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 March 31, 2004

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

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

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

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

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

Class	Outstanding as of April 23, 2004
Common Stock, $5.00 Par Value	64,806,872

AGL RESOURCES INC.

Form 10-Q

For the Quarterly Period Ended March 31, 2004

TABLE OF CONTENTS

GLOSSARY OF KEY TERMS

AGLC	Atlanta Gas Light Company
AGL Capital	AGL Capital Corporation
AGL Networks	AGL Networks, LLC
AGSC	AGL Services Company
CGC	Chattanooga Gas Company
Corporate	Nonoperating segment, which includes AGSC, AGL Capital and Pivotal
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 that includes operating income, other income, equity in SouthStar's income in 2003, donations, minority interest in 2004 and gain on sales of assets. Excludes interest and tax expense; as an indicator of our operating performance, EBIT should not be considered an alternative to, or more meaningful than, operating income or net 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
ERC	Environmental response costs
FASB	Financial Accounting Standards Board
GAAP	Accounting principles generally accepted in the United States of America
GPSC	Georgia Public Service Commission
LNG	Liquefied natural gas
Marketers	Georgia Public Service Commission-certificated marketers selling retail natural gas in Georgia
Medium-Term notes	Notes issued by AGLC scheduled to mature in 2004 through 2027 bearing interest rates ranging from 5.9% to 8.7%
MGP	Manufactured gas plant
NYMEX	New York Mercantile Exchange, Inc.
OCI	Other comprehensive income
Operating margin	A non-GAAP measure of income, calculated as revenues minus cost of gas, that excludes operation and maintenance expense, depreciation and amortization, taxes other than income taxes, and the gain on the sale of our Caroline Street campus; these items are included in our calculation of operating income as reflected in our statements of consolidated income; operating margin should not be considered an alternative to, or more meaningful than, operating income or net income as determined in accordance with GAAP
PGA	Purchased gas adjustment
Pivotal	Pivotal Energy Development
PRP	Pipeline replacement program
PUHCA	Public Utility Holding Company Act of 1935, as amended
RMC	AGL Resources' Risk Management Committee
SEC	Securities and Exchange Commission
Sequent	Sequent Energy Management, L.P.
Senior notes	Notes issued by AGL Capital scheduled to mature in 2011 through 2013 bearing interest rates ranging from 4.45% to 7.125%
SFAS	Statement of Financial Accounting Standards
SouthStar	SouthStar Energy Services LLC
Trust Preferred Securities	Trust preferred securities subject to mandatory redemption
Trusts	AGL Capital Trust I and AGL Capital Trust II
US Propane	US Propane LP
VNG	Virginia Natural Gas, Inc.
VSCC	Virginia State Corporation Commission
Wholesale services	Segment that consists primarily of Sequent
WNA	Weather normalization adjustment

REFERENCED ACCOUNTING STANDARDS

APB 25	Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees"
EITF 99-02	Emerging Issues Task Force Issue No. 99-02, "Accounting for Weather Derivatives"
EITF 00-11	Emerging Issues Task Force 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	Emerging Issues Task Force Issue No. 02-03, "Issues Involved in Accounting for Contracts under EITF Issue No. 98-10, 'Accounting for Contracts Involved in Energy Trading and Risk Management Activities'"
FIN 45	FASB Interpretation No. (FIN) 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others"
FIN 46 & FIN 46R	FASB Interpretation No. 46, "Consolidation of Variable Interest Entities"
FSP 106-1	FASB Staff Position No. 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003"
SFAS 5	SFAS No. 5, "Accounting for Contingencies"
SFAS 66	SFAS No. 66, "Accounting for Sales of Real Estate"
SFAS 71	SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation"
SFAS 123	SFAS No. 123, "Accounting for Stock-Based Compensation"
SFAS 133	SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities"
SFAS 148	SFAS No. 148, "Accounting for Stock-Based Compensation-Transition and Disclosure-an amendment of FASB Statement No. 123"

Item 1. Financial Statements

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

In millions	March 31, 2004	December 31, 2003
Current assets		
Cash and cash equivalents	$50.9	$16.5
Receivables (less allowance for uncollectible accounts of $17.4 million at March 31, 2004 and $2.5 million at December 31, 2003)	420.5	399.7
Unbilled revenues	76.5	39.9
Inventories	127.7	209.4
Energy marketing and risk management assets	32.5	13.1
Unrecovered environmental response costs – current	25.1	24.5
Unrecovered pipeline replacement program costs – current	22.9	22.1
Other current assets	8.1	22.1
Total current assets	764.2	747.3
Property, plant and equipment		
Property, plant and equipment	3,428.1	3,402.2
Less accumulated depreciation	1,052.6	1,049.8
Property, plant and equipment-net	2,375.5	2,352.4
Deferred debits and other assets		
Unrecovered pipeline replacement program costs	402.6	409.7
Goodwill	176.6	176.6
Unrecovered environmental response costs	154.9	154.9
Investments in Trusts	9.9	-
Unrecovered postretirement benefit costs	9.3	9.4
Investments in equity interests	1.8	101.3
Other	31.0	26.2
Total deferred debits and other assets	786.1	878.1
Total assets	$3,925.8	$3,977.8

See Notes to Condensed Consolidated Financial Statements (Unaudited).

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

In millions, except share amounts	March 31, 2004	December 31, 2003
Current liabilities		
Payables	$447.6	$402.7
Short-term debt	99.6	306.4
Accrued pipeline replacement program costs – current	93.3	81.6
Accrued expenses	68.8	54.1
Accrued environmental response costs – current	50.8	40.3
Current portion of long-term debt	33.5	77.0
Energy marketing and risk management liabilities	21.6	17.3
Other current liabilities	111.3	75.0
Total current liabilities	926.5	1,054.4
Accumulated deferred income taxes	392.8	376.3
Long-term liabilities		
Accrued pipeline replacement program costs	303.8	322.7
Accumulated removal costs	103.5	102.4
Accrued postretirement benefit costs	51.0	51.0
Accrued pension obligations	39.1	38.5
Accrued environmental response costs	29.0	42.7
Other	10.3	11.1
Total long-term liabilities	536.7	568.4
Deferred credits	70.8	77.3
Commitments and contingencies (Note 7)		
Minority interest	26.9	-
Capitalization		
Senior and Medium-Term notes	733.3	730.8
Notes payable to Trusts	236.9	-
Subsidiaries' obligated mandatorily redeemable preferred securities	-	225.3
Total long-term debt	970.2	956.1
Common shareholders' equity, $5 par value; 750,000,000 shares authorized	1,001.9	945.3
Total capitalization	1,972.1	1,901.4
Total liabilities and capitalization	$3,925.8	$3,977.8

See Notes to Condensed Consolidated Financial Statements (Unaudited).

AGL RESOURCES INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
FOR THE THREE MONTHS ENDED MARCH 31, 2004 AND 2003
(UNAUDITED)

In millions, except per share amounts	2004	2003
Operating revenues	$651.0	$352.5
Operating expenses		
Cost of gas	392.8	148.6
Operation and maintenance expenses	92.9	72.2
Depreciation and amortization	24.2	22.3
Taxes other than income	7.9	7.9
Total operating expenses	517.8	251.0
Operating income	133.2	101.5
Equity in earnings of SouthStar Energy Services LLC	-	14.4
Other income	0.5	1.7
Interest expense and preferred stock dividends	(15.9)	(19.9)
Minority interest in income of consolidated subsidiary	(11.0)	-
Earnings before income taxes	106.8	97.7
Income taxes	41.1	38.1
Income before cumulative effect of change in accounting principle	65.7	59.6
Cumulative effect of change in accounting principle, net of taxes	-	(7.8)
Net income	$65.7	$51.8
Basic earnings per common share		
Income before cumulative effect of change in accounting principle	$1.02	$0.99
Cumulative effect of change in accounting principle	-	(0.13)
Basic earnings per common share	$1.02	$0.86
Diluted earnings per common share		
Income before cumulative effect of change in accounting principle	$1.00	$0.98
Cumulative effect of change in accounting principle	-	(0.13)
Diluted earnings per common share	$1.00	$0.85
Weighted-average number of common shares outstanding		
Basic	64.6	60.3
Diluted	65.4	60.7

See Notes to Condensed Consolidated Financial Statements (Unaudited).

AGL RESOURCES INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY
FOR THE THREE MONTHS ENDED MARCH 31, 2004
(UNAUDITED)

In millions, except per share amounts	Common Stock Shares	Common Stock Amount	Premium on common shares	Earnings reinvested	Other Comprehensive income	Treasury stock	Total
Balance as of Dec. 31, 2003	64.5	$322.5	$325.7	$337.9	($40.4)	($0.4)	$945.3
Comprehensive income:							
Net income	-	-	-	65.7	-	-	65.7
Unrealized gain on marketable equity securities held for sale (net of tax of $0.3)	-	-	-	-	0.5	-	0.5
Unrealized gain from hedging activities	-	-	-	-	0.3	-	0.3
Total comprehensive income	-	-	-	-	-	-	66.5
Dividends on common shares ($0.28 per share)	-	-	-	(19.0)	-	-	(19.0)
Benefit, stock compensation, dividend reinvestment and share purchase plans ($28.99 weighted average price per share)	0.3	1.4	7.7	-	-	-	9.1
Balance as of March 31, 2004	64.8	$323.9	$333.4	$384.6	($39.6)	($0.4)	$1,001.9

See Notes to Condensed Consolidated Financial Statements (Unaudited).

AGL RESOURCES INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE THREE MONTHS ENDED MARCH 31, 2004 AND 2003
(UNAUDITED)

In millions	2004	2003
Cash flows from operating activities		
Net income	$65.7	$51.8
Adjustments to reconcile net income to net cash flow provided by operating activities		
Depreciation and amortization	24.2	22.3
Cumulative effect of accounting change	-	12.6
Deferred income taxes	16.5	17.5
Equity in earnings of unconsolidated affiliates	(0.2)	(15.9)
Other	(0.3)	(0.3)
Changes in certain assets and liabilities		
Inventories	111.0	57.9
Receivables	70.1	(223.5)
Deferred seasonal rates	32.0	33.1
Payables	(13.1)	234.1
Energy marketing and risk management, net	(15.2)	(9.6)
Other	44.6	8.1
Net cash flow provided by operating activities	335.3	188.1
Cash flows from investing activities		
Property, plant and equipment expenditures	(45.3)	(36.2)
Purchase of Dynegy Inc.'s 20% ownership interest in SouthStar Energy Services LLC	-	(20.0)
Sale of ownership interest in US Propane LP	29.1	-
Cash received from equity investments	0.8	5.8
Other	(0.1)	5.2
Net cash flow used in investing activities	(15.5)	(45.2)
Cash flows from financing activities		
Payments and borrowings of short-term debt, net	(212.0)	(251.8)
Dividends paid on common shares	(19.0)	(16.5)
Payments of Medium-Term notes	(48.5)	-
Equity offering	-	136.7
Distribution to minority interest	(13.9)	-
Other	8.0	3.3
Net cash flow used in financing activities	(285.4)	(128.3)
Net increase in cash and cash equivalents	34.4	14.6
Cash and cash equivalents at beginning of period	16.5	8.4
Cash and cash equivalents at end of period	$50.9	$23.0
Cash paid during the period for		
Interest (net of allowance for funds used during construction)	$10.5	$13.6
Income taxes	$8.7	$0.3

See Notes to Condensed Consolidated Financial Statements (Unaudited).

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

Note 1
Accounting Policies and Methods of Application

General

AGL Resources Inc. is an energy services holding company that 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 condensed 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 that our disclosures are adequate and do not present misleading information. 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. The year-end condensed balance sheet data was derived from audited financial statements and should be read 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, 2003, filed with the SEC on February 6, 2004.

Due to the seasonal nature of our business, the results of operations for the three months ended March 31, 2004 are not necessarily indicative of the results of operations to be expected for any other interim period or for the year ending December 31, 2004. For a glossary of key terms and referenced accounting standards, see pages three and four of this filing.

Basis of Presentation

Our condensed consolidated financial statements as of and for the period ended March 31, 2004 include our accounts, the accounts of our majority-owned and controlled subsidiaries and the accounts of variable interest entities for which we are the primary beneficiary. All significant intercompany items have been eliminated in consolidation. Certain amounts from prior periods have been reclassified to conform to the current presentation. The December 31, 2003 balance sheet amounts are derived from the audited financial statements.

Our condensed consolidated financial statements include the accounts of SouthStar Energy Services LLC (SouthStar), a variable interest entity for which we are the primary beneficiary. Previously we accounted for our 70% non-controlling financial ownership interest in SouthStar using the equity method of accounting. We utilize the equity method to account for and report investments where we hold a 20% to 50% voting interest, and can exercise significant influence but not significant control over the entity. In 2003, under the equity method, our ownership interest in SouthStar was reported as an investment within our consolidated balance sheet, and our share of the investments’ earnings or losses was reported in our condensed consolidated statement of income as a component of other income.

In January 2003, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. (FIN) 46, “Consolidation of Variable Interest Entities” (FIN 46) and was effective for our December 31, 2003 consolidated financial statements. FIN 46 was subsequently revised in December 2003 (FIN 46R). FIN 46R clarifies the application of Accounting Research Bulletin No. 51, “Consolidated Financial Statements” to certain entities in which equity investors do not have the characteristics of a controlling financial interest. FIN 46R also defines a variable interest entity, and provides guidance for determining when a business enterprise should consolidate the results of a variable interest entity.

On March 31, 2004, we adopted FIN 46R resulting in the consolidation of SouthStar's accounts with our subsidiaries' accounts in our condensed consolidated financial statements; and the deconsolidation of the accounts related to our Trust Preferred Securities as of January 1, 2004. For more discussion on FIN 46R and the impact of its adoption on our condensed consolidated financial statements, see Note 2, Recent Accounting Pronouncements.

Stock-based Compensation

We have several stock-based employee compensation plans and we 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 SFAS No. 123, "Accounting for Stock-Based Compensation" (SFAS 123). For our stock option plans, we generally do not reflect stock-based employee compensation cost in net income, as options granted under 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 on the fair value of our common stock at the balance sheet date, since these awards constitute a variable plan under APB 25.

The following table illustrates the effect on our net income and earnings per share for the three months ended March 31, 2004 and 2003 as if we had applied the optional fair value recognition provisions of SFAS 123:

In millions, except per share amounts	2004	2003
Net income, as reported	$65.7	$51.8
Add: Total stock-based expense compensation expense recorded, net of related tax effect	-	0.1
Deduct: Total stock-based employee compensation expense determined under fair value-based method for all awards, net of related tax effect	(0.3)	(0.1)
Pro-forma net income	$65.4	$51.8
Earnings per share:		
Basic-as reported	$1.02	$0.86
Basic-Pro-forma	$1.01	$0.86
Diluted-as reported	$1.00	$0.85
Diluted-Pro-forma	$1.00	$0.85

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. At March 31, 2004, our comprehensive income included the unrealized gains of $0.3 million for hedging activities at SouthStar and $0.5 million of unrealized gains, net of tax, on our investment in marketable equity securities that we retained after the sale of US Propane LP. Approximately $1.8 million of other comprehensive income is expected to be reclassified into the condensed consolidated statements of income within the next 12 months as the underlying transactions settle. At March 31, 2003, total comprehensive income was equal to net income.

Earnings per Common Share

We compute basic earnings per common share by dividing our income available to common shareholders by the weighted-average number of common shares outstanding daily. Diluted earnings per common share reflect the potential 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 were no anti-dilutive items. The following table shows the calculation of our diluted shares for the three months ended March 31, 2004 and 2003, assuming performance units currently earned under the plan ultimately vest, and stock options currently exercisable at prices below the average market prices are exercised:

In millions	2004	2003
Denominator for basic earnings per share (daily weighted-average shares outstanding)	64.6	60.3
Assumed exercise of performance units and stock options	0.8	0.4
Denominator for diluted earnings per share	65.4	60.7

Note 2
Recent Accounting Pronouncements

FIN 46

FIN 46 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.

In December 2003, the FASB revised FIN 46, delaying the effective dates for certain entities created before February 1, 2003, and making other amendments to clarify application of the guidance. For potential variable interest entities other than any Special Purpose Entities, FIN 46R is now required to be applied no later than the end of the first fiscal year or interim reporting period ending after March 15, 2004.

FIN 46R 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 46R also requires certain disclosures of an entity's relationship with variable interest entities. We adopted FIN 46R as of March 31, 2004.

Notes payable to Trusts and Trust Preferred Securities In June 1997 and March 2001, we established AGL Capital Trust I and AGL Capital Trust II (Trusts) to issue our Trust Preferred Securities. The Trusts are considered to be special purpose entities under FIN 46 and FIN 46R since our equity in the Trusts is not considered to be sufficient to allow the Trusts to finance their own activities and our equity investment is not considered to be at risk since the equity amounts were financed by the Trusts.

Under FIN 46 (prior to the revision in FIN 46R), we concluded that we were the primary beneficiary of the Trusts because the Trust Preferred Securities are publicly traded, widely held, no one party would absorb a majority of any expected losses of the Trusts. In addition, our loan agreements with the Trusts include call options allowing us to capture the benefits of declining interest rates since the options enable us to call the preferred securities at par, giving us the ability to capture the majority of the residual returns in the Trusts. Accordingly, at December 31, 2003, the accounts of the Trusts were included in our consolidated financial statements.

The revisions in FIN 46R included specific guidance that instruments such as the call options included in our loan agreements with the Trusts do not constitute variable interests, and should not be considered in the determination of the primary beneficiary. As a result, we were required to exclude the accounts of the Trusts from our consolidated financial statements upon our adoption of FIN 46R and to classify amounts payable to the Trusts as "Notes Payable to Trusts" within capitalization in our condensed consolidated balance sheets as of March 31, 2004.

The impact of deconsolidation of the Trusts is that we have included in our condensed consolidated balance sheets at March 31, 2004, an asset of approximately $9.9 million representing our investment in the Trusts, and a note payable to the Trusts totaling approximately $232.0 million and removed $222.1 million related to the Trust Preferred Securities issued by the Trusts. The notes payable represent the loan payable to fund our investments in the Trusts of $9.9 million and the amounts due to the Trusts from the proceeds received from their issuances of Trust Preferred Securities of $222.1 million.

SouthStar As of December 31, 2003, we did not consolidate SouthStar in our financial statements because it did not meet the definition of a variable interest entity under FIN 46. FIN 46R added the following conditions for determining whether an entity was a variable interest entity:

- the voting rights of some investors are not proportional to their obligations to absorb the expected losses of the entity, their rights to receive the expected residual returns of the entity, or both, and
- substantially all of the entity's activities (for example purchasing products and additional capital) either involve or are conducted on behalf of an investor that has disproportionately fewer voting rights.

We determined that SouthStar is a variable interest entity because:

- our equal voting rights with Piedmont Natural Gas Company, Inc. (Piedmont) are not proportional to our economic obligation to absorb 75% of any losses or residual returns from SouthStar, and
- SouthStar obtains substantially all of its transportation capacity for delivery of natural gas through our wholly-owned subsidiary, Atlanta Gas Light Company (AGLC).

Consequently, as of March 31, 2004, we consolidated all of SouthStar's accounts with our subsidiaries' accounts and eliminated any intercompany balances between segments. We recorded Piedmont's portion of SouthStar's earnings as a minority interest in our condensed consolidated statements of income, and we recorded Piedmont's portion of SouthStar's capital as a minority interest on our condensed consolidated balance sheet.

SouthStar is a joint venture formed in 1998 by our subsidiary, Georgia Natural Gas Company, Piedmont and Dynegy Inc. (Dynegy) to market natural gas and related services to retail customers, principally in Georgia. Initially, we owned a 50% interest in SouthStar, Piedmont owned a 30% interest and Dynegy owned the remaining 20% interest.

On March 11, 2003, we purchased Dynegy's 20% ownership interest in a transaction that for accounting purposes had an effective date of February 18, 2003. Upon closing, we owned a noncontrolling 70% financial interest in SouthStar and Piedmont owned the remaining 30%. Our 70% interest is noncontrolling because all significant matters require approval by both owners. For all periods prior to February 18, 2003, SouthStar's earnings have been allocated to us based upon our ownership interests in those periods or 50%.

SouthStar, which operates under the trade name Georgia Natural Gas, competes with other energy marketers, including Marketers in Georgia, to provide natural gas and related services to customers in Georgia and the Southeast. Based upon its market share, SouthStar is the largest retail marketer of natural gas in Georgia with a 12 month average of approximately 550,000 customers. This represents a market share of approximately 36.9% as of March 31, 2004, which is relatively consistent with its market share of 38.0% in the prior year.

Note 3
Risk Management

Interest Rate Swaps

To maintain an effective capital structure, it is our policy to borrow funds using a mix of fixed-rate 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-rate and variable-rate debt obligations. On March 9, 2004, we terminated an interest rate swap on $100.0 million of the principal amount of our 4.45% Senior Notes Due 2013. Additionally, as of March 31, 2004 and in connection with the deconsolidation of the Trusts, we re-designated the interest rate swaps on the Trust Preferred Securities as a fair value hedge of our notes payable to the Trusts.

As of March 31, 2004, a notional principal amount of $175 million of these interest rate swap agreements effectively converted the interest expense associated with a portion of our Senior Notes and notes payable to the Trusts 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. Our interest rate swaps consist of the following:

- $100.0 million principal amount of 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 variable interest rate at March 31, 2004 was 4.6% an increase of 0.1% from December 31, 2003. These interest rate swaps expire January 14, 2011, unless terminated earlier.
- $75.0 million principal amount of 8.0% notes payable to Trusts 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 at March 31, 2004 was 2.4% a decrease of 0.1% from December 31, 2003. These interest rate swaps expire May 15, 2041, unless terminated earlier.

The aggregate fair value of these interest rate swaps was recorded as an asset of $5.5 million at March 31, 2004 and a liability of $3.7 million at December 31, 2003.

Commodity-related derivative instruments

Sequent Our commodity-related derivative financial instruments, which exclude the interest rate swaps discussed above, had a weighted average maturity of 6.3 months based on volumes. At March 31, 2004, our commodity-related derivative financial instruments represented purchases (long) of 487.0 billion cubic feet (Bcf) and sales (short) of 477.1 Bcf with approximately 96% of these scheduled to mature in less than 2 years and the remaining 4% in 3-9 years. For the three months ended March 31, 2004 and 2003, excluding the cumulative effect of a change in an accounting principle in 2003, our unrealized gains were $14.6 million in 2004 and $9.5 million in 2003.

SouthStar Natural gas derivative financial instruments are utilized by SouthStar to hedge natural gas inventory and to fix the price of a portion of natural gas purchases. These contracts settle monthly with varying maturity dates through September 2005. At March 31, 2004, the fair value of open positions was reflected in the condensed consolidated financial statements as an asset of $1.8 million with a corresponding increase to other comprehensive income of $1.8 million. For the three months ended March 31, 2004, a loss of $0.2 million was reclassified to earnings from other comprehensive income related to instruments designated as hedges under Statement of Financial Accounting Standards (SFAS) No. 133, “Accounting for Derivative Instruments and Hedging Activities” (SFAS 133) and a loss of $0.6 million was recognized on instruments not designated as hedges under SFAS 133 representing the change in fair value of those instruments during the period. No amounts were recorded to earnings related to hedge ineffectiveness.

Concentration of Credit Risk

Sequent Energy Management, L.P. (Sequent), which provides services to marketers and to utility and industrial customers, has a concentration of credit risk measured by 30-day receivable exposure plus forward exposure, which is highly concentrated in 20 of its customers. At March 31, 2004, Sequent's top 20 counterparties represented approximately 67% of the total counterparty exposure of $159.5 million, derived by adding the top 20 counterparties' exposures and dividing by the total of Sequent's counterparties' exposures.

During 2004, Sequent refined its calculation used to determine the Standard & Poor's (S&P) equivalent credit rating for counterparties in order to reflect various sub-categories of ratings. The S&P equivalent credit rating is determined by a process of converting the lower of the S&P or Moody's Investors Service, Inc. (Moody's) rating to an internal rating ranging from 9.00 to 1.00, with 9.00 being equivalent to AAA/Aaa by S&P and Moody's and 1.00 being D or Default by S&P and Moody's. A counterparty that does not have an external rating is assigned an internal rating based on the strength of the financial ratios of the counterparty.

The weighted average credit rating is obtained by multiplying each counterparty's assigned internal rating by the counterparty's credit exposure and summed for all counterparties. That total is divided by the aggregate total counterparties' exposure. This numeric value is converted to an S&P equivalent. Under the refined methodology, Sequent's counterparties, or the counterparties' guarantors, had a weighted average S&P equivalent credit rating of BBB+ at March 31, 2004 and December 31, 2003, compared with our previously reported rating of BBB at December 31, 2003 under our prior methodology.

Note 4
Regulatory Assets and Liabilities

We have recorded regulatory assets and liabilities in our 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 (PRP) costs and unrecovered environmental response costs (ERC), are summarized in the table below:

In millions	March 31, 2004	Dec. 31, 2003	Variance
Regulatory assets			
Unrecovered PRP costs	$425.5	$431.8	($6.3)
Unrecovered ERC	180.0	179.4	0.6
Unrecovered postretirement benefit costs	9.3	9.4	(0.1)
Unrecovered seasonal rates (1)	-	10.8	(10.8)
Unamortized call premium (2)	6.0	4.2	1.8
Regulatory tax asset (2)	3.0	3.1	(0.1)
Other (3)	0.3	0.6	(0.3)
Total	$624.1	$639.3	($15.2)
Regulatory liabilities			
Accumulated removal costs	$103.5	$102.4	$1.1
Deferred seasonal rates (4)	21.2	-	21.2
Unamortized investment tax credit (5)	18.6	18.9	(0.3)
Deferred PGA (4)	43.0	29.7	13.3
Regulatory tax liability (5)	14.6	14.9	(0.3)
Other (3)	2.5	2.8	(0.3)
Total regulatory liabilities	203.4	168.7	34.7
Associated liabilities			
PRP costs	397.1	404.3	(7.2)
ERC	79.8	83.0	(3.2)
Total associated liabilities	476.9	487.3	(10.4)
Total regulatory and associated liabilities	$680.3	$656.0	$24.3

(1) Presented in other current assets in our condensed consolidated balance sheets.
(2) Presented in other deferred debits and other assets in our condensed consolidated balance sheets.
(3) Presented in other deferred debits and other assets, other current liabilities and accrued postretirement benefit costs in our condensed consolidated balance sheets.
(4) Presented in other current liabilities in our condensed consolidated balance sheets.
(5) Presented in deferred credits in our condensed consolidated balance sheets.

Environmental Response Costs

Our last engineering estimate of the costs to remediate certain former manufactured gas plant sites was as of December 31, 2003. This latest estimate projected costs associated with AGLC's engineering estimates and in-place contracts to be $62.5 million, a reduction of $3.9 million from the estimate as of September 30, 2003. For those remaining elements of the MGP program where AGLC is unable to perform engineering cost estimates at the current state of investigation, considerable variability remains in the estimates for future remediation costs. For these elements, the estimate for the remaining cost of future actions at MGP sites is $15.2 million. AGLC estimates certain other costs related to administering the MGP program and remediation of sites currently in the investigation phase. Through January 2005, AGLC estimates the administrative costs to be $2.7 million. Beyond January 2005, these costs are not estimable.

For those sites currently in the investigation phase, our estimate is $9.4 million. This estimate is based upon preliminary data received during 2003 with respect to the existence of contamination of those sites. Our range of estimates for these sites is from $9.4 million to $15.1 million. We have accrued the low end of our range, or $9.4 million, as this is our best estimate at this phase of the remediation process. AGLC's ERC liability is composed of the elements in the following table:

In millions	March 31, 2004	Dec. 31, 2003	2004 vs. 2003
Projected engineering estimates and in-place contracts (1)	$62.5	$66.4	($3.9)
Estimated future remediation costs (1)	15.2	15.3	(0.1)
Administrative expenses	2.7	2.7	-
Other expenses	9.4	9.4	-
Cash payments for cleanup expenditures (2)	(10.0)	(10.8)	0.8
Accrued ERC	$79.8	$83.0	($3.2)

(1) As of December 31, 2003 and September 30, 2003.
(2) Expenditures during the three months ended March 31, 2004 and December 31, 2003.

The ERC liability is included in a corresponding regulatory asset. As of March 31, 2004, the regulatory asset was $180.0 million, which is a combination of accrued ERC 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.

AGLC has three ways of recovering investigation and cleanup costs. The GPSC has approved an ERC recovery rider. It allows recovery of the costs of investigation, testing, cleanup and litigation. Because of this 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. AGLC recovered $6.0 million during the three months ended March 31, 2004, through its ERC 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 three months ended March 31, 2004. The remaining way AGLC can recover costs is from the receipt of net profits from the sale of remediated property.

2004 is expected to be the last significant year of spending for this program. The ERC recovery mechanism allows for recovery of expenditures over a five-year period subsequent to the period in which the expenditures are incurred. As of March 31, 2004, the MGP expenditures expected to be incurred over the next 12 months are reflected as a current liability of $50.8 million. In addition, AGLC expects to collect $25.1 million in revenues over the next 12 months under the ERC recovery rider, which is reflected as a current asset.

Note 5
Pension and Other Postretirement Benefits

Accounting for Pension Benefits

The measurement date for our pension and other postretirement benefit plans are as of December 31. The following are the costs components of our pension and other postretirement benefit plans for the three months ended March 31, 2004 and 2003.

	Pension Benefits		**Other Benefits**	
In millions	**2004**	**2003**	**2004**	**2003**
Service cost	$1.2	$1.1	$0.4	$0.3
Interest cost	4.7	4.8	2.0	2.1
Expected return on plan assets	(5.9)	(5.6)	(0.8)	(0.7)
Net amortization	(0.2)	(0.2)	(0.1)	0.3
Recognized actuarial loss	0.9	0.4	0.5	-
Net annual cost	$0.7	$0.5	$2.0	$2.0

Employer Contributions

As of December 31, 2003, we expected to contribute approximately $15.0 million to our pension plan in 2004. However, we worked with our actuaries to compute the minimum required pension contribution, and consequently made a $12.5 million contribution in April of 2004. We do not expect to make any further contributions in 2004 to our pension plan.

Note 6
Financing

Dollars in millions	Year(s) Due	March 31, 2004 Int. rate (5)	March 31, 2004 Outstanding	December 31, 2003 Int. rate (5)	December 31, 2003 Outstanding
Short-term debt					
Commercial paper (1)	2004	1.2%	$91.0	1.2%	$303.5
Current portion of long-term debt	2004	7.6 – 7.75	33.5	7.0 – 7.75	77.0
Sequent line of credit (2)	2004	1.6	6.5	1.4	2.9
SouthStar non-recourse debt (3)	2004	4.0	2.1	-	-
Total short-term debt (4)		**2.8%**	**$133.1**	**2.4%**	**$383.4**
Long-term debt - net of current portion					
Medium-Term notes					
Series A	2021	9.10%	$30.0	9.10%	$30.0
Series B	2012-2022	8.3 – 8.7	61.0	8.3 – 8.7	61.0
Series C	2014-2027	6.55 – 7.3	116.7	6.55 – 7.3	121.7
Senior Notes	2011-2013	4.45 - 7.125	525.0	4.45 - 7.125	525.0
AGL Capital interest rate swaps	2011-2013	4.57	0.6	1.80 – 4.52	(6.9)
Total Medium-Term and Senior notes			$733.3		$730.8
Notes payable to Trusts	2037-2041	8.0 – 8.17%	$232.0	-	-
Trust Preferred Securities					
AGL Capital Trust I	2037	-	-	8.17%	$74.3
AGL Capital Trust II	2041	-	-	8.0	147.8
AGL Capital interest rate swaps	2041	2.44	4.9	2.45	3.2
Total Notes payable to Trusts			236.9		-
Total Trust Preferred Securities			-		225.3
Total long-term debt (4)		**6.2%**	**$970.2**	**5.9%**	**$956.1**
Total short-term and long-term debt (4)		**5.8%**	**$1,103.3**	**4.9%**	**$1,339.5**

(1) The daily weighted average rate was 1.2% for the quarter ended March 31, 2004 and 1.3% for 2003.
(2) The daily weighted average rate was 1.5% for the quarter ended March 31, 2004 and 1.6% for 2003.
(3) The daily weighted average rate was 4.0% for the quarter ended March 31, 2004.
(4) Weighted average interest rate, including interest rate swaps if applicable.
(5) Interest rates exclude debt issuance and other financing related costs.

Short-term Debt

Our short-term debt is composed of borrowings under our commercial paper program which consists of short-term unsecured promissory notes with maturities ranging from 15 to 91 days, maturities within one year of our Medium-Term notes, Sequent's line of credit and SouthStar's non-recourse debt. The commercial paper program is supported by our Credit Facility, which consists of a $200.0 million 364-day Credit Facility with a one-year term-out option that terminates on June 16, 2004, and a $300.0 million three-year Credit Facility that terminates on August 7, 2005.

Note 7
Commitments and Contingencies

The following table illustrates our expected future contractual cash obligations as of March 31, 2004:

		Payments Due before December 31,			
In millions	Total	2004	2005 & 2006	2007 & 2008	2009 & Thereafter
Long-term debt (1)	$970.2	-	-	-	970.2
Pipeline charges, storage capacity and gas supply (2)	741.4	209.3	243.5	105.6	183.0
Pipeline replacement program costs (3)	397.1	73.1	162.0	162.0	-
Short-term debt	133.1	133.1	-	-	-
ERC (3)	79.8	32.9	31.4	5.6	9.9
Operating leases (4)	71.6	9.4	18.9	14.5	28.8
Communication/network service and maintenance	18.3	7.3	11.0	-	-
Total	$2,411.5	$465.1	$466.8	$287.7	$1,191.9

(1) Includes $232.0 million of Notes payable to Trusts, callable in 2006 and 2007.

(2) Charges recoverable through a PGA mechanism or alternatively billed to Marketers.

(3) Charges recoverable through rate rider mechanisms.

(4) 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 No. 13, "Accounting for Leases." However, this accounting treatment does not affect the future annual operating lease cash obligations as shown herein.

FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (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 expected commercial commitments that are outstanding as of March 31, 2004 and meet the disclosure criteria required by FIN 45:

		Commitments Due before December 31,			
In millions	Total	2004	2005 & 2006	2007 & 2008	2009 & Thereafter
Guarantees (1) (2)	$213.5	$213.5	$-	$-	$-
Standby letters of credit, performance/ surety bonds	10.0	10.0	-	-	-
Total other commercial commitments	$223.5	$223.5	$-	$-	$-

(1) $164.2 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.

(2) We provide guarantees on behalf of our subsidiary, 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 $42.3 million, which represents our share of SouthStar's maximum credit support obligation to AGLC under its tariff.

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. Change to the status of previously disclosed litigation is as follows:

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 included fraud and deceit and damages to realty. The allegations arose from negotiations between the city and AGLC regarding the environmental cleanup obligations connected with AGLC's former MGP operations in Augusta. This litigation was settled and the lawsuit dismissed.

Note 8
Segment Information

Our business is organized into three operating segments:

- Distribution operations consists of AGLC, Virginia Natural Gas (VNG) and Chattanooga Gas Company (CGC).
- Wholesale services consists primarily of Sequent.
- Energy investments consists primarily of SouthStar, AGL Networks, LLC and US Propane LP through the date of its sale in January 2004.

We treat corporate, our fourth segment, as a non-operating business segment, and it includes AGL Resources Inc., AGL Services Company, Pivotal Energy Development, nonregulated financing and the effect of intercompany eliminations. We eliminated intersegment sales for the three months ended March 31, 2004 and 2003 from our statements of consolidated income.

We evaluate 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 a 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 business from an operational perspective, exclusive of the costs to finance those activities and exclusive of income taxes, neither of which is directly relevant to the efficiency of those operations.

EBIT should not be considered an alternative to, or a more meaningful 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, earnings before income taxes and net income for the three months ended March 31, 2004 and 2003 are presented below.

In millions	**2004**	**2003**
Operating income	$133.2	$101.5
Other income	0.5	16.1
Minority interest	(11.0)	-
EBIT	122.7	117.6
Interest expense	(15.9)	(19.9)
Earnings before income taxes	106.8	97.7
Income taxes	(41.1)	(38.1)
Income before cumulative effect of change in accounting principle	65.7	59.6
Cumulative effect of change in accounting principle	-	(7.8)
Net income	$65.7	$51.8

	As of or for the 3 months ended March 31, 2004				
In millions	Distribution Operations	Wholesale Services	Energy Investments	Corporate and Intersegment Eliminations	Consolidated AGL Resources
Operating revenues (1)	$388.9	$20.4	$308.5	($66.8)	$651.0
Depreciation and amortization	21.0	0.1	0.5	2.6	24.2
Operating income (loss)	82.0	12.3	42.4	(3.5)	133.2
Earnings in equity interests	-	-	0.7	-	0.7
Other income (loss)	0.1	-	0.1	(0.4)	(0.2)
Minority interest	-	-	(11.0)	-	(11.0)
EBIT	82.1	12.3	32.2	(3.9)	122.7
Identifiable assets	3,284.1	453.3	282.2	(95.6)	3,924.0
Investment in joint ventures	-	-	1.8	-	1.8
Total assets	3,284.1	453.3	284.0	(95.6)	3,925.8
Capital expenditures	36.4	2.6	5.5	0.8	45.3

	For the 3 months ended March 31, 2003				
In millions	Distribution Operations	Wholesale Services	Energy Investments	Corporate and Intersegment Eliminations	Consolidated AGL Resources
Operating revenues (1)	$320.7	$28.5	$3.3	$-	$352.5
Depreciation and amortization	20.2	-	0.1	2.0	22.3
Operating income (loss)	80.7	20.7	(0.1)	0.2	101.5
Equity in earnings of SouthStar	-	-	14.4	-	14.4
Earnings in equity interests	-	-	1.5	-	1.5
Interest income	-	-	0.1	-	0.1
Other income (loss)	0.3	-	0.1	(0.3)	0.1
EBIT	81.0	20.7	16.0	(0.1)	117.6
Capital expenditures	26.0	0.1	3.8	6.3	36.2

	As of December 31, 2003				
	Distribution Operations	Wholesale Services	Energy Investments	Corporate and Intersegment Eliminations	Consolidated AGL Resources
Identifiable assets	$3,325.0	$460.0	$89.6	$1.9	$3,876.5
Investment in joint ventures	-	-	101.3	-	101.3
Total assets	$3,325.0	$460.0	$190.9	$1.9	$3,977.8

(1) Intersegment revenues – Wholesale services records its energy marketing and risk management revenue on a net basis. The following table provides detail of wholesale services' total gross revenues and gross sales to distribution operations:

In millions	Third-Party Gross Revenues	Intersegment Revenues	Total Gross Revenues
1st Quarter 2004	$1,024.1	$95.6	$1,119.7
1st Quarter 2003	1,054.3	113.0	1,167.3

ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operation

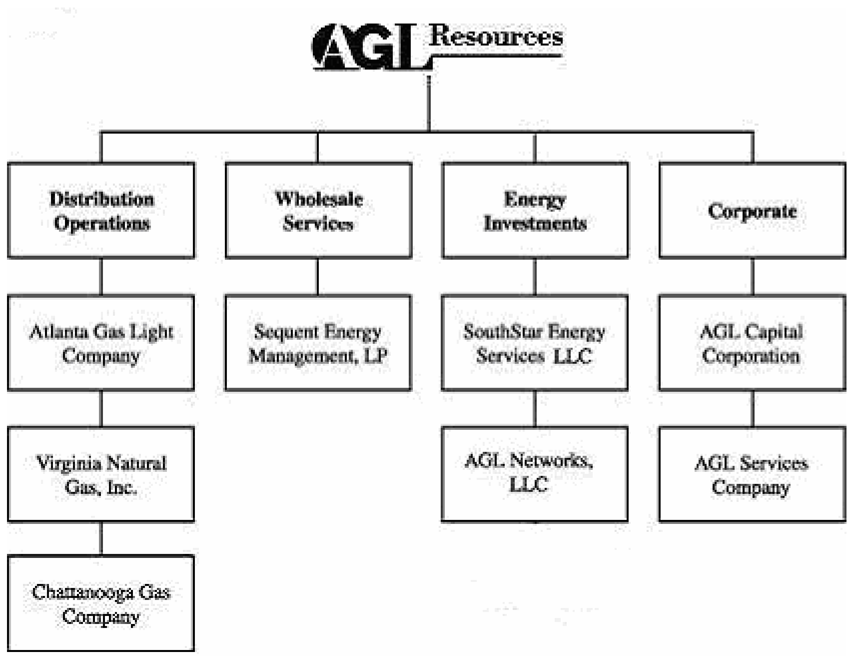
CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

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). 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, including those set forth below and in our Form 10-K filed with the Securities and Exchange Commission on February 6, 2004 under Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" under the caption "Risk Factors." The following are among the important factors that could cause actual results to differ materially from the results discussed in 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 Atlanta Gas Light Company's (AGLC's) performance-based rate plan (PBR)
- the ultimate impact of the Sarbanes-Oxley Act of 2003 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 Securities and Exchange Commission (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 and 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 – that is, marketers who are certificated by the Georgia Public Service Commission (GPSC) to sell retail natural gas in Georgia – 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, LLC's 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

Executive Summary

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. Our principal executive offices are located at Ten Peachtree Place NE, Atlanta, Georgia 30309. The telephone number at that address is (404) 584-4000. As shown in the following chart, we conduct substantially all our operations through our subsidiaries, which we manage as three operating segments--distribution operations, wholesale services and energy investments--and one nonoperating segment, corporate, which includes intercompany eliminations.



Distribution operations include our three utilities that construct, manage and maintain gas pipeline in Georgia, Tennessee and Virginia and serves more than 1.8 million end-use customers. Approximately 83% are located in Georgia, 14% are located in Virginia and 3% are located in Tennessee. Our wholesale services segment includes our nonutility business engaged in natural gas asset management and optimization, producer services and wholesale marketing, and risk management activities. Our energy investments segment includes our nonutility businesses engaged in retail natural gas marketing and operating telecommunications conduit and fiber infrastructure within select metropolitan areas.

Our overall business strategy is to operate and grow our gas distribution operations efficiently and effectively, optimize returns on our assets, and selectively grow our portfolio of closely related businesses while remaining focused on risk management and earnings visibility. The following section is a brief overview that provides context for our Management's Discussion and Analysis.

Industry dynamics Since the winter of 2000-2001, the price of natural gas has become increasingly volatile. This increased volatility is primarily a result of production of natural gas that has failed to keep pace with demand for natural gas supplies in the United States. The vast majority of North America's gas supply comes from mature producing areas, such as the Gulf of Mexico and western Canada. New sources of supply will need to be identified in the future to meet demand. Many new sources currently being explored are related to federally protected lands throughout the United States, where significant supply exists but natural gas drilling is restricted or prohibited. The prolonged absence of a national energy policy governing access to these areas creates risk that these supply sources will remain untapped.

Increasingly, imported liquefied natural gas (LNG) is becoming a supplemental supply source, and currently comprises only about 2 percent of the total United States natural gas supply. New LNG processing facilities will be required to increase the capacity of the United States to import LNG. Large-scale LNG facilities are capital-intensive projects with a multi-year construction-to-market cycle. While many companies are making significant investments in these facilities and in developing potential new facilities, it is difficult to predict with any certainty what impact this additional supply will have on overall future market dynamics. Given the current levels of demand and the current constraints on supply, industry experts are generally predicting that natural gas prices will remain elevated relative to historical norms for the next several years.

Our distribution operations businesses and SouthStar Energy Services, LLC (SouthStar) face competition based upon our customers' preferences for natural gas compared to other energy products and the comparative prices of those products. The increase in the wholesale natural gas prices has resulted in increases in the costs of natural gas billed to customers, and has affected, to some extent, our ability to retain customers, which remains one of our larger challenges in 2004. We lose customers to propane and electricity and are particularly susceptible to the loss of rural customers and heat-only customers. We are generally at risk of losing customers when a customer disconnects for seasonal purposes or when a customer replaces an appliance.

Our principal competition relates to the electric utilities serving the residential and small commercial markets throughout our service areas and the potential displacement or replacement of natural gas appliances with electric appliances. The primary competitive factors are the price of energy and the comfort of natural gas heating versus electric heating and other energy sources. Our customers' demand for natural gas and the level of business of our natural gas assets could be affected by numerous factors, including:

- changes in the availability or price of natural gas and other forms of energy
- general economic conditions
- energy conservation
- legislation and regulations
- the capability to convert from natural gas to alternative fuels and
- weather

While volatility in natural gas prices has been a general trend since 2001, there often is a significant difference in natural gas prices at various regional United States trading hubs. Our subsidiary, Sequent Energy Management (Sequent), uses market volatility and regional price differentials to provide its customers with the most economic natural gas services possible. In doing so, Sequent may purchase natural gas in one market for immediate resale in another market in order to capture positive differences in prices and physical deliveries of natural gas between regional price points or over various time horizons.

In addition, Sequent competes for asset management business with other energy wholesalers, often through a competitive bidding process. Sequent has historically been successful in obtaining new asset management business by placing bids that were based primarily on the intrinsic value of the transaction, which is the difference in commodity prices between time periods or locations at the inception of the transaction.

In recent months, energy wholesalers have become increasingly willing to place bids for asset management deals that are priced to include extrinsic value, or additional value for the margins the wholesaler may be able to capture over the term of the asset management deal (also known as time value). We expect this trend to continue in the near term, and the increasing competition for asset management deals could result in downward pressure on the volume of transactions, and the related margins available in this portion of Sequent's business.

Revenues and Cash flow We generate nearly all of our operating revenues and cash flow through the sale, distribution and storage of natural gas. Distribution operations' revenues contributed 59.7% of our consolidated revenues for the three months ended March 31, 2004 and 90.9% for the same period in 2003. The decrease of 31.2% in 2004 reflects the consolidation of SouthStar with our subsidiaries in 2004. An estimate of the amount of natural gas distributed, but not yet billed, to residential and commercial customers from the latest meter reading date to the end of the reporting period is also recognized in revenues and recorded as unbilled revenues on our condensed consolidated balance sheet.

A significant portion of our operations is subject to seasonal fluctuations. During the heating season, which is primarily from November through March, net revenues are more significant since generally more customers will be connected in periods of colder weather than in periods of warmer weather.

Revenue and cash flow for our non-utility businesses is subject to variability associated with changes in commodity prices. Our non-utility businesses use physical and financial arrangements to hedge this price risk. Certain hedging and trading activities may require cash deposits to satisfy margin requirements. In addition, reported earnings for the wholesale services and energy investment segments reflect changes in the fair value of certain derivatives; these values may change significantly from period to period.

Other activities On January 20, 2004, we completed the divesture of our general and limited partnership interests in US Propane LP. We received $29 million for the sale of our interests and did not recognize a material gain on the transaction.

On March 29, 2004, we executed an amended and restated partnership agreement with Piedmont Natural Gas Company, Inc. (Piedmont). This new agreement calls for SouthStar's future earnings starting in 2004 to be allocated 75% to our subsidiary and 25% to Piedmont. In addition, we agreed on a management services agreement, which provides that AGL Services Company will provide and administer accounting, treasury, internal audit, human resources and information technology functions on behalf of SouthStar.

As a result of the adoption of FIN 46R, we consolidated all of SouthStar's accounts with our subsidiaries' accounts as of March 31, 2004. We recorded Piedmont's portion of SouthStar's earnings as a minority interest in our condensed consolidated statements of income and recorded Piedmont's portion of SouthStar's capital as minority interest in our condensed consolidated balance sheet. We eliminated any intercompany balances between segments. Management's discussion and analysis includes pro-forma results as if SouthStar's accounts were consolidated with our subsidiaries' accounts for the three months ended March 31, 2003. These pro-forma results provide comparability between the presented periods and are presented for informational purposes and are not necessarily indicative of future operations.

Operating margin and EBIT Our operating margin is a measure of income, calculated as revenues minus cost of gas and cost of sales, excluding operation and maintenance expense, depreciation and amortization and taxes other than income taxes. These items are included in our calculation of operating income. We believe operating margin is a better indicator than revenues of the top line contribution resulting from customer growth, since cost of gas is generally passed directly to our customers.

We evaluate our segments' financial performance based on the measure of earnings before interest and taxes (EBIT), a non-GAAP measure that includes operating income, other income, equity in SouthStar's income in 2003, donations, minority interest in 2004 and gain on sales of assets. 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 principles, each of which are evaluated 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 is directly relevant to the efficiency of those operations. Our operating margin and EBIT are not calculated with accounting principles generally accepted in the United States of America (GAAP).

The following are reconciliations of our operating margin and EBIT to operating income and net income for the three months ended March 31, 2004 and 2003 and on a pro-forma basis to adjust the three months ended March 31, 2003 to reflect the consolidation of SouthStar's accounts.

In millions	**2004** (1)	**2003**	**Pro-forma 2003** (1)	**2004 vs. 2003**	**2004 vs. Pro-forma 2003**
Operating revenues	$651.0	$352.5	$596.7	$298.5	$54.3
Cost of gas	392.8	148.6	347.3	244.2	45.5
Operating margin	258.2	203.9	249.4	54.3	8.8
Operating expenses					
Operation and maintenance	92.9	72.2	90.5	20.7	2.4
Depreciation and amortization	24.2	22.3	22.7	1.9	1.5
Taxes other than income taxes	7.9	7.9	7.9	-	-
Total operating expenses	125.0	102.4	121.1	22.6	3.9
Operating income	133.2	101.5	128.3	31.7	4.9
Other income	0.5	16.1	1.8	(15.6)	(1.3)
Minority interest (2)	(11.0)	-	(12.5)	(11.0)	1.5
EBIT	$122.7	$117.6	$117.6	$5.1	$5.1

(1) Includes 100% of SouthStar's revenues and expenses.
(2) Minority interest adjusts our earnings to reflect our 75% share of SouthStar's earnings in 2004 and our 70% share in 2003 (less Dynegy Inc.'s 20% share of SouthStar's income prior to February 18, 2003).

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

In millions, except per share amounts	**2004**	**2003**	**2004 vs. 2003**
EBIT by segment			
Distribution operations	$82.1	$81.0	$1.1
Wholesale services	12.3	20.7	(8.4)
Energy investments	32.2	16.0	16.2
Corporate	(3.9)	(0.1)	(3.8)
Consolidated EBIT	122.7	117.6	5.1
Interest expense	(15.9)	(19.9)	4.0
Earnings before income taxes	106.8	97.7	9.1
Income taxes	(41.1)	(38.1)	(3.0)
Income before cumulative effect of change in accounting principle	65.7	59.6	6.1
Cumulative effect of change in accounting principle	-	(7.8)	7.8
Net income	$65.7	$51.8	$13.9
Basic earnings per common share			
Income before cumulative effect of change in accounting principle	$1.02	$0.99	$0.03
Cumulative effect of change in accounting principle	-	(0.13)	0.13
Basic earnings per common share	$1.02	$0.86	$0.16
Diluted earnings per common share			
Income before cumulative effect of change in accounting principle	$1.00	$0.98	$0.02
Cumulative effect of change in accounting principle	-	(0.13)	0.13
Diluted earnings per common share	$1.00	$0.85	$0.15
Weighted average number of common shares outstanding			
Basic	64.6	60.3	4.3
Diluted	65.4	60.7	4.7

Interest expense The decrease in interest expense of $4.0 million for 2004 as compared to 2003 was a result of lower interest rates on commercial paper borrowings, lower average debt balances, the repayment of Medium-Term notes in 2003 and interest rate swap transactions. As shown in the following table, our average debt balances were lower as compared to last year, due to the proceeds generated from the equity offering, which occurred on February 14, 2003, and lower working capital needs.

Dollars in millions	**2004**	**2003**	**2004 vs. 2003**
Total interest expense	$15.9	$19.9	$4.0
Average debt outstanding (1)	$1,213.6	$1,296.4	($82.8)
Average rate	5.2%	6.1%	(0.9%)

(1) Daily average of all outstanding debt including our note payable to Trusts in 2004 and Trust Preferred Securities in 2003.

Income taxes The increase in income tax expense of $3.0 million for 2004 as compared to 2003 was primarily due to the increase in earnings before income taxes of $9.1 million, offset by a decrease in the effective tax rate. The decrease in the effective tax rate was primarily due to a decrease in state taxes, which was partially offset by additional tax expense due to recognition of a tax gain from our sale of our general and limited partnership interest in US Propane.

Dollars in millions	**2004**	**2003**	**2004 vs. 2003**
Earnings before income taxes	$106.8	$97.7	$9.1
Income tax expense	41.1	38.1	3.0
Effective tax rate	38.5%	39.0%	(0.5%)

Results of Operations

Distribution Operations

Distribution operations include the results of operations and financial condition of our three natural gas local distribution utility companies: Atlanta Gas Light Company (AGLC), Virginia Natural Gas (VNG) and Chattanooga Gas Company (CGC). Each utility operates subject to regulations provided by the state regulatory agencies in its service territories. The Georgia Public Service Commission (GPSC) regulates AGLC; the Virginia State Corporation Commission (VSCC) regulates VNG; and the Tennessee Regulatory Authority (TRA) regulates CGC with respect to rates charged to our customers, maintenance of accounting records and various other service and safety matters.

Rates charged to our customers vary according to customer class (residential, commercial or industrial) and rate jurisdiction. Rates are set at levels that allow for the recovery of all prudently incurred costs, including a return on rate base sufficient to pay interest on debt and provide a reasonable return on common equity. Rate base consists generally of the original cost of utility plant in service, working capital, inventories and certain other assets; less accumulated depreciation on utility plant in service, net deferred income tax liabilities and certain other deductions. We continuously monitor the performance of our utilities to determine whether rates need to be adjusted by making a rate case filing.

- **AGLC** is a natural gas local distribution utility with distribution systems and related facilities throughout Georgia. AGLC has approximately 6 Bcf of LNG storage capacity in three LNG plants to supplement the supply of natural gas during peak usage periods. Pursuant to the Georgia Natural Gas Competition and Deregulation Act, AGLC is designated as an "electing distribution company," which means that AGLC is required to offer LNG peaking services to Marketers—that is, marketers who are certificated by the GPSC to sell retail natural gas in Georgia--at rates and on terms approved by the GPSC.

  AGLC has executed an agreement, subject to board approval, with Southern Natural Gas (SNG), a subsidiary of El Paso Corporation, to acquire a portion of SNG's interstate pipeline that runs from Macon to Atlanta. The transaction is valued at approximately $32 million. As part of the agreement, AGLC will extend the existing SNG transportation contracts to ensure reliable delivery of natural gas into Georgia in return for the right to expand AGLC's system off of the purchased facilities. We expect the SNG transaction to close by April 30, 2005, subject to clearing regulatory approvals.

- **VNG** is a natural gas local distribution utility with distribution systems and related facilities serving the 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.

  In 2004, Pivotal Propane of Virginia, Inc., (Pivotal Propane) our wholly-owned subsidiary intends to complete the construction of a propane air facility in the VNG service area to provide VNG with 28,800 dekatherms of propane air per day on a 10-day-per-year basis to serve its peaking needs. VNG has received approval from the VSCC to build the $30 million propane air plant to improve the reliability of their system in Virginia. However, we are awaiting the VSCC's final decision on the regulatory recovery mechanism for this project. The VSCC held hearings in late April and we expect a final decision in the near future.

- **CGC** is a natural gas local distribution utility with distribution systems and related facilities serving the Chattanooga and Cleveland areas of Tennessee. CGC has approximately 1.2 Bcf of LNG storage capacity in its LNG plant. In the first quarter of 2004, the TRA allowed CGC to alter its rates to recover more of its uncollectible accounts. As the commodity cost of natural gas has increased in recent years, CGC and other regulated distribution companies have incurred an increase in uncollectible accounts that was not anticipated when base rates were last established.

  On March 17, 2003 CGC filed a joint petition with other distribution companies requesting the TRA issue a declaratory ruling that the portion of CGC's uncollectible accounts directly related to cost of the natural gas is recoverable through a Purchased Gas Adjustment (PGA) mechanism. The PGA mechanism allows the local distribution companies to automatically adjust their rates to reflect changes in the wholesale cost of natural gas and to insure the utilities recover 100% of the cost incurred in purchasing gas for their customers. On February 9, 2004 the TRA ruled that the gas portion of accounts written-off as uncollectible after March 10, 2004 could be recovered through the PGA.

Results of Operations for the three months ended March 31, 2004 and 2003 are as follows:

In millions	**2004**	**2003** (1)	**2004 vs. 2003**
Operating revenues	$388.9	$320.7	$68.2
Cost of gas	209.0	148.0	61.0
Operating margin	179.9	172.7	7.2
Operating expenses			
Operation and maintenance	70.6	65.3	5.3
Depreciation and amortization	21.0	20.2	0.8
Taxes other than income	6.3	6.5	(0.2)
Total operating expenses	97.9	92.0	5.9
Operating income	82.0	80.7	1.3
Other income	0.1	0.3	(0.2)
EBIT	$82.1	$81.0	$1.1

Metrics			
Average end-use customers (in thousands)	1,840	1,829	0.6%
Operation and maintenance expenses per customer	$38	$36	5.6%
EBIT per customer	$45	$43	2.3%
Customers per employee	1,003	973	3.1%
Throughput (in millions of dekatherms)			
Firm	90.1	90.1	-%
Interruptible	27.9	27.6	1.1%
Total	118.0	117.7	0.3%
			Colder / (Warmer)
Heating degree days (2):			
Georgia (10 yr avg. 1,405)	1,503	1,553	(3.2%)
Virginia (10 yr avg. 1,787)	1,853	1,962	(5.5%)
Tennessee (10 yr avg. 1,737)	1,716	1,825	(6.0%)

(1) We reclassified regulatory carrying charges of $1.1 million from other income to operating revenues.
(2) 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 Fahrenheit. 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.

2004 compared to 2003

The increase in EBIT of $1.1 million was the result of increased operating margin of $7.2 million primarily driven by net customer growth, partially offset by increases in operating expenses of $5.9 million. Our three utilities added nearly 11,000 in net average connected customers in first quarter 2004 as compared to 2003. Weather in our service areas was 5% warmer, on average than during the first quarter 2003.

Operating margin increased $7.2 million primarily due to the following:

- AGLC's operating margin increased $4.6 million resulting from an increase of $1.9 million primarily due to net customer growth, an increase of $1.8 million due to additional carrying charges for gas stored for marketers, and an increase of $0.9 million from increased pipeline replacement program (PRP) revenue.
- VNG's and CGC's operating margin increased $2.6 million due primarily to increased customers and usage.

Total operating expenses for the quarter were $97.9 million, up from $92.0 million in the same period last year. The increase of $5.9 million was primarily a result of:

- $3.8 million increase in operations and maintenance expense as a result of increased information services and technology costs due to software licensing agreements and a loss on the retirement of information services and technology hardware, increased marketing expense for a gas appliance rebate program and increased fuel costs for our fleet vehicles
- $1.0 million additional pension expense as a result of lower return on assets
- $0.8 million increase in depreciation expenses primarily from new rates at VNG and increased assets at each utility

Wholesale Services

Wholesale services includes the results of operations and financial condition of Sequent, our subsidiary involved in asset optimization, producer services, wholesale marketing and risk management. 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.

Regulatory agreements We have reached the following agreements with state regulatory commissions to clarify Sequent's role as asset manager for our regulated utilities. Failure to renew these agreements would have a significant impact on Sequent's EBIT.

- 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). A December 2002 GPSC order requires net margin earned by Sequent, for transactions involving AGLC assets other than capacity release, to be shared equally with the USF. In February 2004, we contributed $0.5 million to the USF based upon profits earned during the last six months of 2003.
- In November 2000, the VSCC approved an asset management agreement that provides for a sharing of profits between Sequent and VNG's customers. This agreement expires in October 2005, unless Sequent, VNG and the VSCC agree to extend the contract. In December 2003, we contributed $4.7 million to VNG's customers for the contract year November 2002 through October 2003. This contribution will be reflected as a reduction to customer gas cost in 2004. We will contribute profits earned in the contract year November 2003 through October 2004 in December 2004.
- In June 2003, CGC's tariff was amended effective January 1, 2003 to require net margin earned by Sequent for transactions involving CGC assets to be shared equally with CGC ratepayers. This agreement expires in April 2006 and is subject to automatic extensions unless specifically terminated by either party. In 2004, Sequent contributed $1.3 million to CGC based upon profits earned during 2003. This contribution will be reflected as a reduction to customer gas cost in 2004.

Peaking services Wholesale services generates operating margin through the sale of peaking services, which includes receiving a fee from customers that guarantees that those customers will receive gas under peak conditions. The primary customer for these peaking services has historically been AGLC. Under these peaking services, wholesale services recorded gross revenues of $6.8 million in the three months ended March 31, 2004 and $6.0 million during the same period in 2003. Our affiliated peaking arrangement expired March 31, 2004. We renewed and extended for 5 years beginning November 2004 and ending March 2009 a separate non-affiliated peaking service agreement.

Wholesale services incurs costs to support its obligations under these agreements, which will be reduced in whole or in part as the matching obligations expire. If these arrangements, including those with AGLC, are renewed, it is likely that future fees may not be reset at current levels. We will continue to seek new peaking transactions as well as work toward extending those that are set, or have expired.

Energy Marketing and Risk Management Activities Sequent recorded unrealized gains of $14.6 million in 2004 and $9.5 million in 2003, excluding the cumulative effect of a change in accounting principle, related to changes in the fair value of derivative instruments utilized in our energy marketing and risk management activities. The tables below illustrate the change in the net fair value of the derivative instruments and energy-trading contracts during the three months ended March 31, 2004 and 2003 and provide details of the net fair value of contracts outstanding as of March 31, 2004. Sequent's storage positions are affected by price sensitivity in the New York Mercantile Exchange, Inc. (NYMEX) average price.

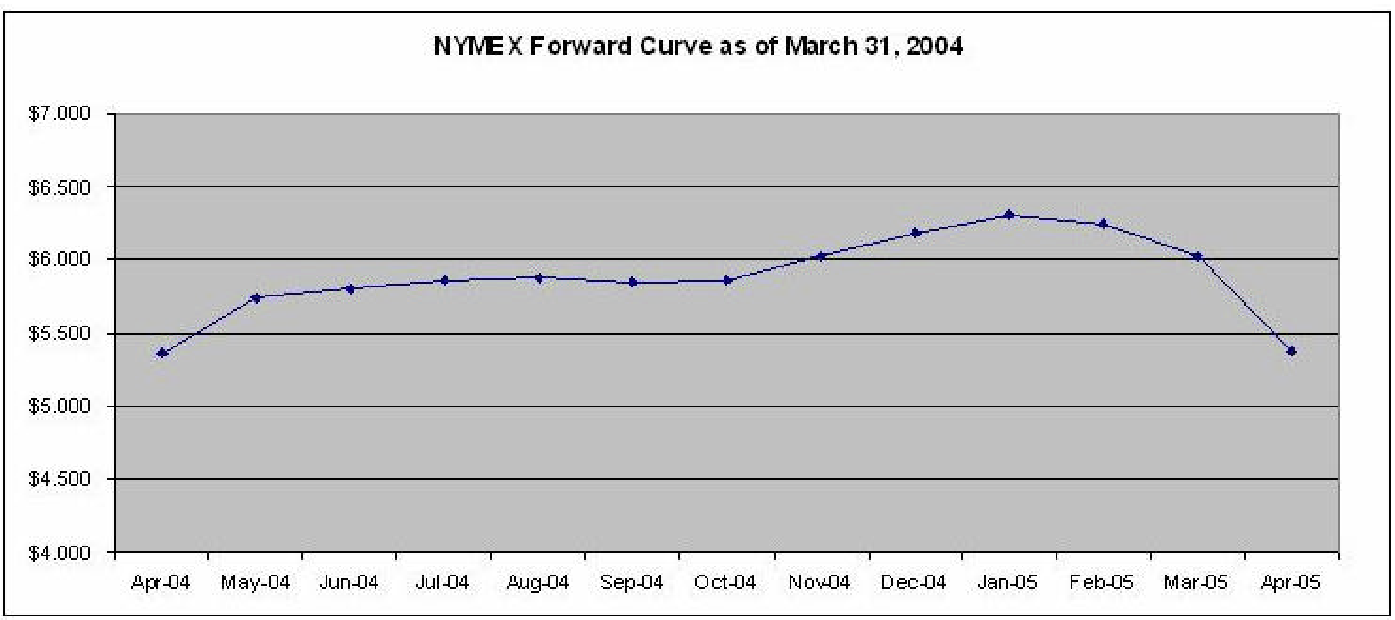
In millions	2004	2003
Net fair value of contracts outstanding at beginning of period	($5.1)	$6.8
Cumulative effect of change in accounting principle	-	(12.6)
Net fair value of contracts outstanding at beginning of period, as adjusted	(5.1)	(5.8)
Contracts realized or otherwise settled during period	4.3	(2.7)
Change in net fair value of contract gains	10.3	12.2
Net fair value of new contracts entered into during period	-	-
Net fair value of contracts outstanding at end of period	$9.5	$3.7

The sources of our net fair value at March 31, 2004 are as follows:

In millions	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)	$9.5	$-	$-	$-	$9.5
Prices provided by other external sources	(0.4)	0.5	-	(0.1)	-

(1) 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 t ransport the commodity from a NYMEX delivery point to the contract delivery point. Our basis spreads are primarily based on quotes obtained either directly from brokers or through electronic trading platforms.

Storage Inventory Outlook The NYMEX forward curve graph set forth below reflects the NYMEX natural gas prices as of March 31, 2004 through April 2005. These are the prices on March 31, 2004 at which we could buy natural gas at the Henry Hub for delivery in the time period of April 2004 through April 2005. April 2004 futures expired on March 29, 2004, however they are included as they coincide with the April storage withdrawals. The Henry Hub, located in Louisiana, is the largest centralized point for natural gas spot and futures trading in the United States. NYMEX uses the Henry Hub as the point of delivery for its natural gas futures contracts. Many natural gas marketers also use the Henry Hub as their physical contract delivery point or their price benchmark for spot trades of natural gas.



“Open futures NYMEX contracts” represents the volume in contract equivalents of the transactions we executed to economically hedge our storage inventory. As of March 31, 2004, the expected withdrawal schedule of this inventory and its weighted average costs are reflected in the entry “physical withdrawal schedule.” Our futures contracts qualify as derivatives under Statement of Financial Accounting Standards (SFAS) No. 133, “Accounting for Derivative Instruments and Hedging Activities” (SFAS 133) and are accounted for at fair value (mark-to-market). However, the storage inventory is accounted for under the accrual method, at the lower of average cost or market, resulting in a timing mismatch in earnings recognition.

We recognize the gains or losses on the futures contracts in the period the price changes; we recognize the gains or losses on the storage inventory as the gas is withdrawn from storage. The schedule also reflects that our storage inventory is fully hedged with futures, which results in an overall locked-in margin, timing notwithstanding. “Expected gross margin after regulatory sharing” reflects the gross margin we would generate in future periods based on the forward curve and inventory withdrawal schedule at March 31, 2004. This gross margin could change as we adjust our daily injection and withdrawal plans due to changes in market conditions.

	Apr. 2004	May 2004	June 2004	July 2004	Aug. 2004	Sept. 2004
Open futures NYMEX contracts (short) long (1)	(123)	(3)	(123)	(51)	(44)	(24)
Physical withdrawal schedule as of March 31, 2004 (NYMEX contract equivalents)						
Salt dome (WACOG (2) = $5.23)	168	27	-	-	-	-
Reservoir (WACOG (2) = $4.52)	(45)	(24)	123	51	44	24
Total	123	3	123	51	44	24
Expected gross margin, after regulatory sharing (3) *(In millions)*						
Reservoir	$-	$0.1	$0.5	$0.2	$0.1	$0.1
Salt dome	0.9	0.2	-	-	-	-

(1) April futures expired on March 29, 2004; however, they are included herein as they coincide with the April storage withdrawals.

(2) WACOG = Weighted average cost of gas

(3) At March 31, 2004, as a result of our positions, a $0.10 parallel change in future NYMEX prices would impact our EBIT by $0.3 million. As shown, our net position is flat, and price movements should only affect timing of earnings between periods as futures contracts are marked to market but inventory is recorded at lower of average cost or market.

Park and Loan Outlook Additionally, we have entered into park and loan transactions with various pipelines. A park and loan transaction is a tariff transaction offered by pipelines, where the pipeline allows the customer to park gas on or borrow gas from the pipeline in one period and reclaim gas from or repay gas to the pipeline in a subsequent period. The economics of these transactions are evaluated and managed similar to the way traditional reservoir and salt dome storage transactions are evaluated. However, these transactions have elements that qualify as derivatives in accordance with SFAS 133.

Under SFAS 133, the transactions are considered financing arrangements when the contracts contain volumes that are payable or repaid at determinable dates and at a specific point in time to third parties. Because these park and loan transactions have fixed volumes, they contain price risk for the change in market prices from the date the transaction is initiated to the time the gas is repaid. As a result, these transactions qualify as derivatives under SFAS 133 that must be recorded at their fair value. Certain park and loan transactions that we execute meet this definition. As such, we account for these transactions at fair value once the transaction has started (either the gas is originally parked on or borrowed from the pipeline). "Park and (loan) volumes" represents the contract equivalent for the volumes of our park and loan transactions as of March 31, 2004 that is not already accounted for at fair value. "Expected gross margin from park and loans" represents the gross margin from those transactions expected to be recognized in future periods based on the forward curves at March 31, 2004.

In millions	Apr. 2004	May 2004	July 2004	Oct. 2004	Nov. 2004	Dec. 2004	May 2005	July 2005	Total
Park and (loan) volumes	-	(0.6)	(1.0)	-	-	-	0.6	1.0	-
Expected gross margin from park and loans	$-	$0.1	$0.2	$-	$-	$-	$-	$-	$0.3

Results of Operations for the three months ended March 31, 2004 and 2003 are as follows:

In millions	2004	2003	2004 vs. 2003
Operating revenues	$20.4	$28.5	($8.1)
Cost of sales	-	0.2	(0.2)
Operating margin	20.4	28.3	(7.9)
Operating expenses			
Operation and maintenance	7.8	7.5	0.3
Depreciation and amortization	0.1	-	0.1
Taxes other than income	0.2	0.1	0.1
Total operating expenses	8.1	7.6	0.5
Operating income	12.3	20.7	(8.4)
Other income	-	-	
EBIT	$12.3	$20.7	($8.4)
Metrics			
Physical sales volumes (Bcf/day)	2.11	1.95	8.2%

2004 compared to 2003

The $8.4 million decline in EBIT is due primarily to lower volatility in the market this year. In addition, our weighted average cost of gas stored inventory sold during the first quarter of 2004 was $5.06 per millions of British thermal units (MMBtu), which was substantially higher than the $2.20 per MMBtu average during the same period last year.

Despite reduced volatility during first quarter 2004, Sequent's sales volumes for the quarter were up 8 percent over the same period last year. Sequent's operating expenses increased $0.5 million, primarily as a result of payroll and related expenses, as a result of an increase in its number of employees.

Energy Investments

Our energy investments segment includes the consolidated results of operations and financial condition of SouthStar in 2004, our equity investment in SouthStar in 2003, the results of operations and financial condition of AGL Networks, LLC (AGL Networks), and our equity investment in US Propane LP (US Propane), through the date of its sale in January 2004.

On January 20, 2004, we executed an agreement to sell our general and limited partnership interests in US Propane. The aggregate transaction was valued at $130 million. Upon closing, we received $29 million for the sale of our interests. We recognized a gain of $0.6 million on this transaction in 2004, which we recorded in other income. We also recorded a $0.5 million unrealized gain in other comprehensive income for the expected June 2004 sale of our investment in marketable equity securities, retained after the sale of US Propane.

- **SouthStar** is a joint venture formed in 1998 by our subsidiary, Georgia Natural Gas Company, Piedmont and Dynegy Inc. (Dynegy) to market natural gas and related services to retail customers, principally in Georgia. On March 11, 2003, we purchased Dynegy's 20% ownership interest in a transaction that for accounting purposes had an effective date of February 18, 2003.

  We currently own a noncontrolling 70% financial interest in SouthStar and Piedmont owns the remaining 30%. Our 70% interest is noncontrolling because all significant management decisions require approval by both owners. On March 29, 2004, we executed an amended and restated partnership agreement with Piedmont. This amended and restated partnership agreement calls for SouthStar's future earnings starting in 2004 to be allocated 75% to our subsidiary and 25% to Piedmont. In addition, we executed a services agreement, which provided that AGL Services Company will provide and administer accounting, treasury, internal audit, human resources and information technology functions.

  Pursuant to our adoption of FIN 46R, we consolidated all of SouthStar's accounts with our subsidiaries' accounts as of March 31, 2004. We recorded Piedmont's portion of SouthStar's earnings as a minority interest in our condensed consolidated statements of income and Piedmont's portion of SouthStar's contributed capital as a minority interest on our condensed consolidated balance sheet. We eliminated any intercompany profits between segments. The following pro-forma condensed consolidated balance sheet and statement of income are presented as if SouthStar's balances were consolidated with our subsidiaries' accounts as of December 31, 2003. These pro-forma amounts are presented for informational purposes and are not necessarily indicative of future operations.

AGL RESOURCES INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEET
DECEMBER 31, 2003
(UNAUDITED)

In millions, except per share amounts	As reported	SouthStar	Eliminations	Pro-forma
Current assets	$747.3	173.9	(10.9)	$910.3
Property, plant and equipment	2,352.4	1.9	-	2,354.3
Deferred debits and other assets (1)	878.1	-	(71.2)	806.9
Total assets	$3,977.8	$175.8	($82.1)	$4,071.5
Current liabilities	$1,054.4	$75.0	($10.9)	$1,118.5
Accumulated deferred income taxes	376.3	-	-	376.3
Long-term liabilities	568.4	-	-	568.4
Deferred credits	77.3	-	-	77.3
Minority interest	-	-	29.6	29.6
Capitalization	1,901.4	100.8	(100.8)	1,901.4
Total liabilities and capitalization	$3,977.8	$175.8	($82.1)	$4,071.5

(1) Our investment in SouthStar was $71.2 million.

AGL RESOURCES INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENT OF INCOME
FOR THE THREE MONTHS ENDED MARCH 31, 2003
(UNAUDITED)

In millions	As reported (1)	SouthStar (2)	Eliminations	Pro-forma
Operating revenues	$352.5	$291.9	($47.7)	$596.7
Operating expenses				
Cost of gas	148.6	246.4	(47.7)	347.3
Operation and maintenance expenses	72.2	18.3	-	90.5
Depreciation and amortization	22.3	0.4	-	22.7
Taxes other than income	7.9	-	-	7.9
Total operating expenses	251.0	265.1	(47.7)	468.4
Operating income	101.5	26.8	-	128.3
Other income	16.0	0.2	(14.4)	1.8
Interest expense and preferred stock dividends	(19.8)	(0.1)	-	(19.9)
Minority interest in income of consolidated subsidiary (3)	-	-	(12.5)	(12.5)
Earnings before income taxes	97.7	26.9	(26.9)	97.7
Income taxes	(38.1)	-	-	(38.1)
Income before cumulative effect of change in accounting principle	59.6	26.9	(26.9)	59.6
Cumulative effect of change in accounting principle, net of taxes	(7.8)	-	-	(7.8)
Net income	$51.8	$26.9	($26.9)	$51.8

(1) We reclassified regulatory carrying charges of $1.1 million from other income to operating revenues.
(2) Includes 100% of SouthStar's revenues and expenses.
(3) Minority interest adjusts our earnings to reflect our 70% share of SouthStar's earnings (less Dynegy Inc.'s 20% share of SouthStar's income prior to February 18, 2003).

- **AGL Networks**, our wholly-owned subsidiary, is a provider of telecommunications conduit and dark fiber. AGL Networks leases and sells its fiber to a variety of customers in the Atlanta, Georgia and Phoenix, Arizona metropolitan areas, with a small presence in other cities in the United States. Its customers include local, regional and national telecommunications companies, internet service providers, educational institutions and other commercial entities.

  AGL Networks typically provides underground conduit and dark fiber to its customers under leasing arrangements with terms that vary from 1 to 20 years. In addition, AGL Networks offers telecommunications construction services to companies. Our primary goals for this business in the next 12 to 15 months are to:

  - increase revenues through our sales efforts
  - maintain control of capital costs for connecting customers to the network
  - maintain control of sales and operating expenses

Results of operations for the three months ended March 31, 2004 and 2003 and pro-forma results for the three months ended March 31, 2003 are shown in the following table. We have included pro-forma results as if SouthStar's accounts were consolidated with our subsidiaries' accounts for the three months ended March 31, 2003. These pro-forma results are presented for informational purposes and are not necessarily indicative of future operations.

In millions	**2004** (1)	**2003**	**Pro-forma 2003** (1)	**2004 vs. 2003**	**2004 vs. Pro-forma 2003**
Operating revenues	$308.5	$3.3	$295.2	$305.2	$13.3
Cost of sales	250.6	0.4	246.8	250.2	3.8
Operating margin	57.9	2.9	48.4	55.0	9.5
Operating expenses					
Operation and maintenance	14.8	2.8	21.0	12.0	(6.2)
Depreciation and amortization	0.5	0.1	0.5	0.4	-
Taxes other than income	0.2	0.1	0.1	0.1	0.1
Total operating expenses	15.5	3.0	21.6	12.5	(6.1)
Operating income (loss)	42.4	(0.1)	26.8	42.5	15.6
Equity earnings from SouthStar	-	14.4	-	(14.4)	-
Other income	0.8	1.7	1.7	(0.9)	(0.9)
Total other income	0.8	16.1	1.7	(15.3)	(0.9)
Minority interest (2)	(11.0)	-	(12.5)	(11.0)	1.5
EBIT	$32.2	$16.0	$16.0	$16.2	$16.2

Metrics					
SouthStar					
Average customers (in thousands) (3)	550.0	562.6	-	(2.2%)	-
Market share in Georgia	36.9%	38.0%	-	(2.9%)	-

(1) Includes 100% of SouthStar's revenues and expenses.
(2) Minority interest adjusts our earnings to reflect our 75% share of SouthStar's earnings in 2004 and our 70% share in 2003 (less Dynegy Inc.'s 20% share of SouthStar's income prior to February 18, 2003).
(3) 12 month average ending March 31.

2004 compared to 2003

The increase in EBIT of $16.2 million for the first quarter 2004 compared to the first quarter 2003 is primarily due to strong results from SouthStar. The improved results at SouthStar primarily reflect higher operating margins and substantially lower bad debt expense, as well as our expanded ownership in the joint venture. The decrease in market share of 2.9% is primarily as a result of the improved credit worthiness of SouthStar's customer base. Beginning in 2004, the amended operating agreement provides for us to receive 75% of SouthStar's earnings.

On a pro-forma basis, the increase in EBIT of $16.2 million for 2004 compared to the 2003, which includes the consolidated results of SouthStar, was due to an increase in operating margin of $9.5 million, a decrease in operating expenses of $6.1 million, and a decrease in minority interest of $1.5 million.

The increase in operating margin of $9.5 million is a result of the following:

- lower gas cost per unit and lower hedging cost in 2004 as compared to 2003 resulted in an increase in margin of $13.0 million, offset by
- one-time sale of gas inventory reassigned to AGLC of $1.5 million in 2003.

The decrease in operating expenses of $6.1 million is a result of the following:

- lower bad debt expenses of $4.1 million caused by ongoing active customer collections and increased quality of customer base.
- lower customer care expense of $1.6 million due to lower system development cost and utilization of vendor credits in 2004.

Minority interest was $1.5 million lower as a result of our increased ownership of SouthStar. Our ownership percentage increased from 50% to 70% on February 18, 2003 and the amended operating agreement of SouthStar provides for us to receive 75% of its earnings beginning in 2004.

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 substantially all of 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.

In August 2003, we formed Pivotal Energy Development (Pivotal) within AGSC. Pivotal coordinates, among our related operating segments, the development, construction or acquisition of assets in the Southeast and Mid-Atlantic regions in order to extend our natural gas capabilities and improve system reliability while enhancing service to our customers in those areas. The initial focus of Pivotal's commercial activities will be to improve the economics of system reliability and natural gas deliverability in these targeted regions.

Results of operations for the three months ended March 31, 2004 and 2003 are as follows:

In millions	**2004**	**2003**	**2004 vs. 2003**
Operating revenues (1)	($66.8)	$-	($66.8)
Cost of sales (1)	(66.8)	-	(66.8)
Operating margin	-	-	-
Total operating expenses	3.5	(0.2)	3.7
Operating (loss) income	(3.5)	0.2	(3.7)
Other loss	(0.4)	(0.3)	(0.1)
EBIT	($3.9)	($0.1)	($3.8)

(1) Reflects the elimination of intercompany profits between segments.

2004 compared to 2003

The decrease in EBIT of $3.8 million for 2004 compared to 2003 was primarily due to an increase in operating expenses of $3.7 million, which we did not allocate to the operating segments. Operating expenses increased as a result of the following:

- $1.8 million increase in legal, consulting and employee-related costs
- $0.9 million increase in corporate governance-related costs allocated to the holding company
- $0.8 million increase in expenses related to Pivotal, which was not in existence last year

Liquidity and Capital Resources

Known Trends and Uncertainties We rely on operating cash flow; short-term borrowings under our commercial paper program, which is backed by our supporting credit agreements (Credit Facility); and borrowings or stock issuances in the long-term capital markets to meet our capital and liquidity requirements. Our issuance of various securities, including long-term and short-term debt, is subject to customary approval or authorization by state and federal regulatory bodies including state public service commissions and the SEC. On April 1, 2004 we received approval from the SEC under PUHCA for the renewal of our financing authority to issue securities through April 2007.

We are currently in the process of renewing our Credit Facility of which $200 million is due to expire on June 16, 2004 and $300 million will expire on August 8, 2005. In the second quarter of 2004, we anticipate closing on a new $500 million Credit Facility with a term of three years. The availability of borrowings and unused availability under our Credit Facility is limited and subject to conditions specified within the Credit Facility, which we currently meet. This availability at March 31, 2004 and December 31, 2003 is represented in the table below. These conditions specified within the Credit Facility include:

- compliance with certain financial covenants
- the continued accuracy of representations and warranties contained in the agreements, and
- our total debt-to-capital ratio

In millions	March 31, 2004	Dec. 31, 2003
Unused availability under the Credit Facility	$500.0	$500.0
Cash and cash equivalents	50.9	16.5
Total cash and available liquidity under the Credit Facility	$550.9	$516.5

For the future, we believe these sources will be sufficient for our working capital needs, debt service obligations and scheduled capital expenditures. The relatively stable operating cash flows of our distribution operations businesses currently contribute a substantial portion of our cash flow from operations and we anticipate this to continue in the future. However, our liquidity and capital resource requirements 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 resulting short-term borrowing requirements, which typically peak during colder months
- increased gas supplies required to meet our customers' needs during cold weather
- regulatory changes and changes in rate-making policies of regulatory commissions
- contractual cash obligations and other commercial commitments
- interest rate changes
- pension and postretirement benefit costs
- changes in income tax laws
- changes in wholesale prices and customer demand for our products and services
- margin requirements resulting from significant increases or decreases in our commodity prices
- operational risks

The following table illustrates our expected future contractual cash obligations as of March 31, 2004:

	Payments Due before December 31,				
In millions	Total	2004	2005 & 2006	2007 & 2008	2009 & Thereafter
Long-term debt (1)	$970.2	-	-	-	970.2
Pipeline charges, storage capacity and gas supply (2)	741.4	209.3	243.5	105.6	183.0
Pipeline replacement program costs (3)	397.1	73.1	162.0	162.0	-
Short-term debt	133.1	133.1	-	-	-
ERC (3)	79.8	32.9	31.4	5.6	9.9
Operating leases (4)	71.6	9.4	18.9	14.5	28.8
Communication/network service and maintenance	18.3	7.3	11.0	-	-
Total	$2,411.5	$465.1	$466.8	$287.7	$1,191.9

(1) Includes $232.0 million of Notes Payable to Trusts, callable in 2006 and 2007.
(2) Charges recoverable through a PGA mechanism or alternatively billed to Marketers.
(3) Charges recoverable through rate rider mechanisms.
(4) 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 No. 13, "Accounting for Leases." However, this accounting treatment does not affect the future annual operating lease cash obligations as shown herein.

FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (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 expected commercial commitments that are outstanding as of March 31, 2004 and meet the disclosure criteria required by FIN 45:

	Commitments Due before December 31,				
In millions	Total	2004	2005 & 2006	2007 & 2008	2009 & Thereafter
Guarantees (1) (2)	$213.5	$213.5	$-	$-	$-
Standby letters of credit, performance/ surety bonds	10.0	10.0	-	-	-
Total other commercial commitments	$223.5	$223.5	$-	$-	$-

(1) $164.2 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.

(2) We provide guarantees on behalf of our subsidiary, 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 $42.3 million, which represents our share of SouthStar's maximum credit support obligation to AGLC under its tariff.

Cash flow provided from operating activities We have historically had a working capital deficit, primarily as a result of our borrowings of short-term debt to finance the purchase of long-term assets, principally property, plant and equipment. Year-to-year changes in our operating cash flows are primarily the result of the following:

- changes in our operating results
- the timing associated with working capital items such as cash collections from our customers and cash receipts or disbursements for our natural gas inventories
- payments for operating expenses to our vendors and employees, income taxes and interest

Our statement of cash flows is prepared using the indirect method. Under this method, net income is reconciled to cash flows from operating activities by adjusting net income for those items that impact net income but do not result in actual cash receipts or payments during the period. These reconciling items include depreciation, undistributed earnings from equity investments, changes in deferred income taxes, gains or losses on the sale of assets and changes in the balance sheet for working capital from the beginning to the end of the period. Our operating cash flows for the first quarter of 2004 include the results of SouthStar as a result of our consolidation of SouthStar effective January 1, 2004. In 2003, our operating cash flow only reflected distributions received from SouthStar consistent with the equity method of accounting.

Our cash flow from operations for the three months ended March 31, 2004 was $335.3 million, an increase of $147.2 million from the same period in 2003. Including the impacts of the consolidation of SouthStar, this increase was primarily the result of cash received of approximately $110 million from the sale of natural gas inventories in excess of cash purchases and increased net income of $13.9 million.

Cash flow used in investing activities Our cash used in investing activities consists primarily of property, plant and equipment expenditures. We made investments of $45.3 million in the three months ended March 31, 2004 and $36.2 million in the same period in 2003. The increase of $9.0 million is primarily from higher expenditures at AGLC and Pivotal Propane.

The increase at AGLC includes a $4.8 million increase in the pipeline replacement program (PRP) as a result of larger diameter and more expensive pipe that has been replaced this year. In addition, the increase reflects increases in other expenditures that include $3.1 million in expenditures for business support, including fleet vehicles, marketer interface automation system and meter reading replacements. The increase of $4.5 million relates to expenditures for the construction of a propane plant in the VNG service area.

These increases were offset by decreased expenditures at AGL Networks of $3.8 million as a result of the completion of our Atlanta and Phoenix networks in 2003. The following table provides additional information on our property, plant and equipment expenditures for the three months ended March 31, 2004 and 2003:

In millions	**2004**	**2003**	**2004 vs. 2003**
Construction of distribution facilities	$14.0	$13.6	$0.4
Pipeline replacement program (1)	12.9	8.1	4.8
Pivotal Propane plant	4.5	-	4.5
Telecommunications	-	3.8	(3.8)
Other	13.9	10.8	3.1
Total property, plant and equipment expenditures	45.3	36.3	9.0
Environmental response costs (2)	10.4	6.9	3.5
Total capital requirements	$55.7	$43.2	$12.5

(1) These expenditures include removal costs. We estimate our total future capital expenditures related to the PRP to be $397.1 million. We estimate our PRP capital expenditures to be $93.3 million in the next twelve months. Capital expenditures under this program are expected to end June 30, 2008, unless the program is extended by the GPSC.

(2) These costs are not included in our cash flows used in investing activities as they are not considered property, plant and equipment expenditures. They are considered a factor in our capital requirements as we estimate our cash requirements for future years.

In 2004, our investing activities also consisted of $29.1 million in cash receipts for the sale of our interests in US Propane. In 2003, we made a payment of $20.0 million for the purchase of Dynegy's 20% interest in SouthStar.

Cash flow used in financing activities In the three months ended March 31, 2004 and 2003, our cash used in financing activities are primarily composed of borrowings and payments of short-term debt, payments of Medium-Term notes, cash dividends on our common stock and the issuance of common stock. Our Credit Facility financial covenants and the PUHCA require us to maintain a ratio of total debt-to-total capitalization of no greater than 70.0%. As of March 31, 2004, we were in compliance with this leverage ratio requirement. The components of our capital structure, as of the dates indicated, are summarized in the following table:

Dollars in millions	March 31, 2004		Dec. 31, 2003	
Short-term debt	$99.6	4.7%	$306.4	13.4%
Current portion of long-term debt	33.5	1.6	77.0	3.3
Senior and Medium-Term notes (1)	733.3	34.4	730.8	32.0
Note payable to capital trust (2)	236.9	11.1	-	-
Trust Preferred Securities (2)	-	-	225.3	9.9
Total debt	1,103.3	51.8	1,339.5	58.6
Minority interest	26.9	1.2	-	-
Common equity	1,001.9	47.0	945.3	41.4
Total capitalization	$2,132.1	100.0%	$2,284.8	100.0%

(1) Net of interest rate swaps of $0.6 million in 2004 and ($6.9) million in 2003.

(2) Net of interest rate swaps of $4.9 million in 2004 and $3.2 million in 2003.

Short-term debt The decrease in our short-term debt of $206.8 million is primarily a result of payments on outstanding commercial paper from:

- cash generated from strong operating results
- positive working capital from lower receivable and inventory requirements
- proceeds from the sale of our ownership interest in US Propane

Long-term Debt For the three months ended March 31, 2004, we made $48.5 million in Medium-Term note payments, as follows:

- In January, 2004, we exercised our option to redeem $43.5 million at a call premium. These notes were scheduled to mature in 2019 with interest rates ranging from 7.0% to 7.1%
- In February 2004, we exercised our option to redeem $5.0 million at a call premium. This note was scheduled to mature in 2014 with a interest rate of 7.0%

Minority interest SouthStar's accounts were combined with our subsidiaries' accounts as of March 31, 2004. As a result, we recorded Piedmont's portion of SouthStar's contributed capital as minority interest on our condensed consolidated balance sheet and is included as a component of our capitalization. In addition, we recorded a cash disbursement of $13.9 million in our cash flows from financing activities for SouthStar's dividend distribution to Piedmont.

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, for the purpose of hedging the interest rate risk associated with our fixed-rate and variable-rate debt obligations. For more discussion of our interest rate swaps, see Note 3, "Risk Management." On March 9, 2004, we terminated an interest rate swap on $100.0 million of the principal amount of our 4.45% Senior Notes Due 2013.

Critical Accounting Policies

The selection and application of critical accounting policies are important processes that have 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" (SFAS 71). 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 statements of consolidated income in the period in which we reflect the same amounts in rates.

If any portion of distribution operations 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 sheets and include them in our statements of consolidated income for the period in which the discontinuance of regulatory accounting treatment occurred.

Pipeline Replacement Program (PRP)

AGLC recorded a long-term liability of $303.8 million as of March 31, 2004 and $322.7 million as of December 31, 2003, which represented engineering estimates for remaining capital expenditure costs in the PRP. As of March 31, 2004, AGLC had recorded a current liability of $93.3 million, representing expected PRP expenditures for the next 12 months. We report these estimates on an undiscounted basis.

The PRP 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. AGLC has subsequently identified an additional 188 miles of pipe subject to replacement under this program. If AGLC does not perform in accordance with this order, AGLC will be assessed certain nonperformance 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 rate riders
- the future expected costs to be recovered through rate riders

Environmental Response Costs (ERC)

AGLC historically reported estimates of future remediation costs based on probabilistic models of potential costs. We report these estimates on an undiscounted basis. As we continue to conduct the actual remediation and enter into 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 further reducing AGLC's total future expenditures. The following table shows components of AGLC's ERC liability as of March 31, 2004 and December 31, 2003:

In millions	March 31, 2004	Dec. 31, 2003	2004 vs. 2003
Projected engineering estimates and in-place contracts (1)	$62.5	$66.4	($3.9)
Estimated future remediation costs (1)	15.2	15.3	(0.1)
Administrative expenses	2.7	2.7	-
Other expenses	9.4	9.4	-
Cash payments for cleanup expenditures (2)	(10.0)	(10.8)	0.8
Accrued ERC	$79.8	$83.0	($3.2)

(1) As of December 31, 2003 and September 30, 2003.
(2) Expenditures during the three months ended March 31, 2004 and December 31, 2003.

Our latest available estimate as of December 31, 2003 for those elements of the MGP program with in-place contracts or engineering cost estimates is $62.5 million. This is a reduction of $3.9 million from the estimate as of September 30, 2003. For elements of the MGP program where AGLC still cannot perform engineering cost estimates, considerable variability remains in available estimates. For these elements, the estimated remaining cost of future actions at MGP sites is $15.2 million.

AGLC estimates certain other costs paid directly by AGLC related to administering the MGP program and remediation of sites currently in the investigation phase. Through January 2005, AGLC estimates the administration costs to be $2.7 million. Beyond January 2005, these costs are not estimable. For those sites currently in the investigation phase our estimate is $9.4 million, which is based upon preliminary data received during 2003 with respect to the existence of contamination of those sites. Our range of estimates for these sites is from $9.4 million to $15.1 million. We have accrued the low end of our range, or $9.4 million, as this is our best estimate at this phase of the remediation process.

We included the ERC liability in a corresponding regulatory asset. As of March 31, 2004, the regulatory asset was $180.0 million, which is a combination of the accrued ERC 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 referenced above.

Derivatives 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 treatment 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 treatment is 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. Additionally, SFAS 133 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 applies are interest rate swaps and gas commodity contracts at both Sequent and SouthStar.

Interest rate swaps We designate our 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.

Commodity-related derivative instruments We are exposed to risks associated with changes in the market of natural gas. Through Sequent and SouthStar, we use derivative instruments to reduce our exposure to the risk of changes in the prices of natural gas. When the portfolio market value changes, primarily due to newly originated transactions and the effect of price changes, Sequent recognizes the change in value of derivative instruments as a gain or loss in revenues in the period of change. Sequent recognizes cash inflows and outflows associated with settlement of these risk management activities in operating cash flows, and Sequent reports these settlements as receivables and payables separately from risk management activities in the balance sheet as energy marketing receivables and trade payables.

SouthStar also uses derivative instruments to manage exposures arising from changing commodity prices. SouthStar's objective for holding these derivatives is to minimize this risk using the most effective methods to reduce or eliminate the impacts of these exposures. A significant portion of SouthStar's derivative transactions are designated as cash flow hedges under SFAS 133. Derivative gains or losses arising from cash flow hedges are recorded in other comprehensive income (OCI) and are reclassified into earnings in the same period as the settlement of the underlying hedged item. Any hedge ineffectiveness, defined as when the gains or losses on the hedging instrument do not perfectly offset the losses or gains on the hedged item, is recorded into earnings in the period in which it occurs. SouthStar currently has no hedge ineffectiveness. The remainder of SouthStar's derivative instruments does not meet the hedge criteria under SFAS 133. Therefore, changes in their fair value are recorded in earnings in the period of change.

Revenue Recognition

Distribution Operations

The VNG and CGC rate structures 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 WNA 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 WNA 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 wholesale services 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.

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 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 last meter reading date to the end of 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 consolidated balance sheets.

In addition, AGL Networks recognizes sales revenues upon the execution of certain sales-type agreements for dark fiber when the agreement provides for the transfer of legal title of 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" (EITF 00-11), and SFAS No. 66, "Accounting for Sales of Real Estate" (SFAS 66), which provide that such transactions meet the criteria for sales-type lease accounting if the agreement obligates the lessor to convey ownership of the underlying asset to the lessee by the end of the lease term.

The dark fiber IRUs obligate AGL Networks 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. Revenues and associated expenses are recorded as projects are considered substantially complete upon customer acceptance.

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" (SFAS 5). 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 our assumptions about the discount rate, expected return on plan assets and rate of future compensation increases. 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.

At December 31, 2003, we reduced our minimum pension liability by approximately $13.7 million, which resulted in an after-tax gain to OCI of $8.2 million. This reflects the impact of our 2003 funding contributions to the plan and updated valuations for the projected benefit obligation and plan assets. 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 accumulated benefit obligation (ABO). 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 in the assumed discount rate would have a negative impact on the ABO of approximately $30.5 million and would decrease pension expense by approximately $2.5 million. A one-percentage-point decrease in the assumed discount rate would have a positive impact on the ABO of approximately $34.0 million and would increase pension expense by approximately $2.5 million. Additionally, a one-percentage-point increase or decrease in the expected return on assets would decrease or increase our pension expense by approximately $2.7 million.

As of March 31, 2004, the market value of the pension assets was $263.4 million compared to a market value of $258.9 million as of December 31, 2003. The net increase of $4.5 million resulted from an actual return on plan assets of $9.5 million less $5.0 million of benefits paid.

The actual return on plan assets compared to the expected return on plan assets will have an impact on our benefit obligation as of December 31, 2004 and our pension expense for 2005. 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, 2004. Our actual returns may also be positively or negatively impacted as a result of future performance in the equity and bond markets.

Accounting Developments

FASB Staff Position 106-1

Effective December 8, 2003, the “Medicare Prescription Drug, Improvement and Modernization Act of 2003” (Medicare Prescription Drug Act) was signed into law, which provides for a prescription drug benefit under Medicare (Part D) as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. Our defined benefit postretirement health care and life insurance plans do provide a prescription drug benefit.

On January 12, 2004, the FASB issued FASB Staff Position (FSP) 106-1, “Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003” (FSP 106-1), which allowed companies to elect a one-time deferral of the recognition of the effects of the Medicare Prescription Drug Act in accounting for their plans under SFAS 106 and in providing disclosures related to the plan required by SFAS 132 (revised 2003). The FASB allowed the one-time deferral due to the accounting issues raised by the Medicare Prescription Drug Act--in particular, the accounting for the federal subsidy that is not explicitly addressed in SFAS 106--and due to the fact that uncertainties exist as to the direct effects of the Medicare Prescription Drug Act and its ancillary effects on plan participants.

For companies electing the one-time deferral, such deferral remains in effect until authoritative guidance on the accounting for the federal subsidy is issued, or until certain other events, such as a plan amendment, settlement or curtailment, occur. As of December 31, 2003, we elected the one-time deferral. Our accumulated postretirement obligation or net periodic postretirement benefit cost for 2003 and 2004 does not reflect the effects of the Medicare Prescription Drug Act on our other postretirement plan since specific authoritative guidance on the accounting for the federal subsidy has not been issued and we have not made any amendments to our postretirement plan. Once specific authoritative guidance on the accounting for the federal subsidy is issued, it could result in a change to previously reported information.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to risks associated with commodity prices, interest rates and credit. In the following discussions, we hold all financial instruments for purposes other than trading except at Sequent and SouthStar. 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 at AGLC in distribution operations and in wholesale services.

Our Risk Management Committee (RMC) is responsible for the overall establishment of risk management policies and the monitoring of compliance with and adherence to the terms within these policies, including 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, and 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 This 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 maximum terms of these maturities are less than 2 years and represent purchases (long) of 487.0 Bcf and sales (short) of 477.1 Bcf, with approximately 96% of these scheduled to mature in less than 2 years and the remaining 4% in 3-9 years.

The following table includes the fair values and average values of our energy marketing and risk management assets and liabilities as of March 31, 2004 and December 31, 2003. We base the average values on monthly averages for the three months ended March 31, 2004 and 12 months ended December 31, 2003.

	Asset			
	Average Values		Value at:	
In millions	3 months ended March 31, 2004	12 months ended Dec. 31, 2003	March 31, 2004	Dec. 31, 2003
Natural gas contracts	$22.9	$13.6	$30.0	$13.2

	Liability			
	Average Values		Value at:	
In millions	3 months ended March 31, 2004	12 months ended Dec. 31, 2003	March 31, 2004	Dec. 31, 2003
Natural gas contracts	$13.9	$14.3	$20.5	$18.3

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 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 a 1-day and a 10-day holding period 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 over the holding period. 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 our 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 10-day holding period for all positions, our portfolio of positions for the 3 months ended March 31, 2004 had the following 1-day and 10-day holding period VaRs:

In millions	1-day	10-day
Period end	$0.0	$0.1
3-month average	$0.1	$0.2
High	$0.4	$1.2
Low (1)	$0.0	$0.0

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

Our VaR for the twelve months ended December 31, 2003 had the following 1-day and 10-day holding period VaRs:

In millions	1-day	10-day
Period end	$0.3	$1.0
12-month average	0.1	0.3
High	2.5	4.7
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 stored gas. We purchase gas for storage when the current market price we pay for 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 the date 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 consolidated balance sheets 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 statement 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 the sale of stored 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 gas storage 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 gas storage inventory will be offset by losses or gains on the derivatives, resulting in 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. 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
- salt dome high-deliverability storage, where supplies may be periodically injected and withdrawn on relatively short notice

Energy Investments SouthStar utilizes financial contracts to hedge the price volatility of natural gas. SouthStar considers these financial contracts (futures, options and swaps) to be derivatives, with prices based on selected market indices. SouthStar reflects the derivative transactions that qualify as cash flow hedges in its balance sheet at the fair values of the open positions with the corresponding unrealized gain or loss included in OCI. SouthStar reflects the derivatives transactions that are not designated as hedges in its balance sheet with the corresponding unrealized gains or losses included in cost of sales in SouthStar's statement of income. The maximum maturity of open positions is less than two years and represent purchases of 5.5 Bcf and sales of 3.9 Bcf, with approximately 97% scheduled to mature in less than one year.

SouthStar's use of derivatives is governed by a risk management policy which prohibits the use of derivatives for speculative purposes. This policy also establishes VaR limits of $0.5 million on a 1 day holding period and $1.0 million on a 20 day holding period. A 95% confidence interval is used to evaluate VaR exposure. The maximum VaR experienced during the three months ended March 31, 2004 was less than $0.1 million for the 1-day holding period and $0.1 million for the 20-day holding period.

SouthStar also enters into weather derivative contracts for hedging purposes in order to preserve margins in the event of warmer-than-normal weather in the winter months. SouthStar accounts for these contracts using the intrinsic value method under the guidelines of EITF 99-02, "Accounting for Weather Derivatives". Approximately 89% of SouthStar's residential customers buy gas on a pure variable-price basis, with the remaining 11% buying 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-rate and variable-rate debt. To facilitate the achievement of desired fixed to variable-rate debt ratios, AGL Capital entered into interest rate swaps, whereby it agreed to exchange, at specified intervals, the difference between fixed and variable amounts calculated by reference to agreed-upon notional principal amounts.

As of March 31, 2004, $33.5 million of long-term fixed-rate obligations are scheduled to mature in the following 12 months. Any new debt obtained to refinance this obligation would be exposed to changes in interest rates. At March 31, 2004, a 100-bps change in market interest rates from 1.4% to 2.4% on our variable rate debt would result in an increase in our quarterly pretax interest expense of $0.7 million.

As shown in the following table, these swaps are designated to hedge the fair values of $100.0 million of the Senior Notes Due 2011 and $75.0 million of our notes payable to the capital trusts due in 2041. On March 9, 2004, we terminated an interest rate swap on $100.0 million of the principal amount of our 4.45% Senior Notes Due 2013. The fee on this termination was $0.2 million. Additionally, as of March 31, 2004 and in connection with the deconsolidation of the Trusts, we re-designated the interest rate swaps on the Trust Preferred Securities as a fair value hedge of our notes payable to the Trusts.

Market Value of Interest Rate Swap Derivatives

Dollars in millions

				Market Value as of:	
Notional Amount	Fixed-Rate Payment	Variable Rate Received	Maturity	March 31, 2004	Dec.31, 2003
$75.0	8.0%	3-month LIBOR (1) Plus 131.5 bps (2)	May 15, 2041	$4.9	$3.2
$100.0	7.1%	6-month LIBOR Plus 340.0 bps	January 14, 2011	0.6	(1.8)

(1) London Interbank Offered Rate.
(2) Basis points.

Credit Risk

Distribution Operations AGLC has a concentration of credit risk where we charge out and collect from Marketers and poolers, costs for this segment. AGLC bills 10 Marketers in Georgia for its services. The credit risk exposure to Marketers varies with the time of the year with exposure at its lowest in the nonpeak 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 three months ended March 31, 2004, the four largest Marketers based on customer count, one of which was SouthStar, accounted for approximately 52% of distribution operations' operating margin.

In addition, AGLC bills intrastate delivery service to Marketers in advance rather than in arrears. We require security support in the form of cash deposits, letters of credit or 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 assigns this capacity to 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 Marketers to maintain security for their obligations to the interstate pipelines arising out of the assigned capacity somewhat mitigates this risk.

Wholesale Services Sequent has established credit policies to determine and monitor the creditworthiness of counterparties, as well as the quality of pledged collateral. Sequent also utilizes 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. Sequent also uses other netting agreements with certain counterparties with whom 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 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 internal 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. Generally, we require credit enhancements by way of guaranty, cash deposit or letter of credit for transaction counterparties that do not meet the minimum ratings threshold.

Sequent, which provides services to Marketers and utility and industrial customers, also has a concentration of credit risk as measured by its 30-day receivable exposure plus forward exposure. As of March 31, 2004, Sequent's top 20 counterparties represented approximately 67% of the total counterparty exposure of $159.5 million, derived by adding the top 20 counterparties' exposures divided by the total of Sequent's counterparties' exposures.

During 2004, Sequent refined its calculation used to determine the Standard & Poor's (S&P) equivalent credit rating for counterparties in order to reflect various sub-categories of ratings. The S&P equivalent credit rating is determined by a process of converting the lower of the S&P or Moody's Investors Service, Inc. (Moody's) rating to an internal rating ranging from 9.00 to 1.00, with 9.00 being equivalent to AAA/Aaa by S&P and Moody's and 1.00 being D or Default by S&P and Moody's. A counterparty that does not have an external rating is assigned an internal rating based on the strength of the financial ratios of the counterparty.

The weighted average credit rating is obtained by multiplying each counterparty's assigned internal rating by the counterparty's credit exposure and summed for all counterparties. That total is divided by the aggregate total counterparties' exposure. This numeric value is converted to an S&P equivalent. Under the refined methodology, Sequent's counterparties, or the counterparties' guarantors, had a weighted average S&P equivalent credit rating of BBB+ at March 31, 2004 and December 31, 2003, compared with our previously reported rating of BBB at December 31, 2003 under our prior methodology.

To arrive at the weighted average credit rating, the assigned internal rating for each counterparty is multiplied by the counterparty's credit exposure and summed for all counterparties. That sum is divided by the aggregate total counterparties' exposures, and this numeric value is then converted to an S&P equivalent. The following tables show Sequent's commodity receivable and payable positions as of March 31, 2004 and December 31, 2003:

Gross receivables

In millions	March 31, 2004	Dec. 31, 2003	Change
Receivables with netting agreements in place:			
Counterparty is investment grade	$232.5	$288.3	($55.8)
Counterparty is non-investment grade	7.9	13.1	(5.2)
Counterparty has no external rating	11.3	8.8	2.5
Receivables without netting agreements in place:			
Counterparty is investment grade	16.6	14.7	1.9
Counterparty is non-investment grade	-	-	-
Counterparty has no external rating	-	-	-
Amount recorded on balance sheet	$268.3	$324.9	($56.6)

Gross payables

In millions	March 31, 2004	Dec. 31, 2003	Change
Payables with netting agreements in place:			
Counterparty is investment grade	$189.4	$205.4	($16.0)
Counterparty is non-investment grade	33.1	31.4	1.7
Counterparty has no external rating	49.7	45.0	4.7
Payables without netting agreements in place:			
Counterparty is investment grade	43.4	29.3	14.1
Counterparty is non-investment grade	2.7	2.5	0.2
Counterparty has no external rating	-	15.4	(15.4)
Amount recorded on balance sheet	$318.3	$329.0	($10.7)

Energy Investments SouthStar has established the following credit guidelines and risk management practices for each customer type:

- SouthStar scores firm residential and small commercial customers using a national reporting agency and enrolls, without security, only those customers that meet or exceed SouthStar's credit threshold.
- SouthStar determines the credit worthiness of potential interruptible and large commercial customers through reference checks, review of publicly available financial statements and review of commercially available credit reports.
- SouthStar assigns 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 D&B ratings, 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 included fraud and deceit and damages to realty. The allegations arose from negotiations between the city and AGLC regarding our environmental cleanup obligations connected with AGLC's former MGP operations in Augusta. This litigation has been settled and the lawsuit dismissed. For more information about our manufactured gas plants and our environmental cleanup obligations, please see Item 1, Financial Statements, Note 4 "Regulatory Assets and Liabilities – Environmental Response Costs."

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, USE OF PROCEEDS AND ISSUER PURCHASES OF EQUITY SECURITIES

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

10 SouthStar Energy Services LLC Agreement dated April 1, 2004 by and between Georgia Natural Gas Company and Piedmont Energy Company

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

32 Section 1350 Certifications

(b) Reports on Form 8-K.

Date	Event Reported
January 15, 2004	Furnished under Item 9 – Regulation FD Disclosure
January 28, 2004	Furnished under Item 12 – Results of Operation and Financial Condition and Item 9 – Regulation FD Disclosure
January 28, 2004	Filed under Item 5 – Other Events

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: April 28, 2004

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