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 September 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)

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 September 30, 2003
Common Stock, $5.00 Par Value	64,266,376

AGL RESOURCES INC.

Quarterly Report on Form 10-Q

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	Earnings Before Interest and Taxes, 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 consists primarily of SouthStar, US Propane (and its investment in Heritage) and AGL Networks
FASB	Financial Accounting Standards Board
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
RMC	Risk Management Committee
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 13	SFAS No. 13, “Accounting for Leases”
SFAS 66	SFAS No. 66, “Accounting for Sales of Real Estate”
SFAS 123	SFAS No. 123, “Accounting for Stock-Based Compensation”
SFAS 133	SFAS No. 133, “Accounting for Derivative Instruments and Hedging Activities”
SFAS 142	SFAS No. 142, “Goodwill and Other Intangible Assets”
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	September 30, 2003	December 31, 2002
Current assets		
Cash and cash equivalents	$1.0	$8.4
Receivables (less allowance for uncollectible accounts of $2.2 million at September 30, 2003 and $2.3 million at December 31, 2002)	224.2	373.1
Inventories	254.1	118.2
Unrecovered environmental response costs – current	23.9	21.8
Unrecovered pipeline replacement program costs – current	18.9	15.0
Energy marketing and risk management assets	10.2	24.7
Other current assets	18.9	25.2
Total current assets	551.2	586.4
Property, plant and equipment		
Property, plant and equipment	3,400.1	3,323.2
Less accumulated depreciation	1,165.8	1,129.0
Property, plant and equipment-net	2,234.3	2,194.2
Deferred debits and other assets		
Unrecovered pipeline replacement program costs	425.6	499.3
Goodwill	176.6	176.2
Unrecovered environmental response costs	163.4	173.3
Investments in equity interests	115.4	74.8
Unrecovered postretirement benefit costs	10.7	10.9
Other	19.3	26.9
Total deferred debits and other assets	911.0	961.4
Total assets	$3,696.5	$3,742.0

See Notes to Condensed Consolidated Financial Statements (Unaudited).

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

In millions	September 30, 2003	December 31, 2002
Current liabilities		
Payables	$298.5	$341.8
Short-term debt	127.2	388.6
Accrued pipeline replacement program costs – current	74.2	50.0
Accrued expenses	55.6	58.2
Accrued environmental response costs – current	54.3	41.3
Current portion of long-term debt	42.0	30.0
Energy marketing and risk management liabilities	7.7	17.9
Other current liabilities	56.5	88.0
Total current liabilities	716.0	1,015.8
Accumulated deferred income taxes	360.3	320.0
Long-term liabilities		
Accrued pipeline replacement program costs	344.6	444.0
Accrued pension obligations	61.8	72.7
Accrued postretirement benefit costs	51.4	49.2
Accrued environmental response costs	40.3	63.7
Other	10.2	-
Total long-term liabilities	508.3	629.6
Deferred credits	73.2	72.3
Commitments and contingencies (Note 8)		
Capitalization		
Senior and Medium-Term notes	903.5	767.0
Trust Preferred Securities	226.7	227.2
Total long-term debt	1,130.2	994.2
Common shareholders' equity, $5 par value	908.5	710.1
Total capitalization	2,038.7	1,704.3
Total liabilities and capitalization	$3,696.5	$3,742.0

See Notes to Condensed Consolidated Financial Statements (Unaudited).

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
In millions, except per share amounts	2003	2002	2003	2002
Operating revenues	$166.3	$193.0	$705.4	$626.1
Cost of sales	29.2	57.0	223.2	178.5
Operating margin	137.1	136.0	482.2	447.6
Operating expenses				
Operation and maintenance	65.6	69.1	207.7	204.5
Depreciation and amortization	23.6	21.4	68.6	67.0
Taxes other than income	5.6	7.1	21.2	21.8
Total operating expenses	94.8	97.6	297.5	293.3
Gain on sale of Caroline Street campus	15.9	-	15.9	-
Operating income	58.2	38.4	200.6	154.3
Other income (loss)	5.5	(2.4)	29.9	22.2
Donation to private foundation	(8.0)	-	(8.0)	-
Interest expense and dividends on preferred securities	(19.2)	(21.4)	(57.3)	(65.3)
Earnings before income taxes	36.5	14.6	165.2	111.2
Income taxes	14.3	5.2	64.5	39.4
Income before cumulative effect of change in accounting principle	22.2	9.4	100.7	71.8
Cumulative effect of change in accounting principle, net of $4.8 million in taxes	-	-	(7.8)	-
Net income	$22.2	$9.4	$92.9	$71.8
Basic earnings per common share:				
Income before cumulative effect of change in accounting principle	$0.35	$0.17	$1.61	$1.28
Cumulative effect of change in accounting principle	-	-	(0.13)	-
Basic	$0.35	$0.17	$1.48	$1.28
Diluted earnings per common share:				
Income before cumulative effect of change in accounting principle	$0.34	$0.17	$1.59	$1.27
Cumulative effect of change in accounting principle	-	-	(0.12)	-
Diluted	$0.34	$0.17	$1.47	$1.27
Weighted-average number of common shares outstanding:				
Basic	64.0	56.2	62.6	56.0
Diluted	64.8	56.6	63.2	56.4

See Notes to Condensed Consolidated Financial Statements (Unaudited).

AGL RESOURCES INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY
FOR THE NINE MONTHS ENDED SEPTEMBER 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	-	-	92.9	-	-	92.9
Unrealized loss from equity investments hedging activities (net of tax benefit of $0.9 million)	-	-	-	(1.4)		(1.4)
Total comprehensive income (See Note 1)						91.5
Dividends on common shares ($0.83 per share)	-	-	(52.8)	-	-	(52.8)
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	0.1	3.9	-	-	19.0	23.0
Total issuance of common shares						159.7
Balance as of September 30, 2003	$321.3	$318.2	$319.9	($50.6)	($0.3)	$908.5

See Notes to Condensed Consolidated Financial Statements (Unaudited).

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

	Nine Months Ended September 30,	
In millions	2003	2002
Cash flows from operating activities		
Net income	$92.9	$71.8
Adjustments to reconcile net income to net cash flow from operating activities:		
Depreciation and amortization	68.6	67.0
Deferred income taxes	40.3	60.0
Cumulative effect of accounting change, net of taxes	7.8	-
Gain on sale of Caroline Street campus	(15.9)	-
Undistributed earnings of equity investments	(22.6)	(22.0)
Change in risk management assets and liabilities	(3.5)	(0.2)
Changes in certain assets and liabilities:		
Receivables	148.9	(28.3)
Payables	(43.3)	60.9
Inventories	(135.9)	49.5
Other	(36.2)	(26.0)
Net cash flow provided by operating activities	101.1	232.7
Cash flows from investing activities		
Property, plant and equipment expenditures	(112.6)	(121.3)
Investment in equity interests	(20.0)	-
Cash received from sale of Caroline Street campus	22.7	-
Cash received from equity investments	-	26.3
Other	2.0	(1.7)
Net cash flow used in investing activities	(107.9)	(96.7)
Cash flows from financing activities		
Payments and borrowings of short-term debt, net	(261.4)	(64.6)
Payments of Medium-Term notes	(72.5)	(45.0)
Dividends paid on common shares	(52.8)	(45.4)
Borrowing of Senior Notes	225.0	-
Equity offering	136.7	-
Sale of treasury shares	18.9	12.8
Other	5.5	5.0
Net cash flow used in financing activities	(0.6)	(137.2)
Net decrease in cash and cash equivalents	(7.4)	(1.2)
Cash and cash equivalents at beginning of period	8.4	7.3
Cash and cash equivalents at end of period	$1.0	$6.1
Cash paid during the period for:		
Interest	$42.6	$52.1
Income taxes	$9.0	$15.3

See Notes to Condensed Consolidated Financial Statements (Unaudited).

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

1. Significant Accounting Policies

General

AGL Resources Inc. is an energy services holding company, and conducts substantially all of its operations through its subsidiaries. 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 condensed 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 nine months ended September 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 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. The year-end balance sheet amounts are derived from the audited financial statements.

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 September 30, 2003, we included accumulated removal costs of $105.4 million in our total accumulated depreciation.

Goodwill and Other Intangible Assets

During July 2001, the FASB issued Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets," (SFAS 142) and we adopted SFAS 142 effective October 1, 2001. Under SFAS 142, goodwill amortization ceased when the new standard was adopted, and this resulted in us ceasing the annual amortization of goodwill in the amount of $5.2 million before tax. SFAS 142 further required an initial goodwill impairment assessment in the year of adoption and annual impairment tests thereafter. Our initial assessment for goodwill impairment on adoption of SFAS 142 was performed principally in relation to Virginia Natural Gas (VNG), but consideration was also given to the distribution operations segment as a whole since VNG has similar economic characteristics to Atlanta Gas Light Company (AGLC) and Chattanooga Gas Company (CGC).

Our initial assessment took into consideration both the purchase price of VNG as of October 6, 2000 as a means to establish the fair value of VNG, and VNG's annual filing with the Virginia State Corporation Commission, which provides VNG's actual rate of return as compared to its authorized rate of return. Also, we considered similar periodic regulatory filings by AGLC and CGC in our assessment of goodwill impairment for the distribution operations segment as a whole. No impairment charges were recognized as a result of our initial impairment assessment. Subsequent to our adoption of SFAS 142, we annually assess goodwill for impairment purposes as of our fiscal year end, or December 31, and have not recognized any impairment charges for the three months ended December 31, 2001 and the twelve months ended December 31, 2002. For these subsequent impairment assessments, and since the initial fair value assessment exceeded the amount of goodwill, we have carried forward the initial fair value assessment because:

- the assets and liabilities of VNG and the distribution operations segment as a whole have not changed significantly; and
- the likelihood is remote that the current fair value of VNG and the distribution operations segment as a whole would be less than the amount of goodwill given that circumstances have not appreciably changed since the last fair value assessment.

We assess changes in events and circumstances principally through review of financial results, changes in state and federal legislation and regulation, and the periodic regulatory filings for VNG, AGLC and CGC.

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. For our stock appreciation rights, we reflect stock-based employee compensation cost based upon fair value of our common stock at the balance sheet date since these awards constitute a variable plan under APB 25.

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 in accounting methods for stock based employee compensation 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 applied the fair value recognition provisions of SFAS 123:

	Three Months Ended September 30,		Nine Months Ended September 30,	
In millions, except per share amounts	2003	2002	2003	2002
Net income, as reported	$22.2	$9.4	$92.9	$71.8
Deduct: Total stock-based employee compensation expense determined under fair value-based method for all awards, net of related tax effect	1.9	0.2	2.2	1.9
Pro forma net income	$20.3	$9.2	$90.7	$69.9
Earnings per share:				
Basic-as reported	$0.35	$0.17	$1.48	$1.28
Basic-pro forma	$0.32	$0.16	$1.45	$1.25
Diluted-as reported	$0.34	$0.17	$1.47	$1.27
Diluted-pro forma	$0.31	$0.16	$1.44	$1.24

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.

SouthStar Energy Services, L.L.C. (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. For derivative transactions that are designated and qualify as cash flow hedges, SouthStar records the fair value of the open positions in its balance sheet with the unrealized gain or loss in other comprehensive income. For the three and nine months ended September 30, 2003, we recorded an after-tax charge to other comprehensive income of $1.4 million (net of income tax benefit of $0.9 million) for our 70% ownership interest in SouthStar's unrealized loss associated with its cash flow hedges. The following table shows our comprehensive loss for the three and nine months ended September 30, 2003 and 2002:

	Three Months Ended September 30,		Nine Months Ended September 30,	
In millions	2003	2002	2003	2002
Net income	$22.2	$9.4	$92.9	$71.8
Unrealized loss from equity investments hedging activities (net of tax benefit of $0.9 million)	(1.4)	-	(1.4)	-
Comprehensive income	$20.8	$9.4	$91.5	$71.8

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 reduction in earnings per common share that could occur when potential dilutive common shares are added to common shares outstanding.

We derive our potential dilutive common shares by calculating the number of shares issuable under performance units and stock options. The future issuance of shares underlying the performance units depends on the satisfaction of certain performance criteria. The future issuance of shares underlying the outstanding stock options depends upon whether the exercise prices of the stock options are less than the average market price of the common shares for the respective periods. There are no items that are anti-dilutive. The following table shows our calculation of our diluted earnings per share for the three months ended September 30, 2003 if performance units currently earned under the plan ultimately vest, and stock options currently exercisable at prices below the three month and nine month average market prices of $27.80 and $25.50, respectively, are exercised:

	Three Months Ended September 30,		Nine Months Ended September 30,	
In millions	2003	2002	2003	2002
Denominator for basic earnings per share (daily weighted-average shares outstanding)	64.0	56.2	62.6	56.0
Assumed exercise of performance units and stock options	0.8	0.4	0.6	0.4
Denominator for diluted earnings per share	64.8	56.6	63.2	56.4

Equity Investments

We use the equity method to account for any investment in an entity in which we have a 20% to 50% voting interest, unless we can exercise control 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 of the entity's earnings or losses is reported in our condensed statements of consolidated income under other income.

2. Recent Accounting Pronouncements

In January 2003, the FASB issued FASB Interpretation No. 46, "Consolidation of Variable Interest Entities," (FIN 46) which requires the primary beneficiary of a variable interest entity's activities to consolidate the variable interest entity. The primary beneficiary is the party that absorbs a majority of the expected losses and/or receives a majority of the expected residual returns of the variable interest entity's activities. FIN 46 is immediately applicable to variable interest entities created, or interests in variable interest entities obtained, after January 31, 2003. For variable interest entities created, or interests in variable interest entities obtained, on or before January 31, 2003, FIN 46 is now required to be applied in the first fiscal year or interim period beginning after September 15, 2003, a three month delay from the original effective date of the first annual or interim period beginning after June 15, 2003. FIN 46 may be applied prospectively with a cumulative-effect adjustment as of the date it is first applied, or by restating previously issued financial statements with a cumulative-effect adjustment as of the beginning of the first year restated. FIN 46 also requires certain disclosures of an entity's relationship with variable interest entities.

In addition, a company with unconsolidated entities subject to FIN 46 (referred to as variable interest entities) that issues financial statements on or after January 31, 2003 is 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 entities. FIN 46 separates unconsolidated entities, including special purpose entities and equity investments, 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 SouthStar and US Propane, L.L.C. (US Propane) since these entities do not meet the definition of a variable interest entity as defined in FIN 46.

In April 2003, the FASB issued SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities," (SFAS 149) which amends and clarifies financial accounting and reporting for derivative instruments and for hedging activities, including the qualifications for the normal purchases and normal sales exception, under SFAS 133. The amendment reflects decisions made by FASB in connection with issues raised about the application of SFAS 133. Generally, the provisions of SFAS 149 will be applied prospectively for contracts entered into or modified after June 30, 2003, and for hedging relationships designated after June 30, 2003. Our adoption of SFAS 149 did not have a material effect on our condensed consolidated results of operations, cash flows or financial position.

In May 2003, the FASB issued SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity," (SFAS 150) which establishes standards for classification and measurement of certain financial instruments with characteristics of both liabilities and equities. Under SFAS 150, such financial instruments are required to be classified as liabilities in the statement of financial position. The financial instruments affected include mandatorily redeemable stock, certain financial instruments that require or may require the issuer to buy back some of its shares in exchange for cash or other assets, and certain obligations that can be settled with shares of stock. SFAS 150 is effective for all financial instruments entered into or modified after May 31, 2003 and was applied to our existing financial instruments beginning on July 1, 2003. Our adoption of SFAS 150 did not have a material effect on our condensed consolidated results of operations, cash flows or financial position.

3. Common Shareholders' Equity

On February 14, 2003, we announced the completion of our public offering of 6.4 million shares of common stock. 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.

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

Shares in millions	Authorized	Issued	Treasury Shares	Outstanding
As of December 31, 2002	750.0	57.8	(1.1)	56.7
Common share activity	-	6.6	1.0	7.6
As of September 30, 2003	750.0	64.4	(0.1)	64.3

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

	Nine Months Ended September 30,	
All amounts on a per share basis	2003	2002
Equity offering	$22.00	$ -
Issuance of treasury shares	22.78	20.49
Weighted average issuance price of common shares	$22.12	$20.49

Our common shareholders may receive common stock dividends when declared by our Board of Directors. Common stock dividends may be paid in cash, stock or other form of payment. In certain cases, common shareholders may not receive common stock dividends until we have satisfied our obligations under certain financing agreements and satisfied our obligations to any preferred shareholders. Our ability to pay common stock dividends is limited by Georgia law and the Public Utility Holding Company Act of 1935, as amended (PUHCA).

Under Georgia law, common stock dividends are limited to our legally available assets and subject to the prior payment of common stock dividends on any outstanding shares of preferred stock and junior preferred stock. Under Georgia law, assets are not legally available for paying dividends if (1) we would not be able to pay our debts as they become due in the usual course of business or (2) our total assets would be less than our total liabilities plus, subject to some exceptions, any amounts necessary to satisfy the preferential rights upon dissolution of shareholders whose preferential rights are superior to those of common shareholders receiving the common stock dividends. PUHCA restricts our payment of dividends out of capital or unearned surplus without prior permission from the Securities and Exchange Commission.

On April 16, 2003, we announced a 3.7% 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.

4. Other Income

Our other income consists of the following:

In millions	Three Months Ended September 30, 2003	Three Months Ended September 30, 2002	Nine Months Ended September 30, 2003	Nine Months Ended September 30, 2002
Equity in earnings of SouthStar (1)	$5.7	($2.2)	$29.2	$22.5
Equity in earnings of US Propane	(0.1)	(0.4)	0.9	(0.5)
Allowance for funds used during construction	0.4	0.6	1.1	1.8
All other – net	(0.5)	(0.4)	(1.3)	(1.6)
Total other income	$5.5	($2.4)	$29.9	$22.2

(1) See Note 10 for a discussion of SouthStar's disproportionate sharing of earnings.

5. Risk Management

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. Two areas where SFAS 133 is applicable for us are interest rate swaps and gas commodity contracts at Sequent Energy Management, LP (Sequent).

Interest Rate Swaps To maintain an 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 September 30, 2003, a notional principal amount of $275.0 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 September 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%. The effective rate for the three months and nine months ended September 30, 2003 was 4.6%. These interest rate swaps expire January 14, 2011, unless terminated earlier.
- $100.0 million principal amount of our 4.45% Senior Notes due 2013 - we pay floating interest each April 15 and October 15 at six-month LIBOR plus 0.615%. For the three months ended September 30, 2003, the effective variable interest rate was 1.7%. These interest rate swaps expire April 15, 2013, 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 September 30, 2003 was 2.5% and for the nine months ended September 30, 2003 was 2.6%. These interest rate swaps expire May 15, 2041, unless terminated earlier.

We designated these interest rate swaps as fair value hedges as defined by SFAS 133, which allows us to designate derivatives that hedge exposure to changes in the fair value of a recognized asset or liability. We record 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 this 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, which represent liabilities, at September 30, 2003, was $0.8 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.

We attempt to mitigate substantially all of the 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 Emerging Issues Task Force (EITF) Issue No. 02-03, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities" (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 lower of cost or market 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 the realization of the economic profit margin we originally expected to attain. 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 (RMC). The RMC is the committee of senior officers that is charged with the review and enforcement of our risk management policy. We use the following derivative financial instruments and physical transactions to manage commodity price risks:

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

Our risk management policy limits the use of derivative financial instruments and physical transactions within predefined risk tolerances 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 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 02-03, which 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.

As a result of our adoption of EITF 02-03, we:

- 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. This reclassification had no impact on our previously reported net income or shareholders' equity.

Our commodity related derivative financial instruments, which exclude our interest rate swaps discussed earlier, have a weighted average maturity of approximately 4 months based on volumes. Our commodity related derivative financial instruments, at September 30, 2003, represented purchases (long) of 289.9 billion cubic feet and sales (short) of 309.1 billion cubic feet.

We recorded unrealized gains of $2.2 million for the three months ended September 30, 2003 and $1.2 million for the three months ended September 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 nine months ended September 30, 2003 were $8.3 million and were $0.2 million for the nine months ended September 30, 2002.

The following table includes the fair values and average values of Sequent's energy marketing and risk management assets and liabilities at September 30, 2003 and December 31, 2002. We based the average values on a monthly average for the three months and the nine months ended September 30, 2003.

	Asset			
	Average Values		Value at:	
In millions	Three Months	Nine Months	Sept. 30, 2003	Dec. 31, 2002
Natural gas contracts	$12.5	$14.3	$10.2	$24.7

	Liability			
	Average Values		Value at:	
In millions	Three Months	Nine Months	Sept. 30, 2003	Dec. 31, 2002
Natural gas contracts	$10.7	$15.4	$7.7	$17.9

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) and poolers in Georgia. Marketers are responsible for the retail sale of natural gas to end-use customers in Georgia. The retail function includes customer service, billing, collections, and the purchase and sale of the natural gas commodity. For the nine months ended September 30, 2003, the four largest Marketers based on customer count (one of which is our partially owned affiliate, SouthStar) accounted for approximately 58% of the Company’s and 64% 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. The RMC 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 and utility and industrial customers, also has a concentration of credit risk which is measured by 30 day receivable exposure plus forward exposure. Sequent’s top 20 counterparties represent approximately 76% of the total counterparty exposure of $115 million, derived by adding the top 20 counterparties’ exposures and dividing by the total counterparties’ exposures.

As of September 30, 2003, Sequent’s counterparties, or the counterparties’ guarantors, had a weighted average Standard & Poor’s (S&P) equivalent credit rating of BBB compared to BBB+ at December 31, 2002. The S&P equivalent credit rating is determined by a process of converting the lower of the S&P or Moody’s ratings to an internal rating ranging from 9 to 1, with 9 being equivalent to AAA/Aaa by S&P and Moody’s and 1 being D or Default by S&P and Moody’s. A counterparty that does not have an external rating will be assigned an internal rating based on the strength of the financial ratios of the counterparty. The assigned internal rating is multiplied by the counterparty’s credit exposure and summed, then divided by the total aggregate counterparties’ exposures. This numeric value is converted to an S&P equivalent.

6. Regulatory Assets and Liabilities

We have recorded regulatory assets and liabilities in our condensed consolidated balance sheets in accordance with SFAS No. 71, “Accounting for the Effects of Certain Types of Regulation.” 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:

	As of	
In millions	September 30, 2003	December 31, 2002
Regulatory assets:		
Unrecovered pipeline replacement program costs	$444.5	$514.3
Unrecovered environmental response costs	187.3	195.1
Unrecovered postretirement benefit costs	10.7	10.9
Unrecovered seasonal rates	9.7	9.3
Unamortized call premium	2.7	-
Regulatory tax asset	2.3	3.4
Deferred purchased gas adjustment	0.5	7.6
Other	-	1.6
Total	$657.7	$742.2
Regulatory liabilities:		
Unamortized investment tax credit	$19.2	$20.2
Regulatory tax liability	15.1	15.8
Deferred purchased gas adjustment	13.4	18.0
Other	1.2	1.0
Total regulatory liabilities	48.9	55.0
Associated liabilities:		
Pipeline replacement program costs	418.8	494.0
Environmental response costs	94.6	105.0
Total associated liabilities	513.4	599.0
Total regulatory and associated liabilities	$562.3	$654.0

Our regulatory assets are recoverable through either rate riders or base rates specifically authorized by a state regulatory commission. Base rates are designed to provide both a recovery of cost and a return on investment during the period rates are in effect. As such, all of our regulatory assets are subject to review by the respective state regulatory commission during any future rate proceedings. It is our opinion that all regulatory assets are recoverable in future rate proceedings. We have not recorded any regulatory assets that are recoverable but are not yet included in base rates or contemplated in a rate rider.

All the regulatory assets included in the table above, are included in base rates except for the unrecovered pipeline replacement program costs, unrecovered environmental response costs and the deferred purchased gas adjustment, which are recovered through specific rate riders. The rate riders that authorize recovery of the unrecovered pipeline replacement program costs and the deferred purchased gas adjustment include both a recovery of costs and a return on investment during the recovery period. The rate rider that authorizes the recovery of the unrecovered environmental response costs only allows for recovery of the costs incurred. The recovery period for environmental response costs is five years after the expense is incurred.

The regulatory liabilities are refunded to ratepayers through a rate rider or base rates. If the regulatory liability is included in base rates, the amount is reflected as a reduction to rate base in setting rates.

Pipeline Replacement Program Costs

AGLC recorded a long-term liability of $344.6 million as of September 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. These estimates are reported on an undiscounted basis. The pipeline replacement program ordered by the GPSC to be administered by AGLC requires, among other things, that AGLC replace all bare steel and cast iron pipe in AGLC's system in the state of Georgia within a 10-year period, beginning October 1, 1998. AGLC identified and provided to the GPSC in accordance with this order 2,312 miles of bare steel and cast iron pipe to be replaced. If AGLC does not perform in accordance with this order, AGLC will be assessed certain non-performance penalties. The order also provides for recovery of all prudent costs incurred in the performance of the program, which AGLC has recorded as a regulatory asset. The regulatory asset has two components:

- the costs incurred to date that have not yet been recovered through this rate rider; and
- the future expected costs to be recovered through this rate rider.

As of September 30, 2003, AGLC had recorded a current liability of $74.2 million, representing expected pipeline replacement program expenditures for the next 12 months.

Environmental Response Costs

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 will be required at most of these sites.

AGLC has active environmental remediation or monitoring programs in effect at 10 sites. Two of the three sites in Florida and one Georgia site are currently in the preliminary investigation or engineering design phase. Where soil remediation is required at our Georgia sites, the work is targeted to be complete by January 2005. As of September 30, 2003, our MGP remediation program was approximately 68% complete.

AGLC has historically reported estimates of future remediation costs for MGPs based on probabilistic models of potential costs. These estimates are reported on an undiscounted basis. 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 June 30, 2003. This estimate projected costs associated with AGLC's engineering estimates and in-place contracts to be $72.8 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 $15.2 million to $27.5 million. AGLC cannot estimate any single number within this range as a better estimate of its likely future costs. As a result, we recorded the lower end of the range, or $15.2 million, for these remaining elements in its environmental response costs. AGLC estimates certain other costs related to administering the MGP program and the remediation of sites currently in investigation phase. Through January 2005, AGLC estimates the administrative costs to be $2.7 million.

Finally, there remains considerable variability in the estimates of costs related to the administering of the MGP program and the remediation of sites currently in investigation phase after January 2005. For these elements, the estimate ranges from $9.0 million to $14.6 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 $9.0 million for these remaining elements.

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

	As of:		
In millions	September 30, 2003	December 31, 2002	Change
Projected engineering estimates and in-place contracts	$72.8	$109.2	($36.4)
Estimated future remediation costs	15.2	9.3	5.9
Administrative expenses	2.7	1.3	1.4
Other expenses	9.0	-	9.0
Cash payments for cleanup expenditures	(5.1)	(14.8)	9.7
Accrued environmental response costs	$94.6	$105.0	($10.4)

The environmental response cost liability is included in a corresponding regulatory asset. As of September 30, 2003, the regulatory asset was $187.2 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 three 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 assets. During the three and nine months ended September 30, 2003, AGLC recovered $5.5 million and $16.6 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 nine months ended September 30, 2003. The third way AGLC can recover costs is from the receipt of net profits from sale of remediated property. There were no sales of remediated property during the nine months ended September 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 are incurred. As of September 30, 2003, the MGP expenditures expected to be incurred over the next twelve months are reflected as a current liability of $54.3 million. In addition, AGLC expects to collect $23.9 million in revenues over the next twelve months under the environmental response cost recovery rider, which is reflected as a current asset.

7. Financing

Dollars in millions	Year(s) Due	September 30, 2003 Interest rate	September 30, 2003 Outstanding	December 31, 2002 Interest rate	December 31, 2002 Outstanding
Short-term debt:					
Commercial paper (1)	2003	1.2%	$121.0	1.8%	$388.6
Current portion of long-term debt	2003	5.9 -6.85	42.0	5.9	30.0
Sequent line of credit (2)	2004	1.67	6.2	-	-
Total short-term debt (3)		**2.4%**	**$169.2**	**2.0%**	**$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	6.55 – 7.3	258.0	6.55 – 7.3	270.0
Senior Notes	2011-2013	4.45 - 7.125	525.0	7.125	300.0
AGL Capital Interest Rate Swaps	2011-2013	1.72 – 4.52	(4.0)	-	-
Total Medium-Term and Senior Notes			$903.5		$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	147.6	8.0	146.8
AGL Capital Interest Rate Swaps	2041	2.45	4.8	2.7	6.1
Total Trust Preferred Securities			$226.7		$227.2
Total long-term debt (3)		**6.1%**	**$1,130.2**	**6.9%**	**$994.2**
Total short-term and long-term debt (3)		**5.6%**	**$1,299.4**	**5.5%**	**$1,412.8**

(1) The daily weighted average rate was 1.5% for the nine months ended September 30, 2003 and 2.2% for the twelve months ended December 31, 2002.

(2) The daily weighted average rate was 1.6% for the nine months ended September 30, 2003 and 2.3% for the twelve months ended December 31, 2002.

(3) Weighted average interest rate, including interest rate swaps.

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 at a call premium of $0.3 million. 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 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 of $2.4 million. We recorded this call premium as a regulatory asset and will amortize and collect in rates the call premium over the remaining life of the notes on the day they are retired, which is 10 to 20 years. 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 as well as approximately $110.0 million of short-term debt.

On July 2, 2003, the $15.0 million unsecured Sequent line of credit was renewed with an expiration date of July 2, 2004. This line is used solely for the posting of margin deposits for New York Mercantile Exchange transactions, is unconditionally guaranteed by AGL Resources, and bears interest at the federal funds effective rate plus 0.5%.

Additionally on July 2, 2003, 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 variable rate obligation resulting from the interest rate swap 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.

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%. 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 and covenants.

8. Commitments and Contingencies

The following table illustrates our expected future contractual cash obligations as of September 30, 2003:

		Payments Due before December 31,			
In millions	Total	2003	2004 & 2005	2006 & 2007	2008 & Thereafter
Long-term debt (1)	$1,172.2	$42.0	$75.5	$10.0	$1,044.7
Pipeline charges, storage capacity and gas supply (2) (4)	758.6	62.7	378.5	120.7	196.7
Pipeline replacement program costs (3)	418.8	13.8	162.0	162.0	81.0
Short-term debt	127.2	121.0	6.2	-	-
Environmental response costs (3)	94.6	15.5	54.7	6.1	18.3
Operating leases (5)	84.1	3.1	22.7	18.2	40.1
Communication/ network service and maintenance	24.2	2.4	17.9	3.9	-
Total	$2,679.7	$260.5	$717.5	$320.9	$1,380.8

(1) Includes $226.7 million of Trust Preferred Securities, which are callable in 2006 and 2007.

(2) Charges recoverable through a purchased gas adjustment mechanism or alternatively billed to Marketers.

(3) Charges recoverable through rate rider mechanisms.

(4) 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.

(5) We have certain operating leases with provisions for step rent or escalation payments, or certain lease concessions. We account for these leases by recognizing the future minimum lease payments on a straight-line basis over the respective minimum lease terms, in accordance with SFAS 13, “Accounting for Leases.” However, this accounting treatment does not affect the future annual operating lease cash obligations as shown herein.

In January 2003, the FASB released FASB Interpretation No. 45, "Guarantor's 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 September 30, 2003 and meet the disclosure criteria required by FIN 45:

		Commitments Due before December 31,			
In millions	Total	2003	2004 & 2005	2006 & 2007	2008 & Thereafter
Lines of credit (1)	$515.0	$215.0	$300.0	$-	$-
Guarantees (2) (3)	149.6	149.6	-	-	-
Standby letters of credit, performance/ surety bonds	3.1	3.1	-	-	-
Total other commercial commitments	$667.7	$367.7	$300.0	$-	$-

(1) Comprised of our Credit Facility ($500.0 million) and Sequent's unsecured line of credit ($15.0 million).

(2) $142.6 million of these guarantees support credit exposures in Sequent's energy marketing and risk management business. In the event that Sequent defaults on any commitments under these guarantees, these amounts would become payable by us as guarantor.

(3) We provide guarantees on behalf of our affiliate, 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 credit support obligation to AGLC under its tariff.

Caroline Street Campus

On September 24, 2003 we finalized the sale of 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. Net proceeds from the sale were $22.7 million, resulting in a pre-tax gain of $15.9 million. On September 29, 2003, we contributed $8.0 million of these proceeds to the AGL Resources Private Foundation, Inc., a non-profit foundation, which makes charitable contributions to qualified tax-exempt organizations.

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 or 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. The City of Augusta's allegations include fraud and deceit and damages to realty. The allegations arise from negotiations between the city and AGLC regarding the environmental cleanup obligations connected with AGLC's former MGP 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 of Augusta. For more information about the MGPs and our environmental cleanup obligations, please see Item 1, Financial Statements, Note 5 "Regulatory Assets and Liabilities – Environmental Matters."

9. Related Party Transactions

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

In millions	Three Months Ended September 30, 2003	2002	Nine Months Ended September 30, 2003	2002
Revenue	$38.6	$54.9	$149.1	$185.8
Accounts receivable	-	-	-	-

10. Equity Investments

We apply the equity method of accounting for our investments in SouthStar and US Propane. The summarized unaudited amounts below represent 100% of the results of SouthStar. These results are not comparable with our earnings or losses from SouthStar, which we report as other income (loss) in our condensed consolidated statements of income, as those amounts are reported based on our 70% ownership percentage. SouthStar's net income from continuing operations and net income are equal because as a partnership, SouthStar does not incur income tax expenses.

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

In millions	As of: September 30, 2003	December 31, 2002
Balance Sheet:		
Current assets	$168.3	$169.0
Noncurrent assets	1.1	0.9
Current liabilities	50.6	83.6
Noncurrent liabilities	-	-

	Three Months Ended September 30, 2003	2002	Nine Months Ended September 30, 2003	2002
Income Statement:				
Revenues	$105.3	$87.9	$521.9	$424.5
Gross margin	19.5	13.5	92.3	89.1
Operating income (loss)	7.9	(4.5)	47.5	33.0
Net income (loss)	8.0	(4.3)	47.8	33.6

SouthStar's operating policy contains a provision for the disproportionate sharing of earnings between our partner in SouthStar, Piedmont Natural Gas Company (Piedmont), and us when SouthStar's annual earnings before taxes exceed a certain annual threshold. The annual threshold is calculated each year based on a cumulative and annual 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 believe based upon our interpretation of SouthStar's operating policy 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 in the range of $2.3 million to $4.4 million, before taxes. This is based on our estimate that our actual earnings from SouthStar were approximately 55.7% to 60.7% of total earnings, rather than the 50% reflective of our equity ownership. We estimate our increased portion of equity earnings from SouthStar for the twelve months ended December 31, 2001 and 2000 to be up to an aggregate of $2.6 million before taxes. No disproportionate distributions have occurred to date because the partners have not reached an agreement on how the disproportionate sharing should be calculated.

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 we have an agreement with Piedmont. 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 will occur again in 2003. We remain in active discussions with Piedmont to reach a resolution on the disproportionate sharing provisions.

Our investment in US Propane did not have a material effect on our financial position, results of operations or cash flows for the three or nine months ended September 30, 2003 and 2002.

11. Segment Information

Our business is organized into three operating segments:

- Distribution operations consists of AGLC, VNG and CGC.
- Wholesale services consists primarily of Sequent.
- Energy investments consists primarily of SouthStar, AGL Networks, LLC (AGL Networks) and US Propane.

We treat our corporate segment as a nonoperating business segment, and it 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 nine months ended September 30, 2003 and 2002 from our condensed consolidated statements of income.

Management evaluates segment performance based on the 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 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 EBIT to operating income and net income are presented below for the three and nine months ended September 30, 2003 and 2002:

	Three Months Ended September 30,		Nine Months Ended September 30,	
In millions	2003	2002	2003	2002
Operating income	$58.2	$38.4	$200.6	$154.3
Other income (loss)	5.5	(2.4)	29.9	22.2
Donation to private foundation	(8.0)	-	(8.0)	-
EBIT	55.7	36.0	222.5	176.5
Interest expense and preferred stock dividends	19.2	21.4	57.3	65.3
Earnings before income taxes	36.5	14.6	165.2	111.2
Income taxes	14.3	5.2	64.5	39.4
Income before cumulative effect of change in accounting principle	22.2	9.4	100.7	71.8
Cumulative effect of change in accounting principle	-	-	(7.8)	-
Net income	$22.2	$9.4	$92.9	$71.8

	Three months ended September 30,									
	Distribution Operations		Wholesale Services		Energy Investments		Corporate (2)		Consolidated AGL Resources	
In millions	2003	2002	2003	2002	2003	2002	2003	2002	2003	2002
Operating revenues (1)	$159.5	$186.6	$5.6	$5.5	$1.2	$1.1	-	($0.2)	$166.3	$193.0
Depreciation and amortization	20.4	19.8	-	-	0.4	0.1	2.8	1.5	23.6	21.4
Gain (loss) on sale of Caroline Street campus (3)	21.5	-	-	-	-	-	(5.6)	-	15.9	-
Operating income	65.0	44.6	1.2	1.3	(1.7)	(0.8)	(6.3)	(6.7)	58.2	38.4
Interest income	-	0.1	-	-	0.1	0.1	-	-	0.1	0.2
Donation to private foundation	(8.0)	-	-	-	-	-	-	-	(8.0)	-
Earnings in equity interests	-	-	-	-	5.6	(2.5)	-	-	5.6	(2.5)
Other income (loss)	0.5	0.3	(0.3)	-	-	-	(0.4)	(0.4)	(0.2)	(0.1)
Total other income (loss)	(7.5)	0.4	(0.3)	-	5.7	(2.4)	(0.4)	(0.4)	(2.5)	(2.4)
EBIT	57.5	45.0	0.9	1.3	4.0	(3.2)	(6.7)	(7.1)	55.7	36.0
Capital expenditures	31.8	28.7	-	0.7	0.7	-	2.9	4.5	35.4	33.9

	Nine months ended September 30,									
	Distribution Operations		Wholesale Services		Energy Investments		Corporate (2)		Consolidated AGL Resources	
In millions	2003	2002	2003	2002	2003	2002	2003	2002	2003	2002
Operating revenues (1)	$661.8	$609.7	$38.2	$15.0	$5.3	$1.6	$0.1	($0.2)	$705.4	$626.1
Depreciation and amortization	60.7	61.8	-	-	0.6	0.1	7.3	5.1	68.6	67.0
Gain (loss) on sale of Caroline Street campus (3)	21.5	-	-	-	-	-	(5.6)	-	15.9	-
Operating income	189.4	163.2	22.2	4.8	(3.8)	(4.2)	(7.2)	(9.5)	200.6	154.3
Interest income	0.1	0.3	-	-	0.2	0.1	0.1	-	0.4	0.4
Donation to private foundation	(8.0)	-	-	-	-	-	-	-	(8.0)	-
Earnings in equity interests	-	-	-	-	30.1	22.0	-	-	30.1	22.0
Other income (loss)	0.9	0.5	(0.3)	-	0.1	0.2	(1.3)	(0.9)	(0.6)	(0.2)
Total other income (loss)	(7.0)	0.8	(0.3)	-	30.4	22.3	(1.2)	(0.9)	21.9	22.2
EBIT	182.4	164.0	21.9	4.8	26.6	18.1	(8.4)	(10.4)	222.5	176.5
Capital expenditures	88.0	92.4	0.9	2.2	2.0	11.8	21.7	14.9	112.6	121.3

(1) Intersegment revenues – As a result of our adoption of EITF 02-03, 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:

	Three months ended September 30,		Nine Months Ended September 30,	
In millions	2003	2002	2003	2002
Third-party gross revenues	$645.3	$399.3	$2,520.0	$1,036.0
Intersegment revenues	84.0	30.9	291.1	80.6
Total gross revenues	$729.3	$430.2	$2,811.1	$1,116.6

(2) Includes intercompany eliminations.

(3) The gain before income taxes of $15.9 million on the sale of our Caroline Street campus was recorded as operating income (loss) in two of our segments. A gain of $21.5 million on the sale of the land was recorded in our distribution operations segment, and a write-off of ($5.6) million on the buildings and their contents was recorded in our corporate segment.

	As of:									
	Distribution Operations		Wholesale Services		Energy Investments		Corporate (2)		Consolidated AGL Resources	
In millions	Sept. 30, 2003	Dec. 31, 2002	Sept. 30, 2003	Dec. 31, 2002	Sept. 30, 2003	Dec. 31, 2002	Sept. 30, 2003	Dec. 31, 2002	Sept. 30, 2003	Dec. 31, 2002
Identifiable assets (1)	$3,175.0	$3,149.8	$354.9	$364.3	$88.2	$107.2	($37.0)	$45.9	$3,581.1	$3,667.2
Investments in equity interests	-	-	-	-	115.4	74.8	-	-	115.4	74.8
Total assets	$3,175.0	$3,149.8	$354.9	$364.3	$203.6	$182.0	($37.0)	$45.9	$3,696.5	$3,742.0

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

12. Subsequent Events

On October 23, 2003, we exercised our option to call at par a $10.0 million Medium-Term note bearing interest at 6.0% before its October 23, 2006 scheduled maturity date. On October 27, 2003, we exercised our option to call at a premium a $2.0 million Medium-Term note bearing interest at 6.85% before its October 26, 2023 scheduled maturity date. We redeemed these notes using proceeds from the issuance of commercial paper.

In October 2003, Sequent purchased two separate asset management agreements with non affiliates in the Northeast for approximately $4.0 million. Under the terms of these agreements, one of which expires in 2006 and the other which expires in 2012, Sequent has been assigned certain natural gas transportation and storage contracts to support its obligation to supply all of the gas requirements of the customers, mainly at index prices. Additionally, Sequent will be paid a services fee. We do not believe these agreements will have a material impact on our results of operations or financial condition.

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

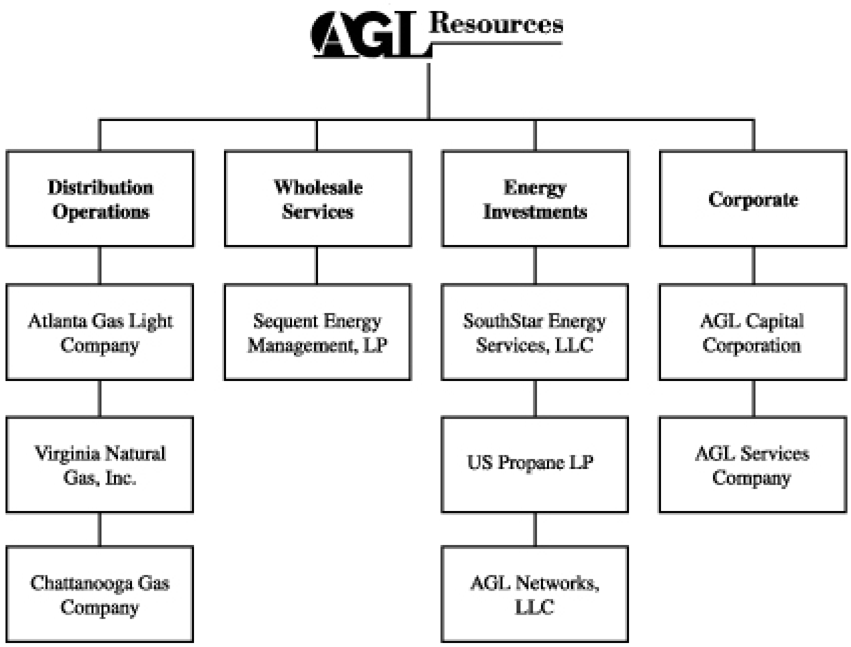
CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

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
- 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 the Georgia retail gas market, including risks related to energy marketing and risk management
- concentration of credit risk in Marketers and customers of our wholesale services segment
- 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 conduct substantially all of our operations through our subsidiaries. We operate three utilities, which combined, serve approximately 1.8 million end-use customers. We are also involved in various non-utility businesses, including natural gas asset management and producer services; leasing of telecommunications fiber within a few select metropolitan areas; retail gas marketing; and propane services. Our business strategy is to effectively manage our gas distribution operations, optimize returns on our assets, and selectively grow our portfolio of closely related, unregulated businesses with an emphasis on risk management and earnings visibility. The following chart shows our business segments and principal subsidiaries or affiliated companies, which we manage as three operating segments: distribution operations; wholesale services; and energy investments; and corporate, our one nonoperating segment:



Highlights

- For the three months ended September 30, 2003, our net income was $22.2 million or $0.34 per diluted common share. This was an increase of $12.8 million or $0.17 per diluted common share for the same period last year.
- For the nine months ended September 30, 2003, our net income was $92.9 million or $1.47 per diluted common share. This was an increase of $21.1 million or $0.20 per diluted common share for the same period last year. Our income before cumulative effect of change in accounting principle increased $28.9 million or $0.32 per diluted common share.
- In August 2003, we formed Pivotal Energy Development (PED) within AGL Services Company. PED will coordinate among our related companies our development, construction and/or acquisition of assets in the Southeast and mid-Atlantic regions that extend our natural gas capabilities and improve system reliability, while enhancing service to our customers in those areas. The initial focus of PED's commercial activities will be on improving the economics of system reliability and natural gas deliverability in these targeted regions.
- On September 24, 2003, we closed on the sale of our Caroline Street campus for net proceeds of $22.7 million, resulting in a gain before income taxes of $15.9 million. We contributed $8.0 million of these proceeds to the AGL Resources Private Foundation, Inc., a non-profit foundation, which makes charitable contributions to qualified tax-exempt organizations. After the contribution and net of taxes, the sale increased our basic earnings per common share by an additional $0.08 and our diluted earnings per common share by an additional $0.07 for the three months ended September 30, 2003 and $0.07 per basic and diluted share for the nine months ended September 30, 2003. The gain before income taxes of $15.9 million was recorded as operating income (loss) in two of our segments. A gain of $21.5 million on the sale of the land was recorded in our distribution operations segment, and a write-off of ($5.6) million on the buildings and their contents was recorded in our corporate segment.

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 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:

In millions, except per share amounts	**Three Months Ended September 30, 2003**	**2002**	**Change**	**Nine Months Ended September 30, 2003**	**2002**	**Change**
Operating income	$58.2	$38.4	$19.8	$200.6	$154.3	$46.3
Other income (loss)	5.5	(2.4)	7.9	29.9	22.2	7.7
Donation to private foundation	(8.0)	-	(8.0)	(8.0)	-	(8.0)
EBIT	55.7	36.0	19.7	222.5	176.5	46.0
Interest expense and dividends on preferred securities	(19.2)	(21.4)	2.2	(57.3)	(65.3)	8.0
Earnings before income taxes	36.5	14.6	21.9	165.2	111.2	54.0
Income taxes	(14.3)	(5.2)	(9.1)	(64.5)	(39.4)	(25.1)
Income before cumulative effect of change in accounting principle	22.2	9.4	12.8	100.7	71.8	28.9
Cumulative effect of change in accounting principle	-	-	-	(7.8)	-	(7.8)
Net income	22.2	9.4	12.8	92.9	71.8	21.1
Basic earnings per common share						
Income before cumulative effect of change in accounting principle	$0.35	$0.17	$0.18	$1.61	$1.28	0.33
Cumulative effect of change in accounting principle	-	-	-	(0.13)	-	(0.13)
Net income – basic	0.35	0.17	0.18	1.48	1.28	0.20
Diluted earnings per common share						
Income before cumulative effect of change in accounting principle	$0.34	$0.17	$0.17	$1.59	$1.27	$0.32
Cumulative effect of change in accounting principle	-	-	-	(0.12)	-	(0.12)
Net income – diluted	0.34	0.17	0.17	1.47	1.27	0.20
Weighted-average number of common shares outstanding						
Basic	64.0	56.2	7.8	62.6	56.0	6.6
Diluted	64.8	56.6	8.2	63.2	56.4	6.8

Results of Operations by Segment

Below are the results of operations by segment as measured by EBIT for the three and nine months ended September 30, 2003 and 2002:

	Three Months Ended September 30,			Nine Months Ended September 30,		
In millions	**2003**	**2002**	**Change**	**2003**	**2002**	**Change**
Distribution operations	$57.5	$45.0	$12.5	$182.4	$164.0	$18.4
Wholesale services	0.9	1.3	(0.4)	21.9	4.8	17.1
Energy investments	4.0	(3.2)	7.2	26.6	18.1	8.5
Corporate	(6.7)	(7.1)	0.4	(8.4)	(10.4)	2.0
Consolidated EBIT	$55.7	$36.0	$19.7	$222.5	$176.5	$46.0

Income Taxes

	Three Months Ended September 30,			Nine Months Ended September 30,		
Dollars in millions	**2003**	**2002**	**Change**	**2003**	**2002**	**Change**
Earnings before income taxes	$36.5	$14.6	$21.9	$165.2	$111.2	$54.0
Income tax expense	14.3	5.2	(9.1)	64.5	39.4	(25.1)
Effective tax rate	39.2%	35.6%	(3.6%)	39.0%	35.4%	(3.6%)

The increase in our income tax expense of $9.1 million for the three months ended September 30, 2003 as compared to the three months ended September 30, 2002 was due primarily to the increase in earnings before income taxes of $21.9 million and the increase in our effective tax rate from 35.6% in 2002 to 39.2% in 2003.

The increase in income tax expense of $25.1 million for the nine months ended September 30, 2003 as compared to the nine months ended September 30, 2002 was due primarily to the increase in earnings before income taxes of $54.0 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 for the three and nine months ended September 30, 2003 is primarily due to higher projected state income taxes resulting from a change in Georgia law governing the methodology by which Georgia companies compute their tax liabilities.

Interest Expense and Preferred Securities Dividends

	Three Months Ended September 30,			Nine Months Ended September 30,		
Dollars in millions	**2003**	**2002**	**Change**	**2003**	**2002**	**Change**
Interest expense and dividends on preferred securities	$19.2	$21.4	$2.2	$57.3	$65.3	$8.0
Average debt outstanding (1)	$1,249.5	$1,408.7	$159.2	$1,219.7	$1,410.8	$191.1
Average rate	6.1%	6.1%	-	6.3%	6.2%	(0.1%)

(1) Includes Trust Preferred Securities

The decrease in our interest expense of $2.2 million and $8.0 million for the three and nine months ended September 30, 2003 as compared to the same periods last year was a result of lower average debt balances due primarily to the proceeds generated from our equity offering, lower long-term interest rates from our bond issuance in July, repayment of Medium-Term notes and lower interest rates on commercial paper borrowings.

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 six 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.

  AGLC operates under a three-year Performance Based Rate (PBR) plan, effective May 1, 2002, with an allowed return on equity of 11%. The PBR plan also establishes an earnings band of 10% to 12% with three-quarters of any earnings above 12% shared with the Georgia customers and one-quarter retained by AGLC. Under the PBR plan, AGLC must make minimum filing requirements and offer supporting testimony in general rate case format for rates effective May 1, 2005.

- **VNG** is a natural gas local distribution utility with distribution systems and related facilities serving eight cities and surrounding areas 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 five million gallons of propane storage capacity in its two propane facilities to supplement the supply of natural gas during peak usage periods.

  On September 27, 2002, the Virginia State Corporation Commission (VSCC) approved an experimental two-year weather normalization adjustment (WNA) program to reduce the effect of weather on customer bills. The WNA reduces bills when winter weather is colder than normal and surcharges customer bills when weather is warmer than normal. In order to extend the WNA program, VNG must file a cost of service study with the VSCC. We expect to file, in 2004, for an extension of this program.

- **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. Included in the rates charged by CGC is a WNA factor, which offsets the impact of unusually cold or warm weather on operating margin.

The Georgia Public Service Commission (GPSC) regulates AGLC; 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. We continuously monitor our utilities' performance to determine whether or not rates need to be adjusted through a rate filing.

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

	Three Months Ended September 30,			Nine Months Ended September 30,		
In millions	**2003**	**2002**	**Change**	**2003**	**2002**	**Change**
Operating revenues (1)	$159.5	$186.6	($27.1)	$661.8	$609.7	$52.1
Cost of sales	27.7	56.7	29.0	221.2	177.9	(43.3)
Operating margin	131.8	129.9	1.9	440.6	431.8	8.8
Operating expenses						
Operation and maintenance	62.1	59.3	(2.8)	193.1	188.1	(5.0)
Depreciation and amortization	20.4	19.8	(0.6)	60.7	61.8	1.1
Taxes other than income	5.8	6.2	0.4	18.9	18.7	(0.2)
Total operating expenses	88.3	85.3	(3.0)	272.7	268.6	(4.1)
Gain on sale of Caroline Street campus	21.5	-	21.5	21.5	-	21.5
Operating income (1)	65.0	44.6	20.4	189.4	163.2	26.2
Other income (1)	0.5	0.4	0.1	1.0	0.8	0.2
Donation to private foundation	(8.0)	-	(8.0)	(8.0)	-	(8.0)
EBIT	$57.5	$45.0	$12.5	$182.4	$164.0	$18.4

(1) We reclassified regulatory carrying charges from other income to operating revenues in 2003, a change which affects our Distribution Operations segment. Reconciliations of our operating income for the three and nine months ended September 30, 2002 is presented below:

In millions	Three Months Ended September 30, 2002	Nine Months Ended September 30, 2002
Operating income - as previously disclosed	$42.3	$156.3
Add regulatory carrying charges	2.3	6.9
Operating income - as revised	$44.6	$163.2

	Nine Months Ended September 30,		
Metrics	**2003**	**2002**	**% Change**
Average end-use customers (in thousands)	1,843	1,827	0.9%
Throughput (millions of dekatherms)	211	210	0.5%
Heating degree days (1):			
Georgia	1,699	1,589	6.9%
Virginia	2,271	1,799	26.2%
Tennessee	1,963	1,742	12.7%

(1) We measure the effects of weather on our businesses using "degree days." The measure of degree days for a given day is the difference between the average daily actual temperature and the baseline temperature of 65 degrees. Heating degree days result when the average daily actual temperature is less than the 65 degree baseline. Generally, increased heating degree days result in greater demand for gas on our distribution systems.

The increase in EBIT of $12.5 million for the three months ended September 30, 2003 as compared to the three months ended September 30, 2002 is primarily due to the gain of $21.5 million on the sale of the land from our Caroline Street campus, offset by the $8.0 million donation to a private foundation. Exclusive of the gain, our distribution operation segment's EBIT was $44.0 million for the quarter compared to $45.0 million for the same period last year.

Operating margin increased $1.9 million as a result of higher average usage per customer and an increase in the average number of connected customers of approximately one percent. The increase in operating margin was offset by an increase in operating expenses of $3.0 million or three percent, primarily from increased corporate overhead costs which included higher corporate building lease costs and general business insurance cost as well as in increase in benefit costs primarily related to pension and postretirement benefit plans.

The increase in EBIT of $18.4 million for the nine months ended September 30, 2003 as compared to the nine months ended September 30, 2002 was primarily due to the gain of $21.5 million on the sale of the land from our Caroline Street campus, offset by the $8.0 million donation to a private foundation. Exclusive of the gain and donation, EBIT increased $4.9 million from improved operations.

This increase in EBIT of $4.9 million was primarily a result of increased operating margin and increased operating expenses. Operating margin increased $8.8 million primarily as a result of higher usage per degree day and customer growth of $12.8 million. This increase was offset by lower customer rates of $3.3 million due to the performance based rate settlement with the GPSC effective May 1, 2002 and lower carrying cost charges on natural gas stored underground on behalf of GPSC-certificated Marketers (Marketers) of $1.8 million. Marketers are responsible for the retail sale of natural gas to end-use customers in Georgia. The retail function includes customer service, billing, collections, and the purchase and sale of the natural gas commodity.

The increase of $4.1 million in operating expenses is primarily from increased corporate overhead costs of $2.7 million which included higher corporate building lease and general business insurance costs and increased bad debt expenses of $1.9 million as a result of colder than normal 2003 heating season. These increases in operating expenses were partially offset by a $1.4 million decrease in depreciation expenses due to the performance based rate settlement effective May 1, 2002.

Wholesale Services

Our wholesale services segment includes the results of operations and financial condition of Sequent Energy Management, LP (Sequent), our asset optimization, producer services, and wholesale marketing and risk management subsidiary. Our asset optimization business focuses on capturing value from idle or underutilized natural gas assets, which are typically amassed by companies via investments in or contractual rights to natural gas transportation and storage assets. Margin is typically created in this business, by participating in transactions that balance the needs of varying markets and time horizons. Our asset management customers in this business, mainly utilities, must contract for transportation and storage services to meet their peak day demands. These customers typically contract for these services on a 365 day basis even though they may only need these services to meet their peak demands for a much shorter period. We enter into agreements with these customers, either through contract assignment or agency arrangement, whereby we utilize these transportation and storage services that they have rights to during the customers' off-peak periods. We capture margin through the optimization of the purchasing, transporting, storing and selling of the natural gas and typically either share the profits with the customer or pay a fee to the customer for using their assets.

In our wholesale marketing and risk management business we contract for our own transportation and storage services. We participate in transactions where we combine the natural gas commodity and transportation costs that will result in the lowest cost path to serve our markets. We then seek to optimize this value chain on a daily basis as market conditions change by evaluating all of the natural gas supply, transportation and markets we have access to and seek out the least cost alternatives to serve our markets. This enables us to capture locational pricing differences as they change. In a similar manner, we participate in natural gas storage transactions where we seek to find the pricing differences that occur over time. Prices for future delivery periods at many locations are readily available. We capture margin by purchasing natural gas at the lowest future price and selling it at the highest future price, all within the constraints of our contract. Through the use of transportation and storage services, we are able to capture margin through the arbitrage of locational pricing differences and by recognizing pricing differences that occur over time.

Our producer services business is primarily focused on aggregating natural gas supply from various small and medium sized producers located throughout the production areas of the United States. We provide the natural gas producers price transparency and certain risk management services that give the producers alternatives to the prices they can achieve for the commodity. By aggregating volumes of natural gas from these producers we are able to provide ready outlets to the producers who are interested in securing a reliable outlet for their natural gas production. We capture value by being able to efficiently procure a reliable pool of natural gas at reasonable prices to service our marketing portfolio.

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.
- 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 the USF.
- 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.

During 2002, our wholesale services segment accounted for derivative transactions in connection with energy marketing in accordance with SFAS No. 133 "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133) and accounted for non-derivative energy and energy-related 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:

- an adjustment to the carrying value of our non-derivative trading instruments (principally our storage capacity contracts) to zero and now we account for them using the accrual method of accounting;
- an adjustment to 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), which 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
- reclassification of 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. 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:

In millions	Three Months Ended September 30, 2003	2002	Change	Nine Months Ended September 30, 2003	2002	Change
Operating revenues	$5.6	$5.5	$0.1	$38.2	$15.0	$23.2
Cost of sales	1.3	0.1	(1.2)	1.4	0.1	(1.3)
Operating margin	4.3	5.4	(1.1)	36.8	14.9	21.9
Operating expenses						
Operation and maintenance	3.0	4.0	1.0	14.3	9.8	(4.5)
Taxes other than income	0.1	0.1	-	0.3	0.3	-
Total operating expenses	3.1	4.1	1.0	14.6	10.1	(4.5)
Operating income	1.2	1.3	(0.1)	22.2	4.8	17.4
Other loss	(0.3)	-	(0.3)	(0.3)	-	(0.3)
EBIT	$0.9	$1.3	($0.4)	$21.9	$4.8	$17.1

Metrics			% Change			% Change
Physical sales volumes (Bcf/day)	1.49	1.43	4.2%	1.72	1.29	33.3%
NYMEX (1) average settled price (2)	$4.97	$3.18	56.3%	$5.66	$2.97	90.6%

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

The decrease in EBIT of $0.4 million for the three months ended September 30, 2003 as compared to the three months ended September 30, 2002 was primarily due to unseasonably cool temperatures in the Southeast, Midwest and upper Mid-Atlantic regions during the three months ended September 30, 2003 as compared to the three months ended September 30, 2002. The third quarter of 2002 experienced the impacts of two hurricanes in the Gulf of Mexico and a heat-wave in the Northeast which increased price volatility in that quarter. In the third quarter of 2003, Sequent recorded gas inventory on an accrual basis, at the lower of cost or market, compared to the third quarter of 2002, when it recorded its gas inventory on a mark to market basis under EITF 98-10. EITF 98-10 was rescinded on October 25, 2002. Additionally, in the third quarter of 2003, Sequent recorded a lower of cost or market adjustment of $0.6 million on a portion of its gas stored inventory previously committed for sale in October, 2003. These October sales were at prices lower than Sequent's weighted average cost of gas in its inventory at September 30, 2003.

Sequent recorded unrealized gains of $2.2 million during the three months ended September 30, 2003, and $1.2 million during the three months ended September 30, 2002, related to changes in the fair value of derivative instruments used in our energy marketing and risk management activities.

The increase in EBIT of $17.1 million for the nine months ended September 30, 2003 as compared to the nine months ended September 30, 2002 was primarily due to an increase in operating margin of $21.9 million as a result of 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. During the three months ended March 31, 2003, Sequent sold substantially all of its 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 amounts shared with our affiliated local distribution companies, for transactions that were recorded on a mark-to-market basis in prior periods. The increase in operating margin was partially offset by a $4.5 million increase in operating expenses caused by a $2.5 million increase in corporate costs and $1.2 million in personnel expense primarily from growth in the business.

Also, Sequent's physical sales volumes for the nine months ended September 30, 2003 increased 33% 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 during the winter 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 during the first quarter. Since the first quarter, volatility has declined to approximately the 2002 calendar year average.

Sequent recorded unrealized gains of $8.3 million, excluding the cumulative effect of change in accounting principle, during the nine months ended September 30, 2003, and unrealized gains of $0.2 million during the nine months ended September 30, 2002 related to changes in the fair value of derivative instruments utilized in our 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 nine months ended September 30, 2003 and 2002. We also recorded energy-trading contracts, as defined under EITF 98-10, on a mark-to-market basis for the nine months ended September 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 nine months ended September 30, 2003 and 2002 and provide details of the net fair value of contracts outstanding as of September 30, 2003. Sequent's storage positions are affected by price sensitivity in the NYMEX average price.

In millions	Three Months Ended September 30, 2003	Three Months Ended September 30, 2002	Nine Months Ended September 30, 2003	Nine Months Ended September 30, 2002
Net fair value of contracts outstanding at beginning of period	$0.2	$1.9	$6.7	$2.9
Cumulative effect of change in accounting principle	-	-	(12.6)	-
Net fair value of contracts outstanding at beginning of period, as adjusted	0.2	1.9	(5.9)	2.9
Contracts realized or otherwise settled during period	(1.6)	(2.6)	(5.5)	(4.9)
Net fair value of net claims against counterparties	-	-	-	-
Change in net fair value of contracts gains (losses)	3.9	3.8	13.9	5.1
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	$2.5	$3.1	$2.5	$3.1

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	$1.2	($0.5)	$-	$-	$0.7
Prices provided by other external sources	1.7	0.1	-	-	1.8

The "prices actively quoted" category represents Sequent's positions in natural gas, which are valued exclusively using NYMEX futures prices. "Prices provided by other external sources" are basis transactions that represent the cost to transport the commodity from a NYMEX delivery point to the contract delivery point. Our basis spreads are based on quotes primarily obtained either directly from brokers or through electronic trading platforms.

Subsequent Event. In October 2003, Sequent purchased two separate asset management agreements with non affiliates in the Northeast for approximately $4.0 million. Under the terms of these agreements, one of which expires in 2006 and the other which expires in 2012, Sequent has been assigned certain natural gas transportation and storage contracts to support its obligation to supply all of the gas requirements of the customers, mainly at index prices. Additionally, Sequent will be paid a services fee. We do not believe these agreements will have a material impact on our results of operations or financial condition.

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 Inc., Piedmont Natural Gas Company (Piedmont) and Dynegy Inc. (Dynegy) to market natural gas and related services to retail customers, principally in Georgia. 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 March 11, 2003, our wholly-owned subsidiary, Georgia Natural Gas Company, purchased Dynegy's 20% ownership interest in SouthStar in a transaction that 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%. Our 70% interest is non-controlling because all significant matters require approval by both owners.

  SouthStar is the largest retail marketer of natural gas in Georgia with a market share of approximately 37% which is relatively consistent with its market share of 38% in the prior year, and operates under the trade name Georgia Natural Gas.

  SouthStar's operating policy contains a provision for the disproportionate sharing of earnings between our partner in SouthStar, Piedmont, and us when SouthStar's annual earnings before taxes exceed a certain annual threshold. The annual threshold is calculated each year based on a cumulative and annual 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 in the range of $2.3 million to $4.4 million, before taxes. This is based on our estimate that our actual earnings from SouthStar were approximately 55.7% to 60.7% of total earnings, rather than the 50% reflective of our equity ownership. We estimate our increased portion of equity earnings from SouthStar for the twelve months ending December 31, 2001 and 2000 to be up to an aggregate of $2.6 million before taxes. No disproportionate distributions have occurred to date because the partners have not reached an agreement on how the disproportionate sharing should be calculated.

  Our estimated increased portion of equity earnings for the twelve months ended December 31, 2002 is based on our interpretation of the disproportionate sharing provisions in SouthStar's operating policy. Because the estimate is still subject to change we will not record our increased portion of equity earnings until we have an agreement with Piedmont. 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 will occur again in 2003. We remain in active discussions with Piedmont to reach a resolution on the disproportionate sharing provisions.

- **US Propane** is a joint venture formed in 2000 by subsidiaries of AGL Resources Inc., Atmos Energy Corporation, Piedmont 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 Propane Partners, L.P. (Heritage), a publicly traded marketer of propane.

- **AGL Networks**, our wholly-owned subsidiary, is a carrier-neutral provider, which leases telecommunications fiber 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 offers telecommunications construction services to others.

  In the third quarter of 2003, AGL Networks determined that it would focus on the wholesale telecommunications customer. In particular, these customers would utilize our network to provide a bundled service to commercial entities. Our primary goals for this business in the next 12 to 15 months are:
  - to increase revenues through our sales efforts to achieve break even or better results by the end of 2004,
  - to maintain control of capital costs for connecting carriers to the network, and
  - to reduce sales expenses.

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

In millions	Three Months Ended September 30, 2003	Three Months Ended September 30, 2002	Change	Nine Months Ended September 30, 2003	Nine Months Ended September 30, 2002	Change
Operating revenues	$1.2	$1.1	$0.1	$5.3	$1.6	$3.7
Cost of sales	0.2	0.2	-	0.6	0.5	(0.1)
Operating margin	1.0	0.9	0.1	4.7	1.1	3.6
Operating expenses						
Operation and maintenance	2.2	1.6	(0.6)	7.5	5.1	(2.4)
Depreciation and amortization	0.4	0.1	(0.3)	0.6	0.1	(0.5)
Taxes other than income	0.1	-	(0.1)	0.4	0.1	(0.3)
Total operating expenses	2.7	1.7	(1.0)	8.5	5.3	(3.2)
Operating income	(1.7)	(0.8)	(0.9)	(3.8)	(4.2)	0.4
Other income (loss)	5.7	(2.4)	8.1	30.4	22.3	8.1
EBIT	$4.0	($3.2)	$7.2	$26.6	$18.1	$8.5

Metrics:	Nine Months Ended September 30, 2003	Nine Months Ended September 30, 2002
SouthStar		
Average Customers (in thousands)	564	568
Volumes (millions of dekatherms)	47	49
AGL Networks		
% Dark fiber miles leased - Atlanta	9.9%	3.0%
% Dark fiber miles leased – Phoenix	4.6%	-

The increase in EBIT of $7.2 million for the three months ended September 30, 2003 as compared to the three months ended September 30, 2002 is primarily the result of increased earnings from SouthStar. The increase in earnings from SouthStar of $7.5 million is primarily the result of higher margins and decreased bad debt and operating expenses and our additional 20% ownership interest as a result of our purchase of Dynegy's interest in the business earlier this year.

The increase in EBIT of $8.5 million for the nine months ended September 30, 2003 as compared to the nine months ended September 30, 2002 is primarily the result of increased earnings from SouthStar of $6.4 million and US Propane of $1.4 million. The increased contribution from SouthStar is primarily due to higher volumes, the additional 20% ownership interest and lower bad debt and operating expenses. The increased contribution from US Propane is primarily due to colder weather as compared to last year.

AGL Networks' operating margin increase of $3.6 million for the nine months ended September 30, 2003, primarily as a result of increased monthly recurring contract revenues and a $2.3 million sales-type lease in the first quarter of 2003. This was offset by increased operating expenses of $3.2 million, mostly from additional operating expenses due to business growth, and higher corporate overhead costs. Our net investment in AGL Networks is approximately $27.8 million at September 30, 2003.

Corporate

Our corporate segment includes the results of operations and financial condition of our nonoperating business units, including AGL Services Company (AGSC) and AGL Capital Corporation (AGL Capital). AGSC 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 AGSC'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:

In millions	**Three Months Ended September 30, 2003**	**2002**	**Change**	**Nine Months Ended September 30, 2003**	**2002**	**Change**
Operating revenues	$-	($0.2)	$0.2	$0.1	($0.2)	$0.3
Cost of sales	-	-	-	-	-	-
Operating margin	-	(0.2)	0.2	0.1	(0.2)	0.3
Operating expenses						
Operation and maintenance	(1.7)	4.2	5.9	(7.2)	1.5	8.7
Depreciation and amortization	2.8	1.5	(1.3)	7.3	5.1	(2.2)
Taxes other than income	(0.4)	0.8	1.2	1.6	2.7	1.1
Total operating expenses	0.7	6.5	5.8	1.7	9.3	7.6
Write-off on sale of Caroline Street campus	(5.6)	-	(5.6)	(5.6)	-	(5.6)
Operating loss	(6.3)	(6.7)	0.4	(7.2)	(9.5)	2.3
Other loss	(0.4)	(0.4)	-	(1.2)	(0.9)	(0.3)
EBIT	($6.7)	($7.1)	$0.4	($8.4)	($10.4)	$2.0

The increase in EBIT of $0.4 million for the three months ended September 30, 2003 as compared to the three months ended September 30, 2002 is primarily the result of the write-off of $5.6 million on the sale of the buildings and their contents on Caroline Street campus offset by a $6.4 million charge for the termination of the automated meter reading contract in the prior year.

The increase in EBIT of $2.0 million for the nine months ended September 30, 2003 as compared to the nine months ended September 30, 2002 is primarily the result of the items mentioned above and prior year accrued expenses that were not allocated to our operating segments.

Liquidity and Capital Resources

We rely on operating cash flow, along with borrowings under our commercial paper program backed by our Credit Facility, for our short-term liquidity and capital resource requirements. Our availability of borrowings under our Credit Facility is subject to conditions specified within the Credit Facility, which we currently meet. These conditions include our compliance with certain financial covenants 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, debt service obligations and scheduled capital expenditures. 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 ratio, as represented in the following table.

	As of	
In millions	September 30, 2003	December 31, 2002
Unused availability under our Credit Facility	$500.0	$244.1
Cash and cash equivalents	1.0	8.4
Total cash and available liquidity under our Credit Facility	$501.0	$252.5

As a result of our borrowing of long-term debt and our equity offering our total cash and available liquidity under our Credit Facility at September 30, 2003 increased $248.5 million from December 31, 2002. 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 us. As of September 30, 2003 Sequent's unsecured line of credit had approximately $8.8 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 flow from operations generated $101.1 million for the nine months ended September 30, 2003, a decrease of $131.6 million for the same period last year. Year-to-year changes in operating cash flow result largely from fluctuations in working capital items occurring mainly in the distribution operations segment due to factors such as weather, the price of natural gas, the timing of collections from customers and gas purchasing practices. Our cash and cash equivalents were $1.0 million as of September 30, 2003, a decrease of $7.4 million from December 31, 2002. Our principal sources and uses of cash during the nine months ended September 30, 2003 are summarized below:

Sources

- Our cash flow from operations was $101.1 million, which was positively impacted by the collection of our receivables of $148.9 million as a result of seasonality. This was offset by cash used to increase our natural gas inventories by $135.9 million, primarily to inject natural gas into our inventories to prepare for the upcoming heating season and to purchase storage gas owned by the Marketers and $43.3 million of cash used to decrease our trade payables, which funded increased natural gas purchases.
- We received $225.0 million from our Senior Note borrowings.
- We received $136.7 million from our equity offering.
- We received $22.7 million from the sale of our Caroline Street campus.
- We received $18.9 million from our sale of treasury stock.
- We received $7.5 million from our other investing and financing activities.

Uses

- We paid $261.4 million (net of borrowings) to reduce our outstanding short-term debt from the commercial paper program.
- We invested $112.6 million in property, plant and equipment.
- We paid $72.5 million in scheduled and early payments on our Medium-Term notes.
- We paid $52.8 million in cash dividends on our common stock.
- We invested $20.0 million in our purchase of Dynegy's 20% interest in SouthStar.

As of September 30, 2002, our cash and cash equivalents were $6.1 million, a decrease of $1.2 million from December 31, 2001. Our principal sources and uses of cash during the nine months ended September 30, 2002 are summarized below:

Sources

- We generated cash flow from operations of $232.7 million, which was positively impacted by the increase in our payables net of the increase in our receivables of $32.6 million, primarily as a result of growth in transaction volumes in our wholesale services segment. Additionally, we received cash of $49.5 million from the sale of natural gas inventories, primarily storage gas sold to the Marketers, in excess of cash purchases.
- We received $12.8 million from our sale of treasury stock.
- We received $26.3 million from our investments in SouthStar and Heritage.
- We received $3.3 million from our other investing and financing activities.

Uses

- We invested $121.3 million in property, plant and equipment.
- We paid $64.6 million (net of borrowings) to reduce our outstanding short-term debt from the commercial paper program.
- We paid $45.4 million in cash dividends on our common stock.
- We paid $45.0 million in scheduled payments on our Medium-Term notes.

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 September 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:

	As of:			
Dollars in millions	September 30, 2003		December 31, 2002	
Short-term debt	$127.2	5.8%	$388.6	18.3%
Current portion of long-term debt	42.0	1.9	30.0	1.4
Senior and Medium Term notes (1)	903.5	40.9	767.0	36.1
Trust Preferred Securities (2)	226.7	10.3	227.2	10.7
Total debt	1,299.4	58.9	1,412.8	66.5
Common equity	908.5	41.1	710.1	33.5
Total capitalization	$2,207.9	100.0%	$2,122.9	100.0%

(1) Net of interest rate swaps of ($4.0) million as of September 30, 2003.
(2) Net of interest rate swaps of $4.8 million and $6.1 million.

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; and a $300 million 3 year Credit Facility that terminates on August 7, 2005. As of October 25, 2003, we had no outstanding borrowings under the Credit Facility. The following table provides details on AGL Capital's commercial paper program:

	Three Months Ended September 30,		Nine Months Ended September 30,	
In millions, except interest rates	2003	2002	2003	2002
Average outstanding balance	$62.9	$337.7	$142.8	$323.6
Weighted-average interest rate	1.2%	2.1%	1.5%	2.3%

Sequent has a $15.0 million unsecured line of credit, which is used solely for the posting of margin deposits for New York Mercantile Exchange transactions, and is unconditionally guaranteed by AGL Resources Inc. 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 September 30, 2003, the line of credit had an outstanding balance of $6.2 million. The following table provides details on Sequent's line of credit:

	Three Months Ended September 30,		Nine Months Ended September 30,	
In millions, except interest rates	2003	2002	2003	2002
Average outstanding balance	$8.1	$1.0	$4.6	$2.2
Weighted-average interest rate	1.5%	2.3%	1.6%	2.3%

Long-term Debt. In October 2003, we expect to make the following Medium-Term note payments using proceeds from the commercial paper program:

- $30.0 million for scheduled Medium-Term note payments due in October 2003, with an interest rate of 5.90%;
- $10.0 million for Medium-Term note bearing interest of 6.0%, exercised at par before its scheduled October 2006 maturity date; and
- $2.0 million for Medium-Term note bearing interest of 6.85%, exercised at a premium before its scheduled October 2023 maturity date.

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 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 5 *"Risk Management."*

Shelf Registration. On September 23, 2003, we filed a shelf registration with the SEC for authority to issue up to $1.0 billion of various capital securities. This registration statement is inclusive of the unused amount of approximately $383 million from our $750 million registration statement filed on September 17, 2001.

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 nine months ended September 30, 2003 no fundamental adverse shift occurred in our ratings profile.

The following table presents, as of October 24, 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 and covenants.

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 $4.7 million. We believe the existing cash and available liquidity under our Credit Facility is adequate to fund these potential liquidity requirements.

Capital Requirements

Capital Expenditures for the nine months ended September 30, 2003 were $112.6 million, a decrease of $8.7 million or 7.2 percent from the same period last year. The decrease of $8.7 million is primarily from lower expenditures at our energy investments segment of $9.8 million, as a result of the completion of the metro Atlanta fiber network last year and a decrease of $4.4 million associated with our distribution operations segment. These decreases were offset by higher capital expenditures at our corporate segment of $6.8 million due to expenditures incurred while moving to our new corporate headquarters.

For a discussion on our contractual cash obligations and other commercial commitments, see Item 1, Financial Statements, Note 8 *"Commitments and Contingencies."*

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 recorded a long-term liability of $344.6 million as of September 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. These estimates are reported on an undiscounted basis. The pipeline replacement program ordered by the GPSC to be administered by AGLC requires, among other things, that AGLC replace all bare steel and cast iron pipe in AGLC's system in the state of Georgia within a 10-year period, beginning October 1, 1998. AGLC identified and provided to the GPSC in accordance with this order 2,312 miles of bare steel and cast iron pipe to be replaced. If AGLC does not perform in accordance with this order, AGLC will be assessed certain non-performance penalties. The order also provides for recovery of all prudent costs incurred in the performance of the program, which AGLC has recorded as a regulatory asset. The regulatory asset has two components:

- the costs incurred to date that have not yet been recovered through this rate rider; and
- the future expected costs to be recovered through this rate rider.

As of September 30, 2003, AGLC had recorded a current liability of $74.2 million, representing expected pipeline replacement program expenditures for the next 12 months.

Environmental Response Costs

AGLC historically reported estimates of future remediation costs based on probabilistic models of potential costs. These estimates are reported on an undiscounted basis. 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 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 June 30, 2003, for those elements of the MGP program with in-place contracts or engineering cost estimates is $72.8 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 estimated remaining cost of future actions at the MGP sites is in the range of $15.2 million to $27.5 million. AGLC cannot estimate any single number within this range as a better estimate of its likely future costs. As a result, we accrued the lower end of the range, or $15.2 million, for these remaining elements. Finally, AGLC has estimates of certain other costs paid directly by AGLC related to administering the MGP program and the remediation of sites currently in investigation phase. Through January 2005, AGLC estimates the administration costs to be $2.7 million. Finally, there remains considerable variability in the estimates of costs related to the administering of the MGP program and the remediation of sites currently in investigation phase after January 2005. For those elements, the estimate ranges from $9.0 million to $14.6 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 $9.0 million for these remaining elements. Consequently, as of September 30, 2003 and December 31, 2002, AGLC's environmental response cost liability is comprised of:

	As of:		
	September 30, 2003	December 31, 2002	Change
Projected engineering estimates and in-place contracts	$72.8	$109.2	($36.4)
Estimated future remediation costs	15.2	9.3	5.9
Administration expenses	2.7	1.3	1.4
Other expenses	9.0	-	9.0
Cash payments for clean-up expenditures	(5.1)	(14.8)	9.7
Accrued environmental response costs	$94.6	$105.0	($10.4)

The environmental response cost liability is included in a corresponding regulatory asset. As of September 30, 2003, the regulatory asset was $187.3 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 any potential cost savings from the new cleanup technologies references 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 operating margins. VNG's weather normalization factor was introduced in November 2002 as 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 these settlements as receivables and payables 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 that consensus, we present gains and losses from energy-trading activities on a net basis. 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), 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 recognizes revenues from sales of natural gas and transportation services in the same period in which it delivers 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 recognizes 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 legal title to the 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 changes in the facts or expectations 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 corporate bond rates at historic low levels 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 whole or in part under future rate proceedings or mechanisms.

Equity market performance and corporate bond rates have a significant effect on our reported unfunded ABO as the primary factors that drive the value of our unfunded ABO are the assumed discount rate and the actual return on plan assets. Additionally, equity market performance has a significant effect on our market-related value of plan assets (MRVPA), which is a calculated value and differs from the actual market value of plan assets. The MRVPA recognizes the differences between the actual market value and expected market value of our plan assets and is determined by our actuaries using a five-year moving weighted-average methodology. Gains and losses on plan assets are spread through the MRVPA based on the five-year moving weighted-average methodology, which affects the expected return on plan assets component of pension expense.

A one percentage point increase or decrease in the assumed discount rate could have a negative or positive impact on 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 September 30, 2003, the market value of the pension assets was $232.5 million as compared to a market value of $207.8 million as of December 31, 2002. The net increase of $24.7 million from December 31, 2002 to September 30, 2003 resulted from:

- our contribution of $6.5 million on February 14, 2003;
- our contribution of $5.5 million on September 15, 2003; and
- our actual return on plan assets of $27.8 million less benefits paid of $15.1 million.

Our $12.0 million in contributions this year is expected to reduce pension expense by approximately $0.7 million for the twelve months ended December 31, 2003. The actual return on plan assets 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.

Accounting Developments

In January 2003, the FASB issued FASB Interpretation No. 46, "Consolidation of Variable Interest Entities," (FIN 46) which requires the primary beneficiary of a variable interest entity's activities to consolidate the variable interest entity. The primary beneficiary is the party that absorbs a majority of the expected losses and/or receives a majority of the expected residual returns of the variable interest entity's activities. FIN 46 is immediately applicable to variable interest entities created, or interests in variable interest entities obtained, after January 31, 2003. For variable interest entities created, or interests in variable interest entities obtained, on or before January 31, 2003, FIN 46 is now required to be applied in the first fiscal year or interim period beginning after September 15, 2003, a three month delay from the original effective date of the first annual or interim period beginning after June 15, 2003. FIN 46 may be applied prospectively with a cumulative-effect adjustment as of the date it is first applied, or by restating previously issued financial statements with a cumulative-effect adjustment as of the beginning of the first year restated. FIN 46 also requires certain disclosures of an entity's relationship with variable interest entities.

We are currently evaluating the impact, if any, of FIN 46 on our Trust Preferred Securities, which may include deconsolidating the trust and reclassifying the trust as a liability. We are awaiting further guidance on this matter from the FASB's deliberations on this issue. We currently classify amounts related to the Trust Preferred Securities as long-term debt in our condensed consolidated balance sheets.

In April 2003, the FASB issued SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities," (SFAS 149) which amends and clarifies financial accounting and reporting for derivative instruments and for hedging activities, including the qualifications for the normal purchases and normal sales exception, under SFAS 133. The amendment reflects decisions made by FASB in connection with issues raised about the application of SFAS 133. Generally, the provisions of SFAS 149 will be applied prospectively for contracts entered into or modified after June 30, 2003, and for hedging relationships designated after June 30, 2003. Our adoption of SFAS 149 did not have a material effect on our condensed consolidated results of operations, cash flows or financial position.

In May 2003, the FASB issued SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity," (SFAS 150) which establishes standards for classification and measurement of certain financial instruments with characteristics of both liabilities and equities. Under SFAS 150, such financial instruments are required to be classified as liabilities in the statement of financial position. The financial instruments affected include mandatorily redeemable stock, certain financial instruments that require or may require the issuer to buy back some of its shares in exchange for cash or other assets, and certain obligations that can be settled with shares of stock. SFAS 150 is effective for all financial instruments entered into or modified after May 31, 2003 and was applied to our existing financial instruments beginning on July 1, 2003. Our adoption of SFAS 150 did not have a material effect on our condensed consolidated results of operations, cash flows or financial position.

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 the OPS fails to do that, then there are identified requirements within the Act that 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. The Act 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

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. Most recently, AGLC 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 stipulation 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 that underlie the sales services provided to the Marketers on its distribution system under GPSC approved tariffs.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to risks associated with commodity prices, interest rates and credit. Commodity price risk is defined as the 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.

The 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 approval and authorization levels and delegation of these 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. Our wholesale services segment routinely utilizes various types of financial and other instruments to mitigate certain commodity price risks inherent in the natural gas industry. 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 or other contractual arrangements. We do not designate our derivative instruments that manage our 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 289.9 Bcf and sales (short) of 309.1 Bcf.

The following table includes the fair values and average values of our energy marketing and risk management assets and liabilities as of September 30, 2003 and December 31, 2002. We base the average values on a monthly averages for the nine months ended September 30, 2003.

	Asset			
	Average Values		Value at:	
In millions	Three Months	Nine Months	Sept. 30, 2003	Dec. 31, 2002
Natural gas contracts	$12.5	$14.3	$10.2	$24.7

	Liability			
	Average Values		Value at:	
In millions	Three Months	Nine Months	Sept. 30, 2003	Dec. 31, 2002
Natural gas contracts	$10.7	$15.4	$7.7	$17.9

We employ a systematic approach to the evaluation and management of the risks associated with our 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. We use both a 1-day and 20-day holding and a 95% confidence interval to evaluate our 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.

We calculate 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. Our 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 underlying such calculations.

Our open exposure is managed in accordance with established policies that limit market risk and require daily reporting of potential financial exposure to senior management, including the chief risk officer. Because we generally manage physical gas assets and economically protect our positions by hedging in the futures markets, our open exposure is generally minimal, permitting us to operate within relatively low VaR limits. We employ daily risk testing using both VaR and stress testing to evaluate the risks of our open positions.

Our management actively monitors open commodity positions and the resulting VaR. We continue to maintain a relatively matched book, where total buy volume is close to sell volume, with minimal open commodity risk. Based on a 95% confidence interval and employing a 1-day and a 20-day holding period for all positions, our portfolio of positions for the three and nine months ended September 30, 2003 had 1-day and 20-day holding period VaRs of:

	1-day	20-day
Period end	$0.1	$0.2
Three-month average	0.1	0.2
Nine-month average	0.1	0.3
High	0.3	1.2
Low (1)	0.0	0.0

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

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 on an accrual basis, 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 current accounting guidance, we would recognize a loss in any period when the market price for gas is lower than the 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 September 30, 2003, a $0.10 forward NYMEX price change would result in a $0.5 million impact to Sequent's EBIT.

Sequent manages underground storage for our utilities and holds certain capacity rights on its own behalf. The underground storage is of two types:

- reservoir storage, where supplies are generally injected and withdrawn on a seasonal basis; and
- salt dome high-deliverability storage, where supplies may be periodically injected and withdrawn on relatively short notice.

As of September 30, 2003, Sequent's stored gas inventory portfolio was scheduled to be sold almost entirely within the next six months. We expect to sell approximately 47% in the fourth quarter of 2003 with the remainder scheduled to be sold in the first quarter of 2004. Since Sequent actively manages and optimizes its portfolio, it may change its scheduled injection and withdrawal plans based on market conditions. Therefore, we cannot predict that our actual inventory withdrawals will match the planned schedule as of September 30, 2003. However, since substantially all differences between injection and withdrawal prices are locked-in through the use of derivatives, there are no significant permanent earnings impact associated with changes in monthly prices in the interim between injection and withdrawal. Moreover, any change in the timing of planned injections or withdrawals from one time period to another is generally conducted to enhance the future profitability of the storage position. Additionally, Sequent monitors and adjusts the amount of storage capacity it holds on a discretionary basis.

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. For derivative transactions that are designated and qualify as cash flow hedges, 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 to variable rate debt ratios, 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	September 30, 2003	December 31, 2002
$75.0	8.0%	3 Month LIBOR Plus 131.5 bps	May 15, 2041	$4.8	$6.1
$100.0	7.1%	6 Month LIBOR Plus 340.0 bps	January 14, 2011	(0.8)	$-
$100.0	4.5%	6 Month LIBOR Plus 61.5 bps	April 15, 2013	(3.2)	$-

AGL Resources' variable-rate debt consists of commercial paper, Sequent's line of credit and the swapped portions of the $300.0 million Senior Notes due 2011, $225 million Senior Notes dues 2013, and $150.0 million Trust Preferred Securities, which totaled $121.0 million, $6.2 million and $275.0 million, respectively, as of September 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 September 30, 2003 would result in a change in annual pre-tax expense or cash flows of $4.0 million. As of September 30, 2003, $42.0 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 where we charge out and collect from Marketers and poolers, costs for our distribution operations segment. AGLC bills ten Marketers in Georgia for these services, and credit risk exposure to Marketers varies with the time of the year. Our exposure is lowest in the non-peak summer months and highest in the peak winter months. Marketers are responsible for the retail sale of natural gas to end-use customers in Georgia. These retail functions include customer service, billing, collections, and the purchase and sale of the natural gas commodity. These Marketers, in turn, bill end-use customers. 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. For the nine months ended September 30, 2003, the four largest Marketers based on customer count, one of which is our partially-owned affiliate, accounted for approximately 58% of our operating margin and 64% of distribution operations' operating margin.

In addition, AGLC bills intrastate delivery service to the Marketers in advance rather than in arrears. We require security support in the form of cash deposits, letters of credit/surety bonds from acceptable issuers or 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 a Marketer fails 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.

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. When we are engaged in more than one outstanding derivative transaction with the same counterparty and we also have a legally enforceable netting agreement with that counterparty, the "net" mark-to-market exposure represents the netting of the positive and negative exposures with that counterparty and a reasonable measure of our credit risk. Our policy uses other netting agreements with certain counterparties with which we conduct significant transactions.

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 Baa3 from Moody's and BBB- from S&P. We require credit enhancements by way of guaranty, cash deposit or letter of credit for transaction counterparties that do not have either of the above ratings.

Sequent, which provides services to marketers and utility and industrial customers, also has a concentration of credit risk which is measured by 30 day receivable exposure plus forward exposure. Sequent's top 20 counterparties represent approximately 76% of the total counterparty exposure of $115 million, derived by adding the top 20 counterparties' exposures and dividing by the total counterparties' exposures.

As of September 30, 2003, Sequent's counterparties, or the counterparties' guarantors, had a weighted average Standard & Poor's (S&P) equivalent credit rating of BBB compared to BBB+ at December 31, 2002. The S&P equivalent credit rating is determined by a process of converting the lower of the S&P or Moody's ratings to an internal rating ranging from 9 to 1, with 9 being equivalent to AAA/Aaa by S&P and Moody's and 1 being D or Default by S&P and Moody's. A counterparty that does not have an external rating will be assigned an internal rating based on the strength of the financial ratios of the counterparty. The assigned internal rating is multiplied by the counterparty's credit exposure and summed, then divided by the aggregate total counterparties exposures. This numeric value is converted to an S&P equivalent. The following table shows Sequent's commodity receivable and payable positions as of September 30, 2003 and December 31, 2002:

Gross receivable	As of:		
In millions	September 30, 2003	December 31, 2002	Change
Receivables with netting agreements in place:			
Counterparty is investment grade	$176.6	$188.2	($11.6)
Counterparty is non-investment grade	10.9	22.8	(11.9)
Counterparty has no external rating	2.7	25.1	(22.4)
Receivables without netting agreements in place:			
Counterparty is investment grade	4.2	3.7	0.5
Counterparty is non-investment grade	0.1	0.4	(0.3)
Counterparty has no external rating	-	-	-
Amount recorded on balance sheet	$194.5	$240.2	($45.7)

Gross payable	As of:		
In millions	September 30, 2003	December 31, 2002	Change
Payables with netting agreements in place:			
Counterparty is investment grade	$152.4	$139.8	$12.6
Counterparty is non-investment grade	38.8	36.6	2.2
Counterparty has no external rating	25.8	28.4	(2.6)
Payables without netting agreements in place:			
Counterparty is investment grade	17.0	37.4	(20.4)
Counterparty is non-investment grade	-	2.2	(2.2)
Counterparty has no external rating	7.6	6.3	1.3
Amount recorded on balance sheet	$241.6	$250.7	($9.1)

Energy Investments. SouthStar has a year-to-date average of approximately 564,300 customers, comprising approximately 37% of the Georgia residential market. SouthStar has established the following credit guidelines and risk management practices 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

(a) *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-15(e) and 15d-15(e)) as of the end of the period covered by this quarterly report 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 have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

PART II – OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

The nature of our business 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. The city of 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 MGP 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 our 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 other 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

None.

ITEM 5. OTHER INFORMATION

None.

PART II -- OTHER INFORMATION - Continued

ITEM 6. EXHIBITS AND REPORTS ON FORM 8-K

(a) Exhibits

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

32 Section 1350 Certifications

(b) Reports on Form 8-K.

Date	Event Reported
July 2, 2003	Furnished, under Item 9 – Regulation FD Disclosure.
July 31, 2003	Furnished, under Item 5 – Other Events and Item 12 – Results of Operation and Financial Condition.
July 31, 2003	Furnished, under Item 9 – Regulation FD Disclosure.
August 28, 2003	Furnished, under Item 9 – Regulation FD Disclosure.
August 28, 2003	Furnished, under Item 9 – Regulation FD Disclosure.
September 23, 2003	Filed, under Item 5 – Other Events and Item 7 – Financial Statements and Exhibits.

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: October 30, 2003

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