140,614,494	$140,014,935	$140,014,935
Acquisition Adjustment	13,355,565	0	0	0
Cash	2,373,422	2,373,422	0	2,373422
Materials and Supplies	453,221	346,273	453,221	453,221
Gas Inventories	5,419,144	6,659,404	5,419,144	5,419,144
Deferred Rate Case Expense	200,668	47,309	200,668	178,834
Prepayments	1,189,348	769,193	1,189,348	1,189,348
Other Accounts Receivable	92,028	138,738	92,028	92,028
Lead/Lag Study	1,736,716	756,038	-396,530	660,923
Total Additions	**$164,835,047**	**151,704,871**	**$146,972,814**	**$150,381,855**
Deductions:				
Accumulated Depreciation	$46,569,377	$46,478,394	$46,569,377	$46,569,377
Accu Amort of Acq Adj.	4,196,041	0	0	0
Accumulated Deferred FIT	5,131,816	5,131,815	5,131,816	5,131,816
Customer Advances	384,855	384,974	384,855	384,855
Contributions in Aid of Const.	1,908,645	1,858,651	1,908,645	1,908,645
Reserve for Uncollectibles	278,723	257,864	278,723	278,723
Other Reserves	549,562	409,201	549,562	549,562
Customer Deposits	3,766,190	1,917,229	3,766,190	1,917,229
Accrued Int on Cust Deposits	671,344	671,344	671,344	686,049
Total Deductions	**$63,456,553**	**$57,109,472**	**$59,260,512**	**$57,426,256**
Rate Base	**$101,378,494**	**$94,595,399**	**$87,712,302**	**$92,955,599**

Source: TRA Order 10/7/1998 Docket 97-00982

17 Company Exhibit 5, Schedule 8, Page 1 of 4.
18 Consumer Advocate Pre-Filed Exhibit, Schedule 3.
19 AVI Exhibit MPG-1.

CHATTANOOGA GAS COMPANY

12 MONTHS ENDED 12/31/96

REF.		1996 AMOUNT		AVERAGE DAILY AMOUNT	LEAD LAG DAYS		DOLLAR DAYS
4-2	GAS USED IN UTILITY OPERATIONS	15,895		43	39.27		1,689
4-3	PAYROLL	3,456,302		9,443	12.00		113,316
4-4	UNCOLLECTIBLE ACCOUNTS	417,700		1,141	0	(1)	0
4-5	EQUIPMENT LEASES	127,507		348	24.71		8,599
4-6	PROPERTY LIABILITY INSURANCE	497,382		1,359	0	(1)	0
4-8	M & S ISSUES	104,914		287	22.94		6,584
4-9	TRANSPORTATION CLEARING	287,312		785	12.14		9,530
4-10	CASH VOUCHERS	5,355,911		14,634	25.62		374,923
4-12	AGA DUES	20,521		56	-56.13		-3,142
	SERVICE COMPANY CHARGES (2)						
4-11	EMPLOYEE BENEFITS OTHER THAN PENSIONS AND OPEB	1,281,853		3,502	40.20	(2)	140,780
4-11	PENSIONS	1,038,547		2,838	183.0		519,354
4-11	OTHER POST-RETIREMENT BENEFITS	1,663,357		4,545	0		0
	POSTAGE	126,354		345	40.20	(2)	13,869
	LEASE PAYMENTS	18,859		52	40.20	(2)	2,090
	TOTAL	14,412,415		39,377	30.16		1,187,592
		14,412,415					

Source: Tennessee Regulatory Authority Staff Request May 6, 1997 Item 42

TRA Docket 97-00982

Reconciliation:

12 mos 9/30/96	12,816,533.70
+ 3 mos 12/31/96	3,668,576.79
- 3 mos 12/31/95	2,072,695.00
12 mos 12/31/96	14,412,415.49

Notes:

(1) Associated average balance (prepaid/accrual) considered at working capital component of rate base. Therefore, zero lag days are appropriate.

(2) Such expenses will be included in Service Company charges in the future. Service Company charges are due for payment by the 25th of the following month. Lag days equal 15.2 + 25 = 40.2.

Docket No.______
Exhibit 5
Schedule 8
Page 4 of 4

CHATTANOOGA GAS COMPANY
Working Capital Expense Lag
For the 12 Months Ending September 30, 1998

Line No.		Amount	Lag	Dollar Days
1	Salaries and Wages	$ 3,136,136	12.0	$ 37,633,632
2	Purchased Gas Expense	59,698,231	38.4	2,292,412,070
3	Pension Expense	137,000	183.0	25,071,000
4	Insurance Expense	266,736	0.0	0
5	Postage Expense	168,471	40.2	6,772,534
6	Other Operating Expenses	10,307,087	23.8	245,308,672
7	Depreciation Expense	4,820,597	0.0	0
8	Taxes Other Than Income Taxes	3,952,807	149.2	589,758,867
9	State Excise Tax	570,440	80.2	45,749,288
10	Federal Income Taxes - Current	3,127,915	31.3	97,903,740
11	Federal Income Taxes - Deferred	0	0.0	0 0
12	Interest Expense	3,933,485	0.0	0
13	Net Earnings	5,776,614	0.0	0
14	Total Cost of Service	$ 95,895,520	34.8	$ 3,340,609,803
15	Daily Cost of Service	$ 262,727		

Source: Ratebase Workpapers.

Docket No.__ __
Exhibit 5
Schedule 8
Page 3 of 4

CHATTANOOGA GAS COMPANY
Lead Lag Results
For the 12 Months Ending September 30, 1998

Line No.		Amount
1	Revenue Lag	41.6 A/
2	Expense Lag	34.8 B/
3	Net Lag	6.8
4	Daily Cost of Service	262,727 B/
5	Lead Lag Results	1,786,544
6	Taxes Collected (Withheld) Prepaid	(49,828)
7	Total	1,736,716

A/ Ratebase Workpapers.
B/ Exhibit 5, Schedule 8 Page 4 of 4, Lines 14 & 15.

RULES
OF
TENNESSEE REGULATORY AUTHORITY
DIVISION OF PUBLIC UTILITIES

CHAPTER 1220-4-7
PURCHASED GAS ADJUSTMENT RULES

TABLE OF CONTENTS

1220-4-7-.01 DEFINITIONS.

(1) "Gas Costs" shall mean the total delivered cost of gas paid or to be paid to Suppliers, including, but not limited to, all commodity/gas charges, demand charges, peaking charges, surcharges, emergency gas purchases, over-run charges, capacity charges, standby charges, gas inventory charges, minimum bill charges, minimum take charges, take-or-pay charges and take-and-pay charges, storage charges, service fees and transportation charges and any other similar charges which are paid by the Company to its gas suppliers in connection with the purchase, storage or transportation of gas for the Company's system supply.

(2) "Company" or "LDC" shall mean local gas distribution company regulated by the Tennessee Regulatory Authority.

(3) "Fixed Gas Costs" shall mean all Gas Costs based on the Company's right to demand gas or transportation on a daily or seasonal peak; but unless otherwise ordered by the Authority, shall not include other charges paid for gas reserve dedication (*e.g.*, reservation fees and gas inventory charges), minimum bill charges, minimum take charges, overrun charges. Emergency gas charges, take-or-pay and take-and-pay charges (all of which shall be considered commodity costs).

(4) "Gas Charge Adjustment' shall mean the per unit amount billed by the Company to its customers solely for Gas Costs. The Gas Charge Adjustment shall be separately stated for firm customers and for non-firm customers.

(5) "Suppliers" shall mean any person or entity, including affiliates of the Company, who locates, purchases, sells, stores and/or transports natural gas or its equivalent for or on behalf of the Company. Suppliers may include, but not be limited to interstate pipeline transmission companies, producers, brokers, marketers, associations, intrastate pipeline transmission companies, joint ventures, providers of liquefied natural gas (LNG), liquefied petroleum gas (LPG), substitute, supplemental or synthetic natural gas (SNG), and other hydrocarbons used as feed-stock, other distribution companies and end-users.

(6) "Computation Period" shall mean the twelve (12) month period utilized to compute Gas Costs. Such period shall be the twelve (12) month period ending on the last day of a month which is no more than 62 days prior to the filing date of a Purchased Gas Adjustment (PGA).

(7) "Demand Billing Determinants" shall mean the annualized volumes for which the Company has contracted with Suppliers as of the first day of the Filing Month.

(8) "Commodity Billing Determinants" shall mean the total metered throughput, regardless of source, during the Computation Period, adjusted for known and measurable changes. Should the Company expect to purchase commodity gas from several suppliers, the company shall allocate to each supplier a percentage of the total metered throughput, regardless of source, during the Computation Period,

(Rule 1220-4-7-.01, continued)

adjusted for known and measurable changes. The percentage used to allocate among suppliers shall be based on historical takes during the Computation Period, if appropriate; otherwise it shall be based upon the best estimate of the Company.

(9) "Authority" shall mean Tennessee Regulatory Authority.

Authority: *T.C.A. §§65-2-102 and 65-4-104.* ***Administrative History:*** *Original rule filed October 29, 1993; effective March 1, 1994. Editorial changes made by the Secretary of State pursuant to Public Chapter 305 of 1995; "Commission" and references to the "Commission" were changed to "Authority" and references to the "Authority"; effective March 28, 2003.*

1220-4-7-.02 GENERAL PROVISIONS

(1) These Purchased Gas Adjustment (PGA) Rules are intended to permit the company to recover, in timely fashion, the total cost of gas purchased for delivery to its customers and to assure that the Company does not over-collect or under-collect Gas Costs from its customers.

(2) These Rules are intended to apply to all Gas Costs incurred in connection with the purchase, transportation and/or storage of gas purchased for general system supply, including, but not limited to, natural gas purchased from interstate pipeline transmission companies, producers, brokers, marketers, associations, intrastate pipeline transmission companies, joint ventures, providers of liquefied natural gas (LNG), liquefied petroleum gas (LPG), substitute, supplemental or synthetic natural gas (SNG), and other hydrocarbons used as feed-stock, other distribution companies and end-users, whether or not the Gas Costs are regulated by the Federal Energy Regulatory Commission and whether or not the provider of the gas, transportation or storage is affiliated with the Company.

(3) To the extent, practicable, any revision in the PGA shall be filed with the Authority no less than thirty (30) days in advance of the proposed effective date and shall be accompanied by the computations and information required by these Rules. It is recognized, however, that in many instances the Company receives less than thirty (30) days notice from its suppliers and that other conditions may exist which prevent the Company from providing thirty (30) days advance notice. Therefore, should circumstances occur where information necessary for the determination of an adjustment under these Rules is not available to the Company so that the thirty (30) days requirement can be met, the Authority may permit the Company to place rates into effect with shorter advance notice, upon good cause shown.

(4) The rates for gas service set forth in all of the Rate Schedules of the Company shall be adjusted pursuant to the terms of the PGA, or any specified portion of the PGA as determined by individual Rate Schedule(s).

(5) No provisions of these rules shall supersede any provision of a special contract approved by the Authority.

Authority: *T.C.A. §§65 -2-102 and 65-4-104.* ***Administrative History:*** *Original rule filed October 29, 1993; effective March 1, 1994. Editorial changes made by the Secretary of State pursuant to Public Chapter 305 of 1995; "Commission" and references to the "Commission" were changed to "Authority" and references to the "Authority"; effective March 28, 2003.*

1220-4-7-.03 COMPUTATIONS AND APPLICATION OF THE PURCHASED GAS ADJUSTMENT (PGA).

(1) The PGA shall consist of three major components: (a) the Gas Charge Adjustment; (b) the Refund Adjustment and (c) the Actual Cost Adjustment (ACA).

(Rule 1220-4-7-.03, continued)

(a) Computation of Gas Charge Adjustment. The Company shall compute the jurisdictional Gas Charge Adjustment at such time that the Company determines that there is a significant change in its Gas Costs.

1. Formulas. The following formulas shall be used to compute the Gas Charge Adjustment:

(i) Firm GCA =

$$\left(\left(\frac{D \pm DACA}{SF}\right) - DB\right) + \left(\left(\frac{P + T + SR \pm CACA}{ST}\right) - CB\right)$$

(ii) Non-Firm GCA

$$\left(\frac{P + T + SR \pm CACA}{ST}\right) - CB$$

2. Definitions of Formula Components.

(i) GCA = The Gas Charge Adjustment in dollars per Ccf/Therm, rounded to no more than five decimal places

(ii) D = The sum of all fixed Gas Costs.

(iii) DACA = The demand portion of the ACA.

(iv) P = The sum of all commodity/gas charges.

(v) T = The sum of all transportation charges.

(vi) SR = The sum of all FERC approved surcharges.

(vii) CACA = The commodity portion of the ACA.

(viii) DB = The per unit of demand costs or other fixed charges included in base rates in the most recently completed general rate case (which may be zero if the Company so elects and the Authority so approves.)

(ix) CB = The per unit rate of variable Gas Costs included in base rates in the most recently completed general rate case (which may be zero if the Company so elects and the Authority so approves).

(x) SF = Firm sales.

(xi) ST = Total sales.

3. Determination of Factors Gas Charge Adjustment.

(i) Demand Charges (Factor D)

All fixed Gas Costs that do not vary with the amount of gas purchased or transported, including, but not limited to, the product resulting from the multiplication of (1) the respective Demand Billing Determinants by (2) the respective supplier demand rates that are effective, known or reasonably anticipated at the time the PGA is filed with the Authority and (3) any fixed storage charges.

(ii) Demand Actual Cost Adjustment (Factor DACA)

See subsection (1)(c) Actual Cost Adjustment

(iii) Purchased Commodity Charges (Factor P)

All commodity or other variable gas costs associated with the amount of gas purchased or transported including, but not limited to, the product resulting from the multiplication of (1) the respective Demand Billing Determinants by (2) the respective supplier demand rates that are effective, known or reasonably anticipated at the time the PGA is filed with the Authority and (3) any fixed storage charges.

(iv) Transportation Charges (Factor T)

The transportation charges actually invoiced to the company during the Computation Period or expected to be involved in the Company during the current period.

(v) FERC Approved Surcharges (Factor SR)

The sum of all FERC approved surcharges, including gas inventory charges or its equivalent, actually invoiced or expected to be invoiced to the Company during the Computation Period or that are effective, known or reasonably anticipated at the time the PGA is filed with the Authority.

(vi) Actual Cost Adjustment (Factor ACA)

See subsection (1)(c) Actual Cost Adjustment.

(viii) Total Sales (Factor ST)

Total volumes billed to all the Company's customers during the Computation Period, regardless or source, adjusted for known measurable changes.

4. Modification of Formulas.

The formulas set forth above are not designed for use with two-part demand/commodity rate schedules; however, the formulas may be modified form time to time to carry out the intent of these PGA Rules. Any proposed modification to the formulas shall contain a proposed effective date. The Authority may suspend the modification within thirty (30) days of filing, in which case the proposed modification shall be subject to notice and hearing; otherwise, the modification to the formula shall be effective on the proposed effective date.

5. Filing with the Authority.

(i) The computation of the Gas Charge Adjustment shall be filed in accordance with the notice requirements specified in Rule 1220-4-7-.02(3) shall remain in effect until a revised Gas Charge Adjustment is computed and filed pursuant to these Rules.

(ii) The Company shall file with the Authority a transmittal letter, an exhibit showing the computation of the Gas Charge Adjustment, a PGA tariff sheet, and any applicable revised tariff sheets issued by suppliers. The transmittal letter shall state the PGA tariff sheet number, the service area(s), the primary reasons for revision, and the effective date.

(iii) If the Company proposes to recover any Gas Costs relating to (1) any payments to an affiliate or (2) any payments to a nonaffiliate for emergency gas, over-run charges, or (3) the payment of any demand or fixed charges in connection with an increase in contract demand, the Company must file with the Authority a statement setting forth the reasons why such charges were incurred and sufficient information to permit the Authority to determine if such payments were prudently made under the conditions which existed at the time the purchase decisions were made.

(iv) Any filing of a rate change under these Rules shall be effective on the proposed effective date unless the Authority shall act to suspend the proposed change within thirty (30) days after the filing, in which case the filing shall be subject to notice and hearing.

(b) Refund Adjustment. The Refund Adjustment shall be separately stated for firm and non-firm customers, and may be either positive or negative.

1. Computation of Refund Adjustment. The Company shall compute a Refund Adjustment on the last day of each calendar quarter using the following formulas:

(i) $$\text{Firm RA} = \left(\frac{\text{DR L - DR2}}{\text{SFR}}\right) + \left(\frac{\text{CR1 - CR2} \pm \text{CR3} \pm \text{i}}{\text{STR}}\right)$$

(ii) $$\text{Non-Firm RA} = \left(\frac{\text{CR1 - CR2} \pm \text{CR3} \pm \text{i}}{\text{STR}}\right)$$

2. Definitions of Formula Components.

(i) RA = the Refund Adjustment in dollars per Ccf/therm, rounded to no more than five decimal p1aces.

(ii) DRI = Demand refund not included in a currently effective Refund Adjustment and received from suppliers by check, wire transfer. or credit memo.

(iii) DR2 = a demand surcharge from a supplier not includable in the Gas Charge Adjustment, and not included in a currently effective refund adjustment.

(iv) CR1 = Commodity refund not included in a currently effective Refund Adjustment, and received form suppliers by check, wire transfer, or credit memo.

(v) CR2 = A commodity surcharge from a supplier not includable in the Gas Charge Adjustment, and not included in a currently effective Refund Adjustment.

(vi) CR3 = The residual balance of an expired Refund Adjustment.

(vii) I = Interest on the "Refund Due Customers' Account", using the average monthly balance based on the beginning and ending monthly balances. The interest rates for each calendar quarter used to compute such interest shall be a rate equal to the arithmetic mean (to the nearest one-hundredth of one percent) of the prime rate value published in the "Federal Reserve Bulletin" or in the Federal Reserve's "Selected Interest Rates" for the 4th, 3rd and 2nd months preceding the 1st month of the calendar quarter.

(viii) SFR = Firm sales as defined in the Gas Charge Adjustment computations, less sales under a transportation or negotiated rate schedule.

(ix) STR = Total sales as defined in the Gas Charge Adjustment computation, less sales under a transportation or negotiated rate schedule.

3. Modification of Formula. The formulas set forth above are not designed for use with two-part demand/commodity rate schedules; however, the formulas may be modified from time to time to carry out the intent of these PGA Rules. Any proposed modification to the formulas shall contain a proposed effective date. The Authority may suspend the modification within thirty (30) days of filing, in which case the proposed modification shall be subject to notice and hearing; otherwise, the modification to the formula shall be effective on the proposed effective date.

4. Filing with the Authority.

(i) The computation of the Refund adjustment shall be filed in accordance with the notice requirements specified in Rule 1220-4-7-.02(3) and shall remain in effect for a period of twelve (12) months or for such longer or shorter period of time as required to appropriately refund the applicable refund amount.

(ii) The company shall file with the Authority a transmittal letter, exhibits showing the computation of the Refund Adjustment and interest calculations, and a PGA tariff sheet. The transmittal letter shall state the PGA tariff sheet number, the service area(s), the reason for adjustment, and the effective date. Should the Company have a Gas Charge Adjustment filing to become effective the same date as a Refund Adjustment, a separate transmittal letter and PGA tariff sheet shall not be necessary.

(c) Actual Cost Adjustment.

1. Commencing with the initial effective date of these Rules, the Company shall calculate the ACA monthly. The Company shall be required to include the ACA in its calculation of the Gas Charge Adjustment at least monthly. Should the Company or Authority staff determine it appropriate to include the ACA in the Gas Charge Adjustment more frequently than once per year, then the company may be allowed/directed to do so. The Authority shall resolve disputes between the Company and the Staff regarding timing of such ACAs.

2. The ACA shall be the difference between (1) revenues billed customers by means of the Gas Charge Adjustment and (2) the cost of gas invoiced the Company by suppliers plus margin loss (if allowed by order of the Authority in another docket) as reflected in the Deferred Gas Cost account. The balance of said account shall be adjusted for interest at the rate provided for the calculation of interest with respect to the Refund Adjustment. The ACA shall be segregated into demand and commodity, and shall be added to or deducted from, as appropriate, the respective demand and commodity costs included in

the Gas Charge Adjustment. Supplemental sheets showing the calculations of margin losses and cost savings shall also be provided.

3. Adjustments to Prior Period ACAs. In the event that circumstances warrant a correction to or restatement of a prior period ACA, such correction or restatement shall be made in accordance with the ACA calculation in effect for the time period(s) to which the correction or restatement relates. The resulting adjustment shall then be added to or deducted from the appropriate ACA in the next ensuing ACA filing with the Authority.

(2) Annual Filing with the Authority. Each year, the Company shall file with the Authority an annual report reflecting the transactions in the Deferred Gas Cost Account. Unless the Authority provides written notification to the Company within one hundred eighty (180) days from the date of filing the report, the Deferred Gas Cost Adjustment Account shall be deemed in compliance with the provisions of these Rules. This 180 day notification period may be extended by mutual consent of the Company and the Authority Staff or by order of the Authority.

Authority: *T.C.A. §§65-2-102 and 65-4-104.* ***Administrative History:*** *Original rule filed October 29, 1993; effective March 1, 1994. Editorial changes made by the Secretary of State pursuant to Public Chapter 305 of 1995; "Commission" and references to the "Commission" were changed to "Authority" and references to the "Authority"; effective March 28, 2003.*

1220-4-7-.04 GAS COST ACCOUNTING. To appropriately match revenues with cost of purchased gas as contemplated under these Rules, the Company shall originally record the cost of purchased gas in a "Deferred Gas Cost" account. Monthly, the Company shall debit "Natural Gas Purchases" with an amount equal to any gas cost component included in the Company's base tariff rates (base rate) plus the PGA rate, as calculated hereunder, multiplied by the appropriate volumes sold or billed to customers. The corresponding monthly credit entry shall be made to the "Deferred Gas Cost" account.

Authority: *T.C.A. §§65-2-102 and 65-4-104.* ***Administrative History:*** *Original rule filed October 29, 1993; effective March 1, 1994.*

1220-4-7-.05 AUDIT OF PRUDENCE OF GAS PURCHASES.

(1) The audit of prudence of gas purchases shall apply to Class A gas companies only. Class A gas company shall mean a local gas distribution company having annual gas operating revenues of two million five hundred thousand dollars ($2,500,000) or more.

(a) Unless otherwise ordered by the Authority, the Staff and the LDCs shall prepare and issue a request for proposals and after reviewing the proposals, recommend to the Authority a qualified consultant to evaluate and report annually on the prudence of any gas costs included in the PGA. Subject to the approval of the Authority, a contract to perform the audit shall be awarded to the consultant to cover at least two consecutive annual audits.

1. The scope of the evaluation shall be agreed to by the Staff and the LDCs and shall include guidelines to be used by the consultant in performing any such prudence review.

2. Before selecting a consultant, the Staff and the LDCs shall determine the maximum amount to be paid for the audits that will be included in thc contract. Each LDC shall pay to the consultant an equal portion of the cost of the audit(s).

3. The amount paid to the consultant by an LDC shall be recorded in the LDC's Deferred Gas Cost Account and shall be recovered through the procedures set forth in these PGA rules.

(b) Each LDC shall file a non-binding gas purchase plan with the Authority at least annually.

(Rule 1220-4-7-.05, continued)

1. An LDC may, at its option, update the plan whenever it deems appropriate.

2. The gas purchase plan shall include a general statement of the company's gas purchasing policies (*e.g.*, the consideration given by the Company to the cost of gas, the security of the gas supply, the ability to obtain deliverability of the gas and other factors deemed relevant by the Company) which are established under the guidelines adopted under subsection (1)(a) of this Rule.

3. All such plans shall be confidential and may be filed under appropriate protective orders.

(c) In connection with the filing of the annual report of transactions in the Deferred Gas Cost Account required by Rule 1220-4-7-.03(2), each Class A LDC shall file a summary report detailing its gas purchasing practice during the period covered by the annual report. This requirement may be satisfied by the inclusion of such summary report information in the consultant's report that is required under section (1) of this Rule.

1. Within ninety (90) days after receipt of the gas purchase practices report information and the consultant's report, the Authority, in its discretion, may order a hearing to review the prudence of an LDC's gas purchasing practices and subject to the hearing, order the LDC to refund any imprudent gas costs collected under the provisions of the PGA Rules during the annual period under review. Any such order shall be subject to appeal in accordance with applicable law.

(3) If the Authority does not order a hearing within the ninety (90) day period, the LDC gas purchasing practices shall be deemed prudent.

Authority: *T.C.A. §§65 -2-102 and 65-4-104.* ***Administrative History:*** *Original rule filed October 29, 1993; effective March 1, 1994. Editorial changes made by the Secretary of State pursuant to Public Chapter 305 of 1995; "Commission" and references to the "Commission" were changed to "Authority" and references to the "Authority"; effective March 28, 2003.*

RULES
OF
TENNESSEE REGULATORY AUTHORITY
DIVISION OF PUBLIC UTILITIES

CHAPTER 1220-4-7
PURCHASED GAS ADJUSTMENT RULES

TABLE OF CONTENTS

1220-4-7-.01 DEFINITIONS.

(1) "Gas Costs" shall mean the total delivered cost of gas paid or to be paid to Suppliers, including, but not limited to, all commodity/gas charges, demand charges, peaking charges, surcharges, emergency gas purchases, over-run charges, capacity charges, standby charges, gas inventory charges, minimum bill charges, minimum take charges, take-or-pay charges and take-and-pay charges, storage charges, service fees and transportation charges and any other similar charges which are paid by the Company to its gas suppliers in connection with the purchase, storage or transportation of gas for the Company's system supply.

(2) "Company" or "LDC" shall mean local gas distribution company regulated by the Tennessee Regulatory Authority.

(3) "Fixed Gas Costs" shall mean all Gas Costs based on the Company's right to demand gas or transportation on a daily or seasonal peak; but unless otherwise ordered by the Authority, shall not include other charges paid for gas reserve dedication (*e.g.*, reservation fees and gas inventory charges), minimum bill charges, minimum take charges, overrun charges. Emergency gas charges, take-or-pay and take-and-pay charges (all of which shall be considered commodity costs).

(4) "Gas Charge Adjustment' shall mean the per unit amount billed by the Company to its customers solely for Gas Costs. The Gas Charge Adjustment shall be separately stated for firm customers and for non-firm customers.

(5) "Suppliers" shall mean any person or entity, including affiliates of the Company, who locates, purchases, sells, stores and/or transports natural gas or its equivalent for or on behalf of the Company. Suppliers may include, but not be limited to interstate pipeline transmission companies, producers, brokers, marketers, associations, intrastate pipeline transmission companies, joint ventures, providers of liquefied natural gas (LNG), liquefied petroleum gas (LPG), substitute, supplemental or synthetic natural gas (SNG), and other hydrocarbons used as feed-stock, other distribution companies and end-users.

(6) "Computation Period" shall mean the twelve (12) month period utilized to compute Gas Costs. Such period shall be the twelve (12) month period ending on the last day of a month which is no more than 62 days prior to the filing date of a Purchased Gas Adjustment (PGA).

(7) "Demand Billing Determinants" shall mean the annualized volumes for which the Company has contracted with Suppliers as of the first day of the Filing Month.

(8) "Commodity Billing Determinants" shall mean the total metered throughput, regardless of source, during the Computation Period, adjusted for known and measurable changes. Should the Company expect to purchase commodity gas from several suppliers, the company shall allocate to each supplier a percentage of the total metered throughput, regardless of source, during the Computation Period,

adjusted for known and measurable changes. The percentage used to allocate among suppliers shall be based on historical takes during the Computation Period, if appropriate; otherwise it shall be based upon the best estimate of the Company.

(9) "Authority" shall mean Tennessee Regulatory Authority.

Authority: *T.C.A. §§65-2-102 and 65-4-104.* ***Administrative History:*** *Original rule filed October 29, 1993; effective March 1, 1994. Editorial changes made by the Secretary of State pursuant to Public Chapter 305 of 1995; "Commission" and references to the "Commission" were changed to "Authority" and references to the "Authority"; effective March 28, 2003.*

1220-4-7-.02 GENERAL PROVISIONS

(1) These Purchased Gas Adjustment (PGA) Rules are intended to permit the company to recover, in timely fashion, the total cost of gas purchased for delivery to its customers and to assure that the Company does not over-collect or under-collect Gas Costs from its customers.

(2) These Rules are intended to apply to all Gas Costs incurred in connection with the purchase, transportation and/or storage of gas purchased for general system supply, including, but not limited to, natural gas purchased from interstate pipeline transmission companies, producers, brokers, marketers, associations, intrastate pipeline transmission companies, joint ventures, providers of liquefied natural gas (LNG), liquefied petroleum gas (LPG), substitute, supplemental or synthetic natural gas (SNG), and other hydrocarbons used as feed-stock, other distribution companies and end-users, whether or not the Gas Costs are regulated by the Federal Energy Regulatory Commission and whether or not the provider of the gas, transportation or storage is affiliated with the Company.

(3) To the extent, practicable, any revision in the PGA shall be filed with the Authority no less than thirty (30) days in advance of the proposed effective date and shall be accompanied by the computations and information required by these Rules. It is recognized, however, that in many instances the Company receives less than thirty (30) days notice from its suppliers and that other conditions may exist which prevent the Company from providing thirty (30) days advance notice. Therefore, should circumstances occur where information necessary for the determination of an adjustment under these Rules is not available to the Company so that the thirty (30) days requirement can be met, the Authority may permit the Company to place rates into effect with shorter advance notice, upon good cause shown.

(4) The rates for gas service set forth in all of the Rate Schedules of the Company shall be adjusted pursuant to the terms of the PGA, or any specified portion of the PGA as determined by individual Rate Schedule(s).

(5) No provisions of these rules shall supersede any provision of a special contract approved by the Authority.

Authority: *T.C.A. §§65 -2-102 and 65-4-104.* ***Administrative History:*** *Original rule filed October 29, 1993; effective March 1, 1994. Editorial changes made by the Secretary of State pursuant to Public Chapter 305 of 1995; "Commission" and references to the "Commission" were changed to "Authority" and references to the "Authority"; effective March 28, 2003.*

1220-4-7-.03 COMPUTATIONS AND APPLICATION OF THE PURCHASED GAS ADJUSTMENT (PGA).

(1) The PGA shall consist of three major components: (a) the Gas Charge Adjustment; (b) the Refund Adjustment and (c) the Actual Cost Adjustment (ACA).

(Rule 1220-4-7-.03, continued)

(a) Computation of Gas Charge Adjustment. The Company shall compute the jurisdictional Gas Charge Adjustment at such time that the Company determines that there is a significant change in its Gas Costs.

1. Formulas. The following formulas shall be used to compute the Gas Charge Adjustment:

(i) Firm GCA =

$$\left(\left(\frac{D \pm DACA}{SF}\right) - DB\right) + \left(\left(\frac{P + T + SR \pm CACA}{ST}\right) - CB\right)$$

(ii) Non-Firm GCA

$$\left(\frac{P + T + SR \pm CACA}{ST}\right) - CB$$

2. Definitions of Formula Components.

(i) GCA = The Gas Charge Adjustment in dollars per Ccf/Therm, rounded to no more than five decimal places

(ii) D = The sum of all fixed Gas Costs.

(iii) DACA = The demand portion of the ACA.

(iv) P = The sum of all commodity/gas charges.

(v) T = The sum of all transportation charges.

(vi) SR = The sum of all FERC approved surcharges.

(vii) CACA = The commodity portion of the ACA.

(viii) DB = The per unit of demand costs or other fixed charges included in base rates in the most recently completed general rate case (which may be zero if the Company so elects and the Authority so approves.)

(ix) CB = The per unit rate of variable Gas Costs included in base rates in the most recently completed general rate case (which may be zero if the Company so elects and the Authority so approves).

(x) SF = Firm sales.

(xi) ST = Total sales.

3. Determination of Factors Gas Charge Adjustment.

(i) Demand Charges (Factor D)

All fixed Gas Costs that do not vary with the amount of gas purchased or transported, including, but not limited to, the product resulting from the multiplication of (1) the respective Demand Billing Determinants by (2) the respective supplier demand rates that are effective, known or reasonably anticipated at the time the PGA is filed with the Authority and (3) any fixed storage charges.

(ii) Demand Actual Cost Adjustment (Factor DACA)

See subsection (1)(c) Actual Cost Adjustment

(iii) Purchased Commodity Charges (Factor P)

All commodity or other variable gas costs associated with the amount of gas purchased or transported including, but not limited to, the product resulting from the multiplication of (1) the respective Demand Billing Determinants by (2) the respective supplier demand rates that are effective, known or reasonably anticipated at the time the PGA is filed with the Authority and (3) any fixed storage charges.

(iv) Transportation Charges (Factor T)

The transportation charges actually invoiced to the company during the Computation Period or expected to be involved in the Company during the current period.

(v) FERC Approved Surcharges (Factor SR)

The sum of all FERC approved surcharges, including gas inventory charges or its equivalent, actually invoiced or expected to be invoiced to the Company during the Computation Period or that are effective, known or reasonably anticipated at the time the PGA is filed with the Authority.

(vi) Actual Cost Adjustment (Factor ACA)

See subsection (1)(c) Actual Cost Adjustment.

(viii) Total Sales (Factor ST)

Total volumes billed to all the Company's customers during the Computation Period, regardless or source, adjusted for known measurable changes.

4. Modification of Formulas.

The formulas set forth above are not designed for use with two-part demand/commodity rate schedules; however, the formulas may be modified form time to time to carry out the intent of these PGA Rules. Any proposed modification to the formulas shall contain a proposed effective date. The Authority may suspend the modification within thirty (30) days of filing, in which case the proposed modification shall be subject to notice and hearing; otherwise, the modification to the formula shall be effective on the proposed effective date.

5. Filing with the Authority.

(i) The computation of the Gas Charge Adjustment shall be filed in accordance with the notice requirements specified in Rule 1220-4-7-.02(3) shall remain in effect until a revised Gas Charge Adjustment is computed and filed pursuant to these Rules.

(ii) The Company shall file with the Authority a transmittal letter, an exhibit showing the computation of the Gas Charge Adjustment, a PGA tariff sheet, and any applicable revised tariff sheets issued by suppliers. The transmittal letter shall state the PGA tariff sheet number, the service area(s), the primary reasons for revision, and the effective date.

(iii) If the Company proposes to recover any Gas Costs relating to (1) any payments to an affiliate or (2) any payments to a nonaffiliate for emergency gas, over-run charges, or (3) the payment of any demand or fixed charges in connection with an increase in contract demand, the Company must file with the Authority a statement setting forth the reasons why such charges were incurred and sufficient information to permit the Authority to determine if such payments were prudently made under the conditions which existed at the time the purchase decisions were made.

(iv) Any filing of a rate change under these Rules shall be effective on the proposed effective date unless the Authority shall act to suspend the proposed change within thirty (30) days after the filing, in which case the filing shall be subject to notice and hearing.

(b) Refund Adjustment. The Refund Adjustment shall be separately stated for firm and non-firm customers, and may be either positive or negative.

1. Computation of Refund Adjustment. The Company shall compute a Refund Adjustment on the last day of each calendar quarter using the following formulas:

(i) $$\text{Firm RA} = \left(\frac{DR\,L - DR2}{SFR}\right) + \left(\frac{CR1 - CR2 \pm CR3 \pm i}{STR}\right)$$

(ii) $$\text{Non-Firm RA} = \left(\frac{CR1 - CR2 \pm CR3 \pm i}{STR}\right)$$

2. Definitions of Formula Components.

(i) RA = the Refund Adjustment in dollars per Ccf/therm, rounded to no more than five decimal p1aces.

(ii) DRI = Demand refund not included in a currently effective Refund Adjustment and received from suppliers by check, wire transfer. or credit memo.

(iii) DR2 = a demand surcharge from a supplier not includable in the Gas Charge Adjustment, and not included in a currently effective refund adjustment.

(iv) CR1 = Commodity refund not included in a currently effective Refund Adjustment, and received form suppliers by check, wire transfer, or credit memo.

(v) CR2 = A commodity surcharge from a supplier not includable in the Gas Charge Adjustment, and not included in a currently effective Refund Adjustment.

(vi) CR3 = The residual balance of an expired Refund Adjustment.

(vii) I = Interest on the "Refund Due Customers' Account", using the average monthly balance based on the beginning and ending monthly balances. The interest rates for each calendar quarter used to compute such interest shall be a rate equal to the arithmetic mean (to the nearest one-hundredth of one percent) of the prime rate value published in the "Federal Reserve Bulletin" or in the Federal Reserve's "Selected Interest Rates" for the 4th, 3rd and 2nd months preceding the 1st month of the calendar quarter.

(viii) SFR = Firm sales as defined in the Gas Charge Adjustment computations, less sales under a transportation or negotiated rate schedule.

(ix) STR = Total sales as defined in the Gas Charge Adjustment computation, less sales under a transportation or negotiated rate schedule.

3. Modification of Formula. The formulas set forth above are not designed for use with two-part demand/commodity rate schedules; however, the formulas may be modified from time to time to carry out the intent of these PGA Rules. Any proposed modification to the formulas shall contain a proposed effective date. The Authority may suspend the modification within thirty (30) days of filing, in which case the proposed modification shall be subject to notice and hearing; otherwise, the modification to the formula shall be effective on the proposed effective date.

4. Filing with the Authority.

(i) The computation of the Refund adjustment shall be filed in accordance with the notice requirements specified in Rule 1220-4-7-.02(3) and shall remain in effect for a period of twelve (12) months or for such longer or shorter period of time as required to appropriately refund the applicable refund amount.

(ii) The company shall file with the Authority a transmittal letter, exhibits showing the computation of the Refund Adjustment and interest calculations, and a PGA tariff sheet. The transmittal letter shall state the PGA tariff sheet number, the service area(s), the reason for adjustment, and the effective date. Should the Company have a Gas Charge Adjustment filing to become effective the same date as a Refund Adjustment, a separate transmittal letter and PGA tariff sheet shall not be necessary.

(c) Actual Cost Adjustment.

1. Commencing with the initial effective date of these Rules, the Company shall calculate the ACA monthly. The Company shall be required to include the ACA in its calculation of the Gas Charge Adjustment at least monthly. Should the Company or Authority staff determine it appropriate to include the ACA in the Gas Charge Adjustment more frequently than once per year, then the company may be allowed/directed to do so. The Authority shall resolve disputes between the Company and the Staff regarding timing of such ACAs.

2. The ACA shall be the difference between (1) revenues billed customers by means of the Gas Charge Adjustment and (2) the cost of gas invoiced the Company by suppliers plus margin loss (if allowed by order of the Authority in another docket) as reflected in the Deferred Gas Cost account. The balance of said account shall be adjusted for interest at the rate provided for the calculation of interest with respect to the Refund Adjustment. The ACA shall be segregated into demand and commodity, and shall be added to or deducted from, as appropriate, the respective demand and commodity costs included in

the Gas Charge Adjustment. Supplemental sheets showing the calculations of margin losses and cost savings shall also be provided.

3. Adjustments to Prior Period ACAs. In the event that circumstances warrant a correction to or restatement of a prior period ACA, such correction or restatement shall be made in accordance with the ACA calculation in effect for the time period(s) to which the correction or restatement relates. The resulting adjustment shall then be added to or deducted from the appropriate ACA in the next ensuing ACA filing with the Authority.

(2) Annual Filing with the Authority. Each year, the Company shall file with the Authority an annual report reflecting the transactions in the Deferred Gas Cost Account. Unless the Authority provides written notification to the Company within one hundred eighty (180) days from the date of filing the report, the Deferred Gas Cost Adjustment Account shall be deemed in compliance with the provisions of these Rules. This 180 day notification period may be extended by mutual consent of the Company and the Authority Staff or by order of the Authority.

Authority: *T.C.A. §§65-2-102 and 65-4-104.* ***Administrative History:*** *Original rule filed October 29, 1993; effective March 1, 1994. Editorial changes made by the Secretary of State pursuant to Public Chapter 305 of 1995; "Commission" and references to the "Commission" were changed to "Authority" and references to the "Authority"; effective March 28, 2003.*

1220-4-7-.04 GAS COST ACCOUNTING. To appropriately match revenues with cost of purchased gas as contemplated under these Rules, the Company shall originally record the cost of purchased gas in a "Deferred Gas Cost" account. Monthly, the Company shall debit "Natural Gas Purchases" with an amount equal to any gas cost component included in the Company's base tariff rates (base rate) plus the PGA rate, as calculated hereunder, multiplied by the appropriate volumes sold or billed to customers. The corresponding monthly credit entry shall be made to the "Deferred Gas Cost" account.

Authority: *T.C.A. §§65-2-102 and 65-4-104.* ***Administrative History:*** *Original rule filed October 29, 1993; effective March 1, 1994.*

1220-4-7-.05 AUDIT OF PRUDENCE OF GAS PURCHASES.

(1) The audit of prudence of gas purchases shall apply to Class A gas companies only. Class A gas company shall mean a local gas distribution company having annual gas operating revenues of two million five hundred thousand dollars ($2,500,000) or more.

(a) Unless otherwise ordered by the Authority, the Staff and the LDCs shall prepare and issue a request for proposals and after reviewing the proposals, recommend to the Authority a qualified consultant to evaluate and report annually on the prudence of any gas costs included in the PGA. Subject to the approval of the Authority, a contract to perform the audit shall be awarded to the consultant to cover at least two consecutive annual audits.

1. The scope of the evaluation shall be agreed to by the Staff and the LDCs and shall include guidelines to be used by the consultant in performing any such prudence review.

2. Before selecting a consultant, the Staff and the LDCs shall determine the maximum amount to be paid for the audits that will be included in thc contract. Each LDC shall pay to the consultant an equal portion of the cost of the audit(s).

3. The amount paid to the consultant by an LDC shall be recorded in the LDC's Deferred Gas Cost Account and shall be recovered through the procedures set forth in these PGA rules.

(b) Each LDC shall file a non-binding gas purchase plan with the Authority at least annually.

(Rule 1220-4-7-.05, continued)

1. An LDC may, at its option, update the plan whenever it deems appropriate.

2. The gas purchase plan shall include a general statement of the company's gas purchasing policies (*e.q.*, the consideration given by the Company to the cost of gas, the security of the gas supply, the ability to obtain deliverability of the gas and other factors deemed relevant by the Company) which are established under the guidelines adopted under subsection (1)(a) of this Rule.

3. All such plans shall be confidential and may be filed under appropriate protective orders.

(c) In connection with the filing of the annual report of transactions in the Deferred Gas Cost Account required by Rule 1220-4-7-.03(2), each Class A LDC shall file a summary report detailing its gas purchasing practice during the period covered by the annual report. This requirement may be satisfied by the inclusion of such summary report information in the consultant's report that is required under section (1) of this Rule.

1. Within ninety (90) days after receipt of the gas purchase practices report information and the consultant's report, the Authority, in its discretion, may order a hearing to review the prudence of an LDC's gas purchasing practices and subject to the hearing, order the LDC to refund any imprudent gas costs collected under the provisions of the PGA Rules during the annual period under review. Any such order shall be subject to appeal in accordance with applicable law.

(3) If the Authority does not order a hearing within the ninety (90) day period, the LDC gas purchasing practices shall be deemed prudent.

Authority: *T.C.A. §§65 -2-102 and 65-4-104.* ***Administrative History:*** *Original rule filed October 29, 1993; effective March 1, 1994. Editorial changes made by the Secretary of State pursuant to Public Chapter 305 of 1995; "Commission" and references to the "Commission" were changed to "Authority" and references to the "Authority"; effective March 28, 2003.*

PURCHASED GAS ADJUSTMENT PROVISION PURSUANT TO RULE 401.12 OF THE TENNESSEE REGULATORY AUTHORITY RULES AND REGULATIONS

I. GENERAL PROVISIONS

A. This Purchased Gas Adjustment (PGA) Rider is intended to permit the Company to recover, in a timely fashion, the total cost of gas purchased for delivery to its customers and to assure that the Company does not over-collect or under-collect Gas Costs from its customers.

B. This Rider is intended to apply to all Gas Costs incurred in connection with the purchase, transportation and/or storage of gas purchased for general system supply, including, but not limited to, natural gas purchased from interstate pipeline transmission companies, producers, brokers, marketers, associations, intrastate pipeline transmission companies, joint ventures, providers of liquefied natural gas (LNG), liquefied petroleum gas (LPG), substitute, supplemental or synthetic natural gas (SNG), and other hydrocarbons used as feed-stock, other distribution companies and end-users, whether or not the Gas Costs are regulated by the Federal Energy Regulatory Authority and whether or not the provider of the gas, transportation or storage is affiliated with the Company.

C. To the extent practicable, any revision in the PGA shall be filed with the Authority no less than thirty (30) days in advance of the proposed effective date and shall be accompanied by the computations and information required by this Rider. It is recognized, however, that in many instances the Company receives less than 30 days notice from its Suppliers and that other conditions may exist which may prevent the Company from providing 30 days advance notice. Therefore, should circumstances occur where information necessary for the determination of an adjustment under this Rider is not available to the Company so that the thirty (30) days requirement may be met, the Company may, upon good cause shown, be permitted to place such rates into effect with shorter advance notice.

D. The rates for gas service set forth in all of the Rate Schedules of the Company shall be adjusted pursuant to the terms of the PGA, or any specified portion of the PGA as determined by individual Rate Schedule(s).

D. No provision of this Rider shall supersede any provision of a Special Contract approved by the Authority.

II. DEFINITIONS

A. "**Gas Costs**" shall mean the total delivered cost of gas paid or to be paid to Suppliers, including, but not limited to, all commodity/gas charges, demand charges, peaking charges, surcharges, emergency gas purchases, over-run charges, capacity charges, standby charges, gas inventory charges, minimum bill charges, minimum take charges, take-or-pay charges and take-and-pay charges (except as provided below), storage charges, service fees and transportation charges and any other similar charges which are paid by the Company to its gas suppliers in connection with the purchase, storage or transportation of gas for the Company's system supply.

B. "**Fixed Gas Costs**" shall mean all Gas Costs based on the Company's right to demand gas or transportation on a daily or seasonal peak; but unless otherwise ordered by the Authority, shall not include other charges paid for gas reserve dedication (e.g., reservation fees and gas inventory charges), minimum bill charges, minimum take charges, over-run charges, emergency gas charges, take-or-pay charges or take-and-pay charges (all of which shall be considered commodity costs).

PURCHASED GAS ADJUSTMENT PROVISION (Continued)

C. “ **Gas Charge Adjustment**” shall mean the per unit amount billed by the Company to its customers solely for Gas Costs. The Gas Charge Adjustment shall be separately stated for firm customers and for non-firm customers.

D. “ **Suppliers**” shall mean any person or entity, including affiliates of the Company, who locates, purchases, sells, stores and/or transports natural gas or its equivalent for or on behalf of the Company. Suppliers may include, but not be limited to, interstate pipeline transmission companies, producers, brokers, marketers, associations, intrastate pipeline transmission companies, joint ventures, providers of LNG, LPG, SNG, and other hydrocarbons used as feed-stock, other distribution companies and end-users.

E. “ **Computation Period**" shall mean the twelve (12) month period utilized to compute Gas Costs. Such period shall be the twelve (12) month period ending on the last day of a month which is no more than 62 days prior to the filing date of a PGA.

F. “ **Demand Billing Determinants**” shall mean the annualized volumes for which the Company has contracted with Suppliers as of the first day of the Filing Month.

G. “ **Commodity Billing Determinants**” shall mean the total metered throughput, regardless of source, during the Computation Period, adjusted for known and measurable changes. Should the Company expect to purchase commodity gas from several Suppliers, the Company shall allocate to each supplier a percentage of the total metered throughput, regardless of source, during the Computation Period, adjusted for known and measurable changes. The percentage used to allocate among Suppliers shall be based on historical takes during the Computation Period, if appropriate; otherwise it shall be based upon the best estimate of the Company.

H. “ **Filing Month**” shall mean the month in which a proposed revision is to become effective.

III. COMPUTATION AND APPLICATION OF THE PGA

The PGA shall consist of three major components: (1) the Gas Charge Adjustment; (2) the Refund Adjustment; and (3) the Actual Cost Adjustment (ACA).

A. Computation of Gas Charge Adjustment.

The Company shall compute the jurisdictional Gas Charge Adjustment at such time that the Company determines that there is a significant change in its Gas Costs.

1. **Formulas**. The following formulas shall be used to compute the Gas Charge

$$FirmGCA = \left[\left(\frac{D \pm DACA}{SF}\right) - DB\right] + \left[\left(\frac{P + T + SR \pm CACA}{ST}\right) - CB\right]$$

$$Non - FirmGCA = \left(\frac{P + T + SR \pm CACA}{ST}\right) - CB$$

PURCHASED GAS ADJUSTMENT PROVISION (Continued)

2. **Definitions of Formula Components.**

GCA	=	The Gas Charge Adjustment in dollars per CCF/Therm, rounded to no more than five decimal places.
D	=	The sum of all fixed Gas Costs.
DACA	=	The demand portion of the ACA.
P	=	The sum of all commodity/gas charges.
T	=	The sum of all transportation charges.
SR	=	The sum of all FERC approved surcharges.
CACA	=	The commodity portion of the ACA.
DB	=	The per unit rate of demand costs or other fixed charges included in base rates in the most recently completed general rate case (which may be zero if the Company so elects and the Authority so approves).
CB	=	The per unit rate of variable Gas Costs included in base rates in the most recently completed general rate case (which may be zero if the Company so elects and the Authority so approves).
SF	=	Firm sales.
ST	=	Total sales.

3. **Determination of Factors for Gas Charge Adjustment.**

a. **Demand Charges (Factor D)**

All fixed Gas Costs that do not vary with the amount of gas purchased or transported, including, but not limited to, the product resulting from the multiplication of (1) the respective Demand Billing Determinants by (2) the demand rates effective the first day of the Filing Month and (3) any fixed storage charges.

b. **Demand Actual Cost Adjustment (Factor DACA)**

See Subsection C of Section III.

PURCHASED GAS ADJUSTMENT PROVISION (Continued)

c. **Purchased Commodity Charges (Factor P)**

All commodity or other variable gas costs associated with the amount of gas purchased or transported including, but not limited to, the product resulting from the multiplication of (1) the respective Commodity Billing Determinants by (2) the respective supplier's commodity/gas rate which are known, or if not known which are reasonably anticipated, to be in effect on the first day of the Filing Month.

d. **Transportation Charge (Factor T)**
The transportation charges actually invoiced to the Company during the Computation Period or expected to be invoiced to the Company during the current period.

e. **FERC Approved Surcharges (Factor SR)**
The sum of all FERC approved surcharges, including gas inventory charges or its equivalent, actually invoiced or expected to be invoiced to the Company during the Computation Period or to be effective the first day of the Filing Month by respective Suppliers.

f. **Annual Cost Adjustment (Factor ACA)**
See Subsection C of Section III.

g. **Firm Sales (Factor SF)**
Total volumes billed to the Company's firm customers during the Computation Period, regardless of source, adjusted for known and measurable changes.

h. **Total Sales (Factor ST)**
Total volumes billed to all the Company's customers during the Computation Period, regardless of source, adjusted for known measurable changes.

4. Modification of Formulas.

The formulas set forth above are not designed for use with two-part demand/commodity rate schedules; therefore, the formulas may be modified for use with such rate schedules. In addition, the formulas may be modified from time to time to carry out the intent of this PGA Rider. Any amendment to the formulas shall be effective on the proposed effective date of the amendment unless the Authority shall act to suspend the proposed amendment within thirty days after the filing of the proposed amendment, in which case the proposed amendment shall be subject to notice and hearing.

PURCHASED GAS ADJUSTMENT PROVISION (Continued)

5. **Filing with the Authority.**
The computation of the Gas Charge Adjustment shall be filed in accordance with the notice requirements specified in Subsection C of Section I of this Rider, and shall remain in effect until a revised Gas Charge Adjustment is computed and filed pursuant to this Rider.

The Company shall file with the Authority a transmittal letter, an exhibit showing the computation of the Gas Charge Adjustment, a PGA tariff sheet, and any applicable revised tariff sheets issued by Suppliers.

The transmittal letter shall state the PGA tariff sheet number, the service area(s), the primary reasons for revision, and the effective date.

If the Company proposes to recover any Gas Costs relating to (1) any payments to an affiliate or (2) any payments to a non-affiliate for emergency gas, over-run charges, take-or-pay charges, and take-and-pay charges (except as provided below) or (3) the payment of any demand or fixed charges in connection with an increase in contract demand, the Company must file with the Authority a statement setting forth the reasons why such charges were incurred and sufficient information to permit the Authority to determine if such payments were prudently made under the conditions which existed at the time the purchase decisions were made.

Any filing of a rate change under this Rider shall be effective on the proposed effective date unless the Authority shall act to suspend the proposed change within thirty days after the filing, in which case the filing shall be subject to notice and hearing.

The recovery of pipeline take-or-pay charges which were the subject of Docket No. U-87-7590 shall continue to be handled under procedures approved by this Authority in that docket until such time as such procedures may be modified or amended by further order of the Authority.

B. Refund Adjustment.
The Refund Adjustment shall be separately stated for firm and non-firm customers, and may be either positive or negative.

1. **Computation of Refund Adjustment**
The Company shall compute a Refund Adjustment on the last day of each calendar quarter using the following formulas:

$$FirmRA = \left(\frac{DR1 - DR2}{SFR}\right) + \left(\frac{CR!{-}CR2 \pm CR3 \pm i}{STR}\right)$$

$$Non - FirmRA = \left(\frac{CR1 - CR2 \pm CR3 \pm i}{STR}\right)$$

PURCHASED GAS ADJUSTMENT PROVISION (Continued)

2. Definitions of Formula Components.

RA	=	The Refund Adjustment in dollars per CCF/therm, rounded to no more than five decimal places
DRI	=	Demand refund not included in a currently effective Refund Adjustment, and received from Suppliers by check, wire transfer, or credit memo.
DR2	=	A demand surcharge from a Supplier not includable in the Gas Charge Adjustment, and not included in a currently effective Refund Adjustment.
CRI	=	Commodity refund not included in a currently effective Refund Adjustment, and received from Suppliers by check, wire transfer, or credit memo.
CR2	=	A commodity surcharge from a supplier not includable in the Gas Charge Adjustment, and not included in a currently effective Refund Adjustment.
CR3	=	The residual balance of an expired Refund Adjustment.
i	=	Interest on the " Refund Due Customers' Account," using the average monthly balance based on the beginning and ending monthly balances. The interest rates for each calendar quarter used to compute such interest shall be a rate 2% below the arithmetic mean (to the nearest one-hundredth of one percent) of the prime rate value published in the " Federal Reserve Bulletin" or in the Federal Reserve's " Selected Interest Rates" for the 4th, 3rd, and 2nd months preceding the 1st month of the calendar quarter. The interest rate used shall not be greater than 12% nor less than 8%.
SFR	=	Firm sales as defined in the Gas Charge Adjustment computation, less sales under a transportation or negotiated rate schedule.
STR	=	Total sales as defined in the Gas Charge Adjustment computation, less sales under a transportation or negotiated rate schedule.

3. Modification of Formula.

The formulas set forth above are not designed for use with two-part demand/commodity rate schedules; therefore, the formulas may be modified for use with such rate schedules. In addition, the formulas may be modified from time to time to carry out the intent of this PGA Rider. Any amendment to the formulas shall be effective on the proposed effective date of the amendment unless the Authority shall act to suspend the proposed amendment within thirty days after the filing of the proposed amendment, in which case the proposed amendment shall be subject to notice and hearing.

PURCHASED GAS ADJUSTMENT PROVISION (Continued)

4. **Filing with the Authority.**
The computation of the Refund Adjustment shall be filed in accordance with the notice requirements specified in Subsection C of Section I this Rider, and shall remain in effect for a period of twelve (12) months or for such longer or shorter period of time as required to appropriately refund the applicable refund amount.

The Company shall file with the Authority a transmittal letter, exhibits showing the computation of the Refund Adjustment and interest calculations, and a PGA tariff sheet. The transmittal letter shall state the PGA tariff sheet number, the service area(s), the reason for adjustment, and the effective date. Should the Company have a Gas Charge Adjustment filing to become effective the same date as a Refund Adjustment, a separate transmittal letter and PGA tariff sheet shall not be necessary.

C. **Actual Cost Adjustment.**

Commencing with the initial effective date of this Rider, the Company shall calculate the ACA monthly. The Company may, at its option, file monthly to include the ACA in its calculation of the Gas Charge Adjustment but shall be required to do so at least annually. The ACA shall be the difference between (1) revenues billed customers by means of the Gas Charge Adjustment and (2) the cost of gas invoiced the Company by Suppliers plus margin loss (if allowed by order of the Authority in another docket) as reflected in the Deferred Gas Cost account. The balance of said account shall be adjusted for interest at the rate provided for the calculation of interest with respect to the Refund Adjustment. The ACA shall be segregated into demand and commodity, and shall be added to or deducted from, as appropriate, the respective demand and commodity costs included in the Gas Charge Adjustment. Supplemental sheets showing the calculations of margin losses and cost savings shall also be provided.

D. **Adjustments to Prior Period ACAs.**

In the event that circumstances warrant a correction to or restatement of a prior period ACA, such correction or restatement shall be made in accordance with the ACA calculation in effect for the time period(s) to which the correction or restatement relates. The resulting adjustment shall then be added to or deducted from the appropriate ACA in the next ensuing ACA filing with the Authority.

E. **Annual Filing with the Authority.**
Each year, the Company shall file with the Authority an annual report reflecting the transactions in the Deferred Gas Cost Account. Unless the Authority provides written notification to the Company within 180 days, the Deferred Gas Cost Adjustment Account shall be deemed in compliance with the provisions of this Rider.

IV. GAS COST ACCOUNTING

To appropriately match revenues with cost of purchased gas as contemplated under this rule, the Company shall originally record the cost of purchased gas in a "Deferred Gas Cost" account. Monthly the Company shall debit "Natural Gas Purchases" with an amount equal to any gas cost component included in the Company's base tariff rates (base rate) plus the PGA rate, as calculated hereunder, multiplied by the appropriate sales volumes billed to customers. The corresponding monthly credit entry shall be made to the "Deferred Gas Cost" account.

Discovery Request No. 20

Identify and produce all materials provided to, reviewed by or produced by any expert or consultant retained by Petitioners' to testify or provide information from which another expert will testify concerning this case.

Response:

See response to Discovery Request No. 18.

Chattanooga Gas Company
Docket 03-00209
Consumer Advocate and Protection Division of the Office of The Attorney General
Discovery Request Issued July 28, 2003

Discovery Request No. 21

Identify and produce all work papers of Petitioners' proposed experts, including but not limited to file notes, chart notes, tests, test results, interviews and/or consult notes and all other file documents that any of Petitioners' expert witnesses in any way used, created, generated or consulted by any Petitioners' expert witnesses in connection with the evaluation conclusion and opinion in this matter.

Response:

Chattanooga Gas Company objects to this request on the basis that it is overly broad and unduly burdensome. Subject to and without waiving the foregoing objection to this request, the Company will produce Mr. Hickerson's workpapers.

Chattanooga Gas Company
Docket 03-00209
Consumer Advocate and Protection Division of the Office of The Attorney General
Discovery Request Issued July 28, 2003

<u>Discovery Request No. 22:</u>

Identify and produce a copy of all trade articles, journals, treatises and publications of any kind in any way utilized or relied upon by any of Petitioners' proposed expert witnesses in evaluating, reaching conclusion or formulating an opinion in this matter.

Response:

No testimony has yet been prepared. The primary publications relied on by Mr. Hickerson are the Tennessee Regulatory Authority Administrative Rule 1220-4-7 and Chattanooga Gas Company TRA Gas Tariff No. 1 Pages 50-50F.

Discovery Request No. 23

Identify and produce a copy of all documents which relate or pertain to any factual information provided to, gathered by, utilized or relied upon by any of Petitioners' proposed expert witnesses in evaluating, reaching conclusions or formulating an opinion in this matter.

Response:

No testimony has yet been prepared.

Discovery Request No. 24

Identify and produce a copy of all articles, journals, books or speeches written by or co-written by any of Petitioners' expert witnesses, whether published or not.

Responses:

Mr. Hickerson has not maintained copies of speeches or presentations that he has prepared or co-prepared while employed by the Tennessee Public Service Commission from 1976-1994, with the Office of the Attorney General and Reporter State of Tennessee –Consumer Advocate Division 1994-2000, or with AGL Services Company 2000-present.

Discovery Request No. 20

Identify and produce all materials provided to, reviewed by or produced by any expert or consultant retained by Petitioners' to testify or provide information from which another expert will testify concerning this case.

Response:

See response to Discovery Request No. 18.

Discovery Request No. 21

Identify and produce all work papers of Petitioners' proposed experts, including but not limited to file notes, chart notes, tests, test results, interviews and/or consult notes and all other file documents that any of Petitioners' expert witnesses in any way used, created, generated or consulted by any Petitioners' expert witnesses in connection with the evaluation conclusion and opinion in this matter.

Response:

Chattanooga Gas Company objects to this request on the basis that it is overly broad and unduly burdensome. Subject to and without waiving the foregoing objection to this request, the Company will produce Mr. Hickerson's workpapers.

Discovery Request No. 22:

Identify and produce a copy of all trade articles, journals, treatises and publications of any kind in any way utilized or relied upon by any of Petitioners' proposed expert witnesses in evaluating, reaching conclusion or formulating an opinion in this matter.

Response:

No testimony has yet been prepared. The primary publications relied on by Mr. Hickerson are the Tennessee Regulatory Authority Administrative Rule 1220-4-7 and Chattanooga Gas Company TRA Gas Tariff No. 1 Pages 50-50F.

Discovery Request No. 23

Identify and produce a copy of all documents which relate or pertain to any factual information provided to, gathered by, utilized or relied upon by any of Petitioners' proposed expert witnesses in evaluating, reaching conclusions or formulating an opinion in this matter.

Response:

No testimony has yet been prepared.

<u>Discovery Request No. 24</u>

Identify and produce a copy of all articles, journals, books or speeches written by or co-written by any of Petitioners' expert witnesses, whether published or not.

Responses:

Mr. Hickerson has not maintained copies of speeches or presentations that he has prepared or co-prepared while employed by the Tennessee Public Service Commission from 1976-1994, with the Office of the Attorney General and Reporter State of Tennessee –Consumer Advocate Division 1994-2000, or with AGL Services Company 2000-present.

Discovery Request No. 20

Identify and produce all materials provided to, reviewed by or produced by any expert or consultant retained by Petitioners' to testify or provide information from which another expert will testify concerning this case.

Response:

See response to Discovery Request No. 18.

Chattanooga Gas Company
Docket 03-00209
Consumer Advocate and Protection Division of the Office of The Attorney General
Discovery Request Issued July 28, 2003

<u>Discovery Request No. 21</u>

Identify and produce all work papers of Petitioners' proposed experts, including but not limited to file notes, chart notes, tests, test results, interviews and/or consult notes and all other file documents that any of Petitioners' expert witnesses in any way used, created, generated or consulted by any Petitioners' expert witnesses in connection with the evaluation conclusion and opinion in this matter.

Response:

Chattanooga Gas Company objects to this request on the basis that it is overly broad and unduly burdensome. Subject to and without waiving the foregoing objection to this request, the Company will produce Mr. Hickerson's workpapers.

Discovery Request No. 22:

Identify and produce a copy of all trade articles, journals, treatises and publications of any kind in any way utilized or relied upon by any of Petitioners' proposed expert witnesses in evaluating, reaching conclusion or formulating an opinion in this matter.

Response:

No testimony has yet been prepared. The primary publications relied on by Mr. Hickerson are the Tennessee Regulatory Authority Administrative Rule 1220-4-7 and Chattanooga Gas Company TRA Gas Tariff No. 1 Pages 50-50F.

Chattanooga Gas Company
Docket 03-00209
Consumer Advocate and Protection Division of the Office of The Attorney General
Discovery Request Issued July 28, 2003

Discovery Request No. 23

Identify and produce a copy of all documents which relate or pertain to any factual information provided to, gathered by, utilized or relied upon by any of Petitioners' proposed expert witnesses in evaluating, reaching conclusions or formulating an opinion in this matter.

Response:

No testimony has yet been prepared.

Chattanooga Gas Company
Docket 03-00209
Consumer Advocate and Protection Division of the Office of The Attorney General
Discovery Request Issued July 28, 2003

Discovery Request No. 24

Identify and produce a copy of all articles, journals, books or speeches written by or co-written by any of Petitioners' expert witnesses, whether published or not.

Responses:

Mr. Hickerson has not maintained copies of speeches or presentations that he has prepared or co-prepared while employed by the Tennessee Public Service Commission from 1976-1994, with the Office of the Attorney General and Reporter State of Tennessee –Consumer Advocate Division 1994-2000, or with AGL Services Company 2000-present.

Discovery Request No. 20

Identify and produce all materials provided to, reviewed by or produced by any expert or consultant retained by Petitioners' to testify or provide information from which another expert will testify concerning this case.

Response:

See response to Discovery Request No. 18.

Discovery Request No. 21

Identify and produce all work papers of Petitioners' proposed experts, including but not limited to file notes, chart notes, tests, test results, interviews and/or consult notes and all other file documents that any of Petitioners' expert witnesses in any way used, created, generated or consulted by any Petitioners' expert witnesses in connection with the evaluation conclusion and opinion in this matter.

Response:

Chattanooga Gas Company objects to this request on the basis that it is overly broad and unduly burdensome. Subject to and without waiving the foregoing objection to this request, the Company will produce Mr. Hickerson's workpapers.

Discovery Request No. 22:

Identify and produce a copy of all trade articles, journals, treatises and publications of any kind in any way utilized or relied upon by any of Petitioners' proposed expert witnesses in evaluating, reaching conclusion or formulating an opinion in this matter.

Response:

No testimony has yet been prepared. The primary publications relied on by Mr. Hickerson are the Tennessee Regulatory Authority Administrative Rule 1220-4-7 and Chattanooga Gas Company TRA Gas Tariff No. 1 Pages 50-50F.

Discovery Request No. 23

Identify and produce a copy of all documents which relate or pertain to any factual information provided to, gathered by, utilized or relied upon by any of Petitioners' proposed expert witnesses in evaluating, reaching conclusions or formulating an opinion in this matter.

Response:

No testimony has yet been prepared.

Discovery Request No. 24

Identify and produce a copy of all articles, journals, books or speeches written by or co-written by any of Petitioners' expert witnesses, whether published or not.

Responses:

Mr. Hickerson has not maintained copies of speeches or presentations that he has prepared or co-prepared while employed by the Tennessee Public Service Commission from 1976-1994, with the Office of the Attorney General and Reporter State of Tennessee –Consumer Advocate Division 1994-2000, or with AGL Services Company 2000-present.