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

FORM 10-Q

(Mark One)

☑ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Quarterly Period Ended March 31, 2009

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)

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 ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☐ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer,” ”accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☑	Accelerated filer ☐
Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Exchange Act Rule 12b-2). Yes ☐ 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, 2009**
Common Stock, $5.00 Par Value	77,170,946

AGL RESOURCES INC.

Quarterly Report on Form 10-Q

For the Quarter Ended March 31, 2009

TABLE OF CONTENTS

GLOSSARY OF KEY TERMS

AGL Capital	AGL Capital Corporation
AGL Networks	AGL Networks, LLC
Atlanta Gas Light	Atlanta Gas Light Company
Bcf	Billion cubic feet
Chattanooga Gas	Chattanooga Gas Company
Credit Facilities	Credit agreements supporting our commercial paper program
EBIT	Earnings before interest and taxes, a non-GAAP measure that includes operating income, other income and gain on sales of assets and excludes interest expense, and income tax expense; as an indicator of our operating performance, EBIT should not be considered an alternative to, or more meaningful than, operating income, net income, or net income attributable to AGL Resources Inc. as determined in accordance with GAAP
EITF	Emerging Issues Task Force
ERC	Environmental remediation costs associated with our distribution operations segment which are recoverable through rates mechanisms
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN	FASB Interpretation Number
Fitch	Fitch Ratings
FSP	FASB Staff Position
GAAP	Accounting principles generally accepted in the United States of America
Georgia Commission	Georgia Public Service Commission
GNG	Georgia Natural Gas, the name under which SouthStar does business in Georgia
GNGC	Georgia Natural Gas Company, our wholly-owned subsidiary that owns our 70% interest in SouthStar
Golden Triangle Storage	Golden Triangle Storage, Inc.
Heating Degree Days	A measure of the effects of weather on our businesses, calculated when the average daily actual temperatures are less than a baseline temperature of 65 degrees Fahrenheit.
Heating Season	The period from November through March when natural gas usage and operating revenues are generally higher because more customers are connected to our distribution systems when weather is colder
Jefferson Island	Jefferson Island Storage & Hub, LLC
LOCOM	Lower of weighted average cost or current market price
Maryland Commission	Maryland Public Service Commission
Marketers	Marketers selling retail natural gas in Georgia and certificated by the Georgia Commission
Moody's	Moody's Investors Service
New Jersey Commission	New Jersey Board of Public Utilities
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 or loss on the sale of our assets; these items are included in our calculation of operating income as reflected in our condensed consolidated statements of income. Operating margin should not be considered an alternative to, or more meaningful than, operating income, net income, or net income attributable to AGL Resources Inc. as determined in accordance with GAAP
OTC	Over-the-counter
Piedmont	Piedmont Natural Gas
Pivotal Utility	Pivotal Utility Holdings, Inc., doing business as Elizabethtown Gas, Elkton Gas and Florida City Gas
PP&E	Property, plant and equipment
PRP	Pipeline replacement program for Atlanta Gas Light
S&P	Standard & Poor's Ratings Services
SEC	Securities and Exchange Commission
Sequent	Sequent Energy Management, L.P.
SFAS	Statement of Financial Accounting Standards
SouthStar	SouthStar Energy Services LLC
VaR	Value at risk 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
Virginia Natural Gas	Virginia Natural Gas, Inc.
WACOG	Weighted average cost of gas
WNA	Weather normalization adjustment

REFERENCED ACCOUNTING STANDARDS

FIN 46 & FIN 46R	FIN 46, "Consolidation of Variable Interest Entities"
FIN 48	FIN 48, "Accounting for Uncertainty in Income Taxes, an interpretation of SFAS Statement No. 109"
FSP EITF 03-6-1	FSP EITF 03-6-1, "Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities"
FSP EITF 06-3	FSP EITF 06-3, "How Taxes Collected from Customers and Remitted to Governmental Authorities Should be Presented in the Income Statement (That Is, Gross versus Net Presentation)"
FSP FAS 132(R)-1	FSP No. FAS 132(R)-1, "Employers' Disclosures about Postretirement Benefit Plan Assets"
FSP FAS 133-1	FSP No. FAS 133-1, "Disclosures about Credit Derivatives and Certain Guarantees: An Amendment of FASB Statement No. 133"
FSP FAS 157-3	FSP No. FAS 157-3, "Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active"
SFAS 71	SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation"
SFAS 133	SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities"
SFAS 141	SFAS No. 141, "Business Combinations"
SFAS 157	SFAS No. 157, "Fair Value Measurements"
SFAS 160	SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements"
SFAS 161	SFAS No. 161, "Disclosure about Derivative Instruments and Hedging Activities, an amendment of SFAS 133"

PART 1 – Financial Information
Item 1. Financial Statements

AGL RESOURCES INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF FINANCIAL POSITION
(UNAUDITED)

In millions, except share data	March 31, 2009	As of December 31, 2008	March 31, 2008
Current assets			
Cash and cash equivalents	$21	$16	$20
Receivables			
Gas, unbilled and other receivables	458	472	480
Energy marketing receivables	326	549	624
Less allowance for uncollectible accounts	(20)	(16)	(18)
Total receivables	764	1,005	1,086
Inventory, net (Note 1)	348	663	356
Derivative financial instruments – current portion (Note 2 and Note 3)	202	207	56
Unrecovered pipeline replacement program costs – current portion (Note 1)	42	41	35
Unrecovered environmental remediation costs – current portion (Note 1)	16	18	21
Other current assets	38	92	52
Total current assets	1,431	2,042	1,626
Long-term assets and other deferred debits			
Property, plant and equipment	5,592	5,500	5,222
Less accumulated depreciation	1,706	1,684	1,612
Property, plant and equipment-net	3,886	3,816	3,610
Goodwill	418	418	420
Unrecovered pipeline replacement program costs (Note 1)	177	196	236
Unrecovered environmental remediation costs (Note 1)	121	125	130
Derivative financial instruments (Note 2 and Note 3)	48	38	11
Other	76	75	73
Total long-term assets and other deferred debits	4,726	4,668	4,480
Total assets	$6,157	$6,710	$6,106
Current liabilities			
Short-term debt (Note 6)	$403	$866	$369
Energy marketing trade payables	342	539	711
Accounts payable - trade	193	202	166
Accrued expenses	151	113	125
Customer deposits	58	50	34
Derivative financial instruments – current portion (Note 2 and Note 3)	43	50	37
Accrued pipeline replacement program costs – current portion (Note 1)	43	49	55
Deferred natural gas costs	33	25	38
Accrued environmental remediation liabilities – current portion (Note 1)	20	17	13
Other current liabilities	62	72	58
Total current liabilities	1,348	1,983	1,606
Long-term liabilities and other deferred credits			
Long-term debt (Note 6)	1,675	1,675	1,516
Accumulated deferred income taxes	586	571	570
Accumulated removal costs	194	178	173
Accrued pension obligations (Note 4)	188	199	43
Accrued pipeline replacement program costs (Note 1)	126	140	176
Accrued environmental remediation liabilities (Note 1)	85	89	92
Accrued postretirement benefit costs (Note 4)	45	46	22
Derivative financial instruments (Note 2 and Note 3)	8	6	5
Other long-term liabilities and other deferred credits	139	139	149
Total long-term liabilities and other deferred credits	3,046	3,043	2,746
Commitments and contingencies (Note 7)			
Equity (Note 5)			
AGL Resources Inc. common shareholders' equity, $5 par value; 750,000,000 shares authorized	1,734	1,652	1,722
Noncontrolling interest	29	32	32
Total equity	1,763	1,684	1,754
Total liabilities and equity	$6,157	$6,710	$6,106

See Notes to Condensed Consolidated Financial Statements (Unaudited).

AGL RESOURCES INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(UNAUDITED)

	Three months ended March 31,	
In millions, except per share amounts	2009	2008
Operating revenues	$995	$1,012
Operating expenses		
Cost of gas	589	657
Operation and maintenance	125	119
Depreciation and amortization	39	36
Taxes other than income taxes	12	12
Total operating expenses	765	824
Operating income	230	188
Other income	2	1
Interest expense, net	(25)	(30)
Earnings before income taxes	207	159
Income tax expense	72	54
Net income	135	105
Less net income attributable to the noncontrolling interest (Note 5)	16	16
Net income attributable to AGL Resources Inc.	$119	$89
Per common share data (Note 1)		
Basic earnings per common share attributable to AGL Resources Inc. common shareholders	$1.55	$1.17
Diluted earnings per common share attributable to AGL Resources Inc. common shareholders	$1.55	$1.16
Cash dividends declared per common share	$0.43	$0.42
Weighted average number of common shares outstanding (Note 1)		
Basic	76.7	76.0
Diluted	76.8	76.3

See Notes to Condensed Consolidated Financial Statements (Unaudited).

AGL RESOURCES INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF EQUITY
(UNAUDITED)

	AGL Resources Inc. Shareholders							
In millions, except per share amount	Common stock Shares	Common stock Amount	Premium on common stock	Earnings reinvested	Accumulated other comprehensive loss	Shares held in treasury and trust	Noncontrolling interest	Total
Balance as of December 31, 2008	76.9	$390	$676	$763	$(134)	$(43)	$32	$1,684
Net income	-	-	-	119	-	-	16	135
Other comprehensive loss	-	-	-	-	(7)	-	(4)	(11)
Dividends on common stock ($0.43 per share)	-	-	-	(33)	-	1	-	(32)
Distributions to noncontrolling interest	-	-	-	-	-	-	(15)	(15)
Issuance of treasury shares	0.3	-	(6)	(2)	-	9	-	1
Stock-based compensation expense (net of taxes) (Note 5)	-	-	1	-	-	-	-	1
Balance as of March 31, 2009	77.2	$390	$671	$847	$(141)	$(33)	$29	$1,763

See Notes to Condensed Consolidated Financial Statements (Unaudited).

AGL RESOURCES INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

		Components of other comprehensive loss (net of taxes)			
		Cash flow hedges			
In millions	Net income	Derivative financial instruments unrealized (losses) gains arising during the period	Reclassification of derivative financial instruments realized losses (gains) included in net income	Other comprehensive loss	Comprehensive income (Note 5)
Three months ended March 31, 2009:					
AGL Resources	$119	$(9)	$2	$(7)	$112
Noncontrolling interest	16	(5)	1	(4)	12
Consolidated	$135	$(14)	$3	$(11)	$124
Three months ended March 31, 2008:					
AGL Resources	$89	$2	$(4)	$(2)	$87
Noncontrolling interest	16	1	(2)	(1)	15
Consolidated	$105	$3	$(6)	$(3)	$102

See Notes to Condensed Consolidated Financial Statements (Unaudited).

AGL RESOURCES INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(UNAUDITED)

In millions	Three months ended March 31, 2009	2008
Cash flows from operating activities		
Net income	$135	$105
Adjustments to reconcile net income to net cash flow provided by operating activities		
Depreciation and amortization	39	36
Change in derivative financial instrument assets and liabilities	(10)	36
Deferred income taxes	(10)	(18)
Changes in certain assets and liabilities		
Inventories	315	195
Accrued expenses	38	38
Energy marketing receivables and energy marketing trade payables, net	26	107
Gas, unbilled and other receivables	18	(71)
Gas and trade payables	(9)	(6)
Other – net	69	89
Net cash flow provided by operating activities	611	511
Cash flows from investing activities		
Payments to acquire, property, plant and equipment	(97)	(80)
Net cash flow used in investing activities	(97)	(80)
Cash flows from financing activities		
Net payments and borrowings of short-term debt	(463)	(324)
Dividends paid on common shares	(32)	(31)
Distribution to noncontrolling interest	(15)	(30)
Payments of long-term debt	-	(47)
Issuance of treasury shares	1	2
Net cash flow used in financing activities	(509)	(430)
Net increase in cash and cash equivalents	5	1
Cash and cash equivalents at beginning of period	16	19
Cash and cash equivalents at end of period	$21	$20
Cash paid during the period for		
Interest	$29	$34
Income taxes	$16	$2

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 its operations through its subsidiaries. Unless the context requires otherwise, references to “we,” “us,” “our,” or “the company” mean consolidated AGL Resources Inc. and its subsidiaries (AGL Resources).

The year-end condensed statement of financial position data was derived from our audited financial statements, but does not include all disclosures required by GAAP. We have prepared the accompanying unaudited condensed consolidated financial statements under the rules of the SEC. Under such rules and regulations, we have condensed or omitted certain information and notes normally included in financial statements prepared in conformity with GAAP. However, the condensed consolidated financial statements reflect all adjustments of a normal recurring nature that are, in the opinion of management, necessary for a fair presentation of our financial results for the interim periods. For a glossary of key terms and referenced accounting standards, see page 3. You should read these condensed consolidated financial statements in conjunction with our consolidated financial statements and related notes included in our Annual Report on Form 10-K for the year ended December 31, 2008, filed with the SEC on February 5, 2009.

Due to the seasonal nature of our business, our results of operations for the three months ended March 31, 2009 and 2008, and our financial condition as of December 31, 2008, and March 31, 2009 and 2008, are not necessarily indicative of the results of operations and financial condition to be expected as of or for any other period.

Basis of Presentation

Our condensed consolidated financial statements 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. This means that our accounts are combined with our subsidiaries’ accounts. We have eliminated any intercompany profits and transactions in consolidation; however, we have not eliminated intercompany profits when such amounts are probable of recovery under the affiliates’ rate regulation process. Certain amounts from prior periods have been reclassified and revised to conform to the current period presentation.

Use of Accounting Estimates

The preparation of our financial statements in conformity with GAAP requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosures of contingent assets and liabilities. We based our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances, and we evaluate our estimates on an ongoing basis. Each of our estimates involves complex situations requiring a high degree of judgment either in the application and interpretation of existing financial accounting literature or in the development of estimates that impact our financial statements. The most significant estimates include our PRP accruals, environmental liability accruals, allowance for uncollectible accounts and other allowance for contingencies, pension and postretirement obligations, derivative and hedging activities, unbilled revenues and provision for income taxes. Our actual results could differ from our estimates, and such differences could be material.

Energy Marketing Receivables and Payables

Our wholesale services segment provides services to retail marketers and utility and industrial customers. These customers, also known as counterparties, utilize netting agreements, which enable wholesale services to net receivables and payables by counterparty. Wholesale services also nets across product lines and against cash collateral, provided the master netting and cash collateral agreements include such provisions. The amounts due from or owed to wholesale services’ counterparties are netted and recorded on our condensed consolidated statements of financial position as energy marketing receivables and energy marketing payables.

Wholesale services has some trade and credit contracts that have explicit minimum credit rating requirements. These credit rating requirements typically give counterparties the right to suspend or terminate credit if our credit ratings are downgraded to non-investment grade status. Under such circumstances, wholesale services would need to post collateral to continue transacting business with some of its counterparties. Posting collateral would have a negative effect on our liquidity. If such collateral were not posted, wholesale services ability to continue transacting business with these counterparties would be impaired.

Inventories

For our distribution operations segment, we record natural gas stored underground at WACOG. For Sequent and SouthStar, we account for natural gas inventory at the lower of WACOG or market price.

Sequent and SouthStar evaluate the average cost of their natural gas inventories against market prices to determine whether any declines in market prices below the WACOG are other than temporary. For any declines considered to be other than temporary, we record adjustments to reduce the weighted average cost of the natural gas inventory to market price. SouthStar recorded LOCOM adjustments of $6 million in the three months ended March 31, 2009 and did not record LOCOM adjustments in the three months ended March 31, 2008. Sequent recorded LOCOM adjustments of $8 million in the three months ended March 31, 2009 and did not record LOCOM adjustments for the three months ended March 31, 2008.

Regulatory Assets and Liabilities

We have recorded regulatory assets and liabilities in our condensed consolidated statements of financial position in accordance with SFAS 71. Our regulatory assets and liabilities, and associated liabilities for our unrecovered PRP costs, unrecovered ERC and the associated assets and liabilities for our Elizabethtown Gas derivative financial instruments, are summarized in the following table.

In millions	Mar. 31 2009	Dec. 31 2008	Mar. 31 2008
Regulatory assets			
Unrecovered PRP costs	$219	$237	$271
Unrecovered ERC	137	143	151
Unrecovered postretirement benefit costs	11	11	12
Unrecovered seasonal rates	-	11	-
Unrecovered natural gas costs	-	19	18
Elizabethtown Gas derivative financial instruments	-	-	16
Other	28	30	24
Total regulatory assets	395	451	492
Associated assets			
Elizabethtown Gas derivative financial instruments	29	23	-
Total regulatory and associated assets	$424	$474	$492
Regulatory liabilities			
Accumulated removal costs	$194	$178	$173
Deferred natural gas costs	33	25	38
Elizabethtown Gas derivative financial instruments	29	23	-
Deferred seasonal rates	22	-	22
Regulatory tax liability	18	19	20
Unamortized investment tax credit	14	14	15
Other	19	22	20
Total regulatory liabilities	329	281	288
Associated liabilities			
PRP costs	169	189	231
ERC	95	96	95
Elizabethtown Gas derivative financial instruments	-	-	16
Total associated liabilities	264	285	342
Total regulatory and associated liabilities	$593	$566	$630

There have been no significant changes to our regulatory assets and liabilities as described in Note 1 to our Consolidated Financial Statements in Item 8 of our Annual Report on Form 10-K for the year ended December 31, 2008.

Income Taxes

As a result of our adoption of SFAS 160, income tax expense and our effective tax rate are determined from earnings before income tax less net income attributable to the noncontrolling interest. For more information on our adoption of SFAS 160, see Note 5.

There have been no significant changes to our income taxes as described in Note 8 to our Consolidated Financial Statements in Item 8 of our Annual Report on Form 10-K for the year ended December 31, 2008.

Earnings per Common Share

We compute basic earnings per common share by dividing our net income attributable to our common shareholders by the daily weighted-average number of common shares outstanding. Diluted earnings per common share reflect the potential reduction in earnings per common share that could occur when potentially dilutive common shares are added to common shares outstanding. We adopted FSP EITF 03-6-1 on January 1, 2009, which provides guidance on the computation of earnings per share when a company has unvested share awards outstanding that have the nonforfeitable right to receive dividends. The effects of this FSP were immaterial to our calculation of earnings per share.

We derive our potentially dilutive common shares by calculating the number of shares issuable under restricted stock, restricted stock units and stock options. The future issuance of shares underlying the restricted stock and restricted share 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. The following table shows the calculation of our diluted shares, for the periods presented, assuming restricted stock and restricted stock units currently awarded under the plan ultimately vest and stock options currently exercisable at prices below the average market prices are exercised.

	Three months ended March 31,	
In millions	2009	2008
Denominator for basic earnings per share (1)	76.7	76.0
Assumed exercise of restricted stock, restricted stock units and stock options	0.1	0.3
Denominator for diluted earnings per share	76.8	76.3

(1) Daily weighted-average shares outstanding.

The following table contains the weighted average shares attributable to outstanding stock options that were excluded from the computation of diluted earnings per share because their effect would have been anti-dilutive, as the exercise prices were greater than the average market price:

	March 31,	
In millions	2009	2008
Three months ended	2.2	1.6

The increase of 0.6 million shares which were excluded from the computation of diluted earnings per share and considered anti-dilutive was a result of a decline in the average market value of our common shares at March 31, 2009 as compared to March 31, 2008.

Note 2 - Fair Value Measurements

The carrying value of cash and cash equivalents, receivables, accounts payable, short-term debt, other current liabilities, derivative financial instrument assets, derivative financial instrument liabilities and accrued interest approximate fair value. The following table shows the carrying amounts and fair values of our long-term debt including any current portions included in our condensed consolidated statements of financial position.

In millions	Carrying amount	Estimated fair value
As of March 31, 2009	$1,676	$1,633
As of December 31, 2008	1,676	1,647
As of March 31, 2008 (1)	1,678	1,734

(1) Includes $161 million of gas facility revenue bonds which we repurchased with proceeds from our commercial paper program in March and April 2008.

We estimate the fair value of our long-term debt using a discounted cash flow technique that incorporates a market interest yield curve with adjustments for duration, optionality and risk profile. In determining the market interest yield curve, we considered our currently assigned ratings for unsecured debt of BBB+ by S&P, Baa1 by Moody's and A- by Fitch.

SFAS 157 was effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. In December 2007, the FASB provided a one-year deferral of SFAS 157 for nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value on a recurring basis, at least annually. We adopted SFAS 157 on January 1, 2008, for our financial assets and liabilities, which primarily consist of derivatives we record in accordance with SFAS 133. We adopted SFAS 157 for our nonfinancial assets and liabilities on January 1, 2009, which had no impact to our condensed consolidated results of operations, cash flows and financial condition.

As defined in SFAS 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We utilize market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. We primarily apply the market approach for recurring fair value measurements and endeavor to utilize the best available information. Accordingly, we use valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. We are able to classify fair value balances based on the observance of those inputs. SFAS 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1) and the lowest priority to unobservable inputs (level 3).

The following table sets forth, by level within the fair value hierarchy, our financial assets and liabilities that were accounted for at fair value on a recurring basis as of March 31, 2009. As required by SFAS 157, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

Our exchange-traded derivative contracts, which include futures and exchange-traded options, are generally based on unadjusted quoted prices in active markets and are classified within level 1. Some exchange-traded derivatives are valued using broker or dealer quotation services, or market transactions in either the listed or OTC markets, which are classified within level 2.

The determination of the fair values in the following table incorporates various factors required under SFAS 157. These factors include not only the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits, letters of credit and priority interests), but also the effect of our nonperformance risk on our liabilities. For more information on our derivative financial instruments, see Note 3.

In millions	March 31, 2009 Assets	March 31, 2009 Liabilities	December 31, 2008 Assets (1)	December 31, 2008 Liabilities	March 31, 2008 Assets	March 31, 2008 Liabilities
	Recurring fair values Commodity derivative financial instruments					
Quoted prices in active markets (Level 1)	$39	$(198)	$52	$(117)	$28	$(34)
Significant other observable inputs (Level 2)	163	(19)	154	(28)	39	(44)
Netting of cash collateral	48	166	35	89	-	36
Total carrying value (2)	**$250**	**$(51)**	**$241**	**$(56)**	**$67**	**$(42)**

(1) $4 million premium associated with weather derivatives has been excluded as they are based on intrinsic value, not fair value. For more information see Note 3.

(2) There were no significant unobservable inputs (level 3) for any of the periods presented.

Note 3 - Derivative Financial Instruments

Netting of Cash Collateral with Derivative Assets and Liabilities under Master Netting Arrangements

We maintain accounts with exchange brokers to facilitate financial derivative transactions in support of our energy marketing and risk management activities. Based on the value of our positions in these accounts and the associated margin requirements, we may be required to deposit cash into these broker accounts. We are required to offset this cash collateral with the associated fair value of the derivative financial instruments. Our cash collateral amounts are provided in the following table.

In millions	Mar. 31, 2009	As of Dec. 31, 2008	Mar. 31, 2008
Right to reclaim cash collateral	$214	$128	$37
Obligations to return cash collateral	-	(4)	(1)
Total cash collateral	$214	$124	$36

Derivative Financial Instruments

Our use of derivative financial instruments and physical transactions is limited to predefined risk tolerances associated with pre-existing or anticipated physical natural gas sales and purchases and system use and storage. We use the following derivative financial instruments and physical transactions to manage commodity price, interest rate, weather, automobile fuel price and foreign currency risks:

- forward contracts
- futures contracts
- options contracts
- financial swaps
- treasury locks
- weather derivative contracts
- storage and transportation capacity transactions
- foreign currency forward contracts

Our derivative financial instruments do not contain any material credit-risk-related or other contingent features that could cause us to make accelerated payments over and above collateral we post in the normal course of business when our financial instruments are in net liability positions. For information on our energy marketing receivables and payables, which do have credit-risk-related or other contingent features refer to Note 1. Our risk management activities are monitored by our Risk Management Committee (RMC), which consists of members of senior management. The RMC is charged with reviewing and enforcing our risk management activities and policies.

We adopted SFAS 161 on January 1, 2009, which amends the disclosure requirements of SFAS 133 and requires specific disclosures regarding how and why we use derivative instruments; the accounting for derivative instruments and related hedged items; and how derivative instruments and related hedged items affect our financial position, results of operations and cash flows. As SFAS 161 only requires additional disclosures concerning derivatives and hedging activities, this standard did not have an impact on our financial position, results of operations or cash flows.

We adopted FSP FAS 133-1 on January 1, 2009. This FSP requires more detailed disclosures about credit derivatives, including the potential adverse effects of changes in credit risk on the financial position, financial performance and cash flows of the sellers of the instruments. This FSP had no financial impact to our results of operations, cash flows or financial condition.

Interest Rate Derivative Financial Instruments

To maintain an effective capital structure, our policy is to borrow funds using a mix of fixed-rate and variable-rate debt. We have previously entered into interest rate swap agreements for the purpose of managing the appropriate mix of risk associated with our fixed-rate and variable-rate debt obligations. We designated these interest rate swaps as fair value hedges in accordance with SFAS 133 and recorded 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 interest rate risk being hedged. As of March 31, 2009, December 31, 2008 and March 31, 2008, we did not have any interest rate swap agreements.

Commodity Derivative Financial Instruments

All activities associated with commodity price risk management activities and derivative instruments are included as a component of cash flows from operating activities in our condensed consolidated statements of cash flows. Our derivatives not designated as hedges under SFAS 133, are included within operating cash flows as a source (use) of cash totaling $(10) million in 2009 and $36 million in 2008.

Distribution Operations In accordance with a directive from the New Jersey Commission, Elizabethtown Gas enters into derivative financial instruments to hedge the impact of market fluctuations in natural gas prices. Pursuant to SFAS 133, such derivative transactions are accounted for at fair value each reporting period in our condensed consolidated statements of financial position. In accordance with regulatory requirements realized gains and losses related to these derivatives are reflected in natural gas costs and ultimately included in billings to customers. However, these derivative financial instruments are not designated as hedges in accordance with SFAS 133. For more information on our regulatory assets and liabilities see Note 1.

Retail Energy Operations SouthStar uses commodity-related derivative financial instruments (futures, options and swaps) to manage exposures arising from changing commodity prices. SouthStar's objective for holding these derivatives is to utilize the most effective method to reduce or eliminate the impact of this exposure. We have designated a portion of SouthStar's derivative transactions, consisting of financial swaps to manage the commodity risk associated with forecasted purchases and sales of natural gas, as cash flow hedges under SFAS 133. We record derivative gains or losses arising from cash flow hedges in OCI and reclassify them into earnings in the same period as the settlement of the underlying hedged item. SouthStar currently has minimal hedge ineffectiveness defined as when the gains or losses on the hedging instrument do not offset and are greater than the losses or gains on the hedged item. This cash flow hedge ineffectiveness is recorded in cost of gas in our condensed consolidated statements of income in the period in which it occurs. We have not designated the remainder of SouthStar's derivative instruments as hedges under SFAS 133 and, accordingly, we record changes in their fair value within cost of gas in our condensed consolidated statements of income in the period of change. For more information on SouthStar's gains and losses reported within comprehensive income that affects equity, see our condensed consolidated statements of comprehensive income. SouthStar has hedged its exposures to commodity risk to varying degrees in the markets in which it serves retail, commercial and industrial customers. Approximately 80% of SouthStar's purchase instruments and 56% of its sales instruments are scheduled to mature in 2009 and the remaining 20% and 44%, respectively, in less than 2 years.

SouthStar also enters into both exchange and OTC derivative transactions to hedge commodity price risk. Credit risk is mitigated for exchange transactions through the backing of the NYMEX member firms. For OTC transactions, SouthStar utilizes master netting arrangements to reduce overall credit risk. As of March 31, 2009, SouthStar's maximum exposure to any single OTC counterparty was $6 million.

Wholesale Services Sequent uses derivative financial instruments to reduce our exposure to the risk of changes in the prices of natural gas. The fair value of these derivative financial instruments reflects the estimated amounts that we would receive or pay to terminate or close the contracts at the reporting date, taking into account the current unrealized gains or losses on open contracts. We use external market quotes and indices to value substantially all the derivative financial instruments we use.

We mitigate substantially all the commodity price risk associated with Sequent's natural gas portfolio by locking in the economic margin at the time we enter into natural gas purchase transactions for our stored natural gas. We purchase natural gas for storage when the difference in the current market price we pay to buy and transport natural gas plus the cost to store the natural gas is less than the market price we can receive in the future, resulting in a positive net operating margin. We use NYMEX futures contracts and other OTC derivatives to sell natural gas at that future price to substantially lock in the operating margin we will ultimately realize when the stored natural gas is actually sold. These futures contracts meet the definition of derivatives under SFAS 133 and are accounted for at fair value in our condensed consolidated statements of financial position, with changes in fair value recorded in our condensed consolidated statements of income in the period of change. However, these futures contracts are not designated as hedges in accordance with SFAS 133.

The purchase, transportation, storage and sale of natural gas are accounted for on a weighted average cost or accrual basis, as appropriate rather than on the fair value basis we utilize for the derivatives used to mitigate the commodity price risk associated with our storage portfolio. This difference in accounting can result in volatility in our reported earnings, even though the economic margin is essentially unchanged from the date the transactions were consummated. Approximately 95% of Sequent's purchase instruments and 96% of its sales instruments are scheduled to mature in less than 2 years and the remaining 5% and 4%, respectively, in 3 to 9 years.

The changes in fair value of Sequent's derivative instruments utilized in its energy marketing and risk management activities and contract settlements decreased the net fair value of its contracts outstanding by $75 million during both the three months ended March 31, 2009 and the three months ended March 31, 2008.

Weather Derivative Financial Instruments

In 2009 and 2008, SouthStar entered into weather derivative contracts as economic hedges of operating margins in the event of warmer-than-normal and colder-than-normal weather in the heating season, primarily from November through March. SouthStar accounts for these contracts using the intrinsic value method under the guidelines of EITF 99-02, and accordingly these derivative financial instruments are not designated as derivatives or hedges under SFAS 133. SouthStar recorded a net payable for this hedging activity of less than $1 million at March 31, 2009 and at March 31, 2008 and a current asset of $4 million at December 31, 2008. In the three months ended March 31, 2009 and 2008, SouthStar recognized $4 million and $5 million of losses on its weather derivative financial instruments, which were reflected in cost of gas on our condensed consolidated statements of income.

Quantitative Disclosures Related to Derivative Financial Instruments

As of March 31, 2009, our derivative financial instruments were comprised of both long and short commodity positions, whereby a long position is a contract to purchase the commodity, and a short position is a contract to sell the commodity. As of March 31, 2009, we had net long commodity contracts outstanding in the following quantities:

	Commodity contracts (in Bcf)			
Hedge designation under SFAS 133	Distribution operations	Retail energy operations	Wholesale services	Consolidated
Cash flow	-	9	-	9
Not designated	11	13	199	223
Total	11	22	199	232

Derivative Financial Instruments on the Condensed Consolidated Statements of Income

The following table presents the gain or (loss) on derivative financial instruments in our condensed consolidated statements of income for the three months ended March 31, 2009.

	Three months ended March 31, 2009	
In millions	Retail energy operations	Wholesale services
Designated as cash flow hedges under SFAS 133		
Commodity contracts – loss reclassified from OCI into cost of gas for settlement of hedged item	$(4)	$-
Not designated as hedges under SFAS 133:		
Commodity contracts – fair value adjustments recorded in operating revenues (1)	-	20
Commodity contracts – fair value adjustments recorded in cost of gas (2)	(1)	-
Total gains (losses) on derivative financial instruments	$(5)	$20

(1) Associated with the fair value of existing derivative financial instruments at March 31, 2009.
(2) Excludes $4 million of losses recorded in cost of gas associated with weather derivatives accounted for in accordance with EITF 99-02.

In accordance with regulatory requirements, any realized gains and losses on derivative financial instruments used in our distribution operations segment are reflected in deferred natural gas costs within our condensed consolidated statements of financial position. In the three months ended March 31, 2009, Elizabethtown Gas recognized $13 million of losses on its derivative financial instruments and less than $1 million in gains for the same period in 2008.

The following amounts (pre-tax) represent the expected recognition in our condensed consolidated statements of income of the deferred losses recorded in OCI associated with retail energy operations' derivative financial instruments, based upon the fair values of these financial instruments as of March 31, 2009:

In millions	Retail energy operations
Designated as hedges under SFAS 133	
Commodity contracts – expected net loss reclassified from OCI into cost of gas for settlement of hedged item:	
Next twelve months	$(27)
Thereafter	-
Total	$(27)

Derivative Financial Instruments on the Statements of Financial Position

The following table presents the fair value and statements of financial position classification of our derivative financial instruments by operating segment as of March 31, 2009.

		As of March 31, 2009			
In millions	Statements of financial position location (1)	Distribution operations	Retail energy operations	Wholesale services	Consolidated (2)
Designated as cash flow hedges under SFAS 133:					
Asset Financial Instruments					
Current commodity contracts	Derivative financial instruments assets and liabilities – current portion	$-	$12	$-	$12
Noncurrent commodity contracts	Derivative financial instruments assets and liabilities	-	-		-
Liability Financial Instruments					
Current commodity contracts	Derivative financial instruments assets and liabilities – current portion	-	(32)	-	(32)
Noncurrent commodity contracts	Derivative financial instruments assets and liabilities	-	-	-	-
Total		-	(20)	-	(20)
Not designated as hedges under SFAS 133:					
Asset Financial Instruments					
Current commodity contracts	Derivative financial instruments assets and liabilities – current portion	23	3	520	546
Noncurrent commodity contracts	Derivative financial instruments assets and liabilities	6	-	85	91
Liability Financial Instruments					
Current commodity contracts	Derivative financial instruments assets and liabilities – current portion	(23)	(5)	(535)	(563)
Noncurrent commodity contracts	Derivative financial instruments assets and liabilities	(6)	-	(63)	(69)
Total		-	(2)	7	5
Total derivative financial instruments		$-	$(22)	$7	$(15)

(1) These amounts are netted within our condensed consolidated statements of financial position. Some of our derivative financial instruments have asset positions which are presented as a liability in our condensed consolidated statements of financial position, and we have derivative instruments that have liability positions which are presented as an asset in our condensed consolidated statements of financial position.

(2) As required by SFAS 161, the fair value amounts above are presented on a gross basis. Additionally, the amounts above do not include $214 million of cash collateral held on deposit in broker margin accounts as of March 31, 2009. As a result, the amounts above will differ from the amounts presented on our condensed consolidated statements of financial position, and the fair value information presented for our financial instruments in Note 2.

Note 4 - Employee Benefit Plans

FSP FAS 132(R)-1

This FSP requires additional disclosures relating to postretirement benefit plan assets to provide transparency regarding the types of assets and the associated risks within the types of plan assets. The required disclosures include:

- How investment allocation decisions are made, including information that provides an understanding of investment policies and strategies,
- The major categories of plan assets,
- Inputs and valuation techniques used to measure the fair value of plan assets, including those measurements using significant unobservable inputs, on changes in plan assets for the period, and
- Significant concentrations of risk within plan assets.

This FSP is effective for fiscal years ending after December 15, 2009 and requires additional disclosures in our notes to condensed consolidated financial statements, but will not have a material impact on our financial position, results of operations or cash flows.

Pension Benefits

We sponsor two tax-qualified defined benefit retirement plans for our eligible employees, the AGL Resources Inc. Retirement Plan and the Employees' Retirement Plan of NUI Corporation. A defined benefit plan specifies the amount of benefits an eligible participant eventually will receive using information about the participant. Following are the combined cost components of our two defined pension plans for the periods indicated.

	Three months ended March 31,	
In millions	2009	2008
Service cost	$2	$2
Interest cost	7	7
Expected return on plan assets	(7)	(8)
Amortization of prior service cost	(1)	(1)
Recognized actuarial loss	2	1
Net pension benefit cost	$3	$1

Our employees do not contribute to these retirement plans. We fund the plans by contributing at least the minimum amount required by applicable regulations and as recommended by our actuary. However, we may also contribute in excess of the minimum required amount. We calculate the minimum amount of funding using the projected unit credit cost method. The Pension Protection Act (the Act) of 2006 contained new funding requirements for single employer defined benefit pension plans. The Act establishes a 100% funding target for plan years beginning after December 31, 2007. However, a delayed effective date of 2011 may apply if the pension plan meets the following targets: 92% funded in 2008; 94% funded in 2009; and 96% funded in 2010. In December 2008, the Worker, Retiree and Employer Recovery Act of 2008 allowed us to measure our 2008 and 2009 funding target at 92%. During the first three months of 2009, we made a $14 million contribution to our qualified plans. We expect to make additional contributions to our pension plans of $18 million during the remainder of 2009. In 2008, we did not make a contribution, as one was not required for our pension plans.

Postretirement Benefits

The Health and Welfare Plan for Retirees and Inactive Employees of AGL Resources Inc. (AGL Postretirement Plan) covers all eligible AGL Resources employees who were employed as of September 30, 2002, if they reach retirement age while working for us. Eligibility for benefits under the AGL Postretirement Plan is based on age and years of service. The state regulatory commissions have approved phase-ins that defer a portion of other postretirement benefits expense for future recovery. Effective December 8, 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 was signed into law. This act 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. Medicare-eligible participants in the AGL Postretirement Plan receive prescription drug benefits through a Medicare Part D plan offered by a third party and to which we subsidize participant premiums. Medicare-eligible retirees who opt out of the AGL Postretirement Plan are eligible to receive a cash subsidy which may be used towards eligible prescription drug expenses.

Following are the cost components of the AGL Postretirement Plan for the periods indicated.

	Three months ended March 31,	
In millions	2009	2008
Service cost	$-	$-
Interest cost	1	1
Expected return on plan assets	(1)	(1)
Amortization of prior service cost	(1)	(1)
Recognized actuarial loss	1	-
Net postretirement benefit cost	$-	$(1)

Employee Savings Plan Benefits

We sponsor the Retirement Savings Plus Plan (RSP Plan), a defined contribution benefit plan that allows eligible participants to make contributions to their accounts up to specified limits. Under the RSP Plan, we made $2 million in matching contributions to participant accounts in the first three months of 2009 and $2 million in the same period last year.

Note 5 - Equity

Noncontrolling Interests

We currently own a noncontrolling 70% financial interest in SouthStar, a joint venture with Piedmont who owns the remaining 30%. Our 70% interest is noncontrolling because all significant management decisions require approval by both owners. Although our ownership interest in the SouthStar partnership is 70%, under an amended and restated joint venture agreement executed in March 2004, SouthStar's earnings are allocated 75% to us and 25% to Piedmont except for earnings related to customers in Ohio and Florida, which are allocated 70% to us and 30% to Piedmont.

We are the primary beneficiary of SouthStar’s activities and have determined that SouthStar is a variable interest entity as defined by FIN 46R which requires us to consolidate the variable interest entity. The assets, liabilities, and noncontrolling interests of a consolidated variable interest entity are accounted for in our condensed consolidated financial statements as if the entity were consolidated based on voting interests.

The Company determined that SouthStar was a variable interest entity because its equal voting rights with Piedmont are not proportional to its economic obligation to absorb 75% of any losses or residual returns from SouthStar, except those losses and returns related to customers in Ohio and Florida. In addition, SouthStar obtains substantially all its transportation capacity for delivery of natural gas through our wholly-owned subsidiary, Atlanta Gas Light.

On January 1, 2009, we adopted SFAS 160, and applied the presentation and disclosure requirements retrospectively for all periods presented. SFAS 160 does not change the requirements of FIN 46R and provides that the noncontrolling interest should be reported as a separate component of equity on our condensed consolidated statements of financial position. Additionally, prior to adoption of SFAS 160, we recorded our earnings allocated to Piedmont as a component of earnings before income taxes in our condensed consolidated statements of income. SFAS 160 requires that any net income attributable to the noncontrolling interest be presented separately in our condensed consolidated statements of income. As a result, net income from noncontrolling interest is reported after net income in order to report net income attributable to the parent and the noncontrolling interest. The adoption of SFAS 160 has no effect on our calculation of basic or diluted earnings per share amounts, which will continue to be based upon amounts attributable to AGL Resources.

The March 2004 amended and restated joint venture agreement includes a series of options granting us the evergreen opportunity to purchase all or a portion of Piedmont’s ownership interest in SouthStar. We have the right to exercise an option to purchase on or before November of each year, with the purchase being effective as of January 1, of the following year. We currently have two vested options to purchase a portion of Piedmont’s ownership interest (33 1/3% and 50%, respectively). Effective January 1, 2010, our option vests to purchase up to 100% of Piedmont’s ownership interest. If we were to exercise any option to purchase less than 100% of Piedmont’s ownership interest in SouthStar, Piedmont, at its discretion, could require us to purchase their entire ownership interest. The purchase price, in any exercise of our option, would be based on the then current fair market value of SouthStar. SFAS 160 requires that increases in our ownership interest are recorded as equity transactions, with no adjustment to the carrying amounts of the assets and liabilities. Piedmont has challenged our interpretation of the duration of the various options in the amended and restated agreement as described in Note 7.

Stock-Based Compensation

In the first three months of 2009, we issued grants of approximately 250,000 stock options and 211,000 restricted stock units, which will result in the recognition of approximately $2 million of stock-based compensation expense in 2009. No material share awards have been granted to employees whose compensation is subject to capitalization. We use the Black-Scholes pricing model to determine the fair value of the options granted. On an annual basis, we evaluate the assumptions and estimates used to calculate our stock-based compensation expense.

There have been no significant changes to our stock-based compensation, as described in Note 4 to our Consolidated Financial Statements in Item 8 of our Annual Report on Form 10-K for the year ended December 31, 2008.

Comprehensive Income

Our comprehensive income includes net income plus OCI, which includes other gains and losses affecting equity that GAAP excludes from net income. Such items consist primarily of gains and losses on certain derivatives designated as cash flow hedges and unfunded or overfunded pension and postretirement obligation adjustments.

Note 6 - Debt

Our issuance of various securities, including long-term and short-term debt, is subject to customary approval or authorization by, or filings with, state and federal regulatory bodies, including state public service commissions, the SEC and the FERC pursuant to the Energy Policy Act of 2005. The following table provides more information on our various debt securities. For more information on our debt, see Note 6 in Item 8 of our Annual Report on Form 10-K for the year ended December 31, 2008.

In millions	Year(s) due	Interest rate (1)	Weighted average interest rate(2)	Outstanding as of Mar. 31, 2009	Dec. 31, 2008	Mar.31, 2008
Short-term debt						
Commercial paper & Credit Facilities	2009	0.9%	1.2%	$335	$773	$213
SouthStar line of credit	2009	1.1	1.1	45	75	-
Sequent lines of credit	2009	0.9	0.9	22	17	31
Pivotal Utility line of credit	-	-	-	-	-	10
Current portion of long-term debt	-	-	-	-	-	114
Capital leases	2009	4.9	4.9	1	1	1
Total short-term debt		**1.0%**	**1.1%**	**$403**	**$866**	**$369**
Long-term debt - net of current portion						
Senior notes	2011-2034	4.5-7.1%	5.9%	$1,275	$1,275	$1,275
Gas facility revenue bonds	2022-2033	0.2-5.3	1.3	200	200	40
Medium-term notes	2012-2027	6.6-9.1	7.8	196	196	196
Capital leases	2013	4.9	4.9	4	4	5
Total long-term debt		**5.5%**	**5.5%**	**$1,675**	**$1,675**	**$1,516**
Total debt		**4.6%**	**4.3%**	**$2,078**	**$2,541**	**$1,885**

(1) As of March 31, 2009

(2) For the three months ended March 31, 2009.

Note 7 - Commitments and Contingencies

Contractual Obligations and Commitments

We have incurred various contractual obligations and financial commitments in the normal course of our operating and financing activities that are reasonably likely to have a material effect on liquidity or the availability of capital resources. Contractual obligations include future cash payments required under existing contractual arrangements, such as debt and lease agreements. These obligations may result from both general financing activities and from commercial arrangements that are directly supported by related revenue-producing activities. As we do for other subsidiaries, we provide guarantees to certain gas suppliers for SouthStar in support of payment obligations. There were no significant changes to our contractual obligations described in Note 7 to our Consolidated Financial Statements in Item 8 of our Annual Report on Form 10-K for the year ended December 31, 2008.

Contingent financial commitments, such as financial guarantees, represent obligations that become payable only if certain predefined events occur and include the nature of the guarantee and the maximum potential amount of future payments that could be required of us as the guarantor. The following table illustrates our contingent financial commitments as of March 31, 2009.

In millions	Total	Commitments due before Dec. 31, 2009	2010 & thereafter
Standby letters of credit and performance and surety bonds	$51	$45	$6

Litigation

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

Information on the Jefferson Island Storage & Hub, LLC vs. State of Louisiana litigation is described in Note 7 to our Consolidated Financial Statements in Item 8 of our Annual Report on Form 10-K for the year ended December 31, 2008. In April 2009, the trial court ruled that the legislation that restricted Jefferson Island’s ability to use water from the Chicot aquifer to expand its existing storage facility is unconstitutional and invalid. In addition, the court scheduled a trial in September 2009 on Jefferson Island’s claim that it is authorized to expand the facility under its mineral lease. The ultimate resolution of such litigation cannot be determined, but it is not expected to have a material adverse effect on our condensed consolidated financial position, results of operations or cash flows.

In March 2009, Piedmont filed a lawsuit in the Court of Chancery of the State of Delaware against GNGC asking the court to enter a judgment declaring that GNGC's right to purchase Piedmont's ownership interest in SouthStar expires on November 1, 2009. We believe that, under the March 2004 amended and restated joint venture agreement GNGC has the evergreen opportunity, throughout the term of the joint venture, to exercise its options to purchase a portion of, or all of, Piedmont's interest in SouthStar by notifying Piedmont on or before November of each year with the purchase being effective as of January 1 of the following year. The ultimate resolution of this litigation cannot be determined, but we believe that the dispute will be resolved before our next option exercise notification date on November 1, 2009.

In February 2008, the consumer affairs staff of the Georgia Commission alleged that GNG charged its customers on variable rate plans prices for natural gas that were in excess of the published price, that it failed to give proper notice regarding the availability of potentially lower price plans and that it changed its methodology for computing variable rates. GNG asserted that it fully complied with all applicable rules and regulations, that it properly charged its customers on variable rate plans the rates on file with the Georgia Commission, and that, consistent with its terms and conditions of service, it routinely switched customers who requested to move to another price plan for which they qualified. In order to resolve this matter GNG agreed to pay $2.5 million in the form of credits to customers, or as directed by the Georgia Commission, which was recorded in our statements of consolidated income for the year ended December 31, 2008.

In February 2008, a class action lawsuit was filed in the Superior Court of Fulton County in the State of Georgia against GNG containing similar allegations to those asserted by the Georgia Commission staff and seeking damages on behalf of a class of GNG customers. This lawsuit was dismissed in September 2008. In October 2008, the plaintiffs appealed the dismissal of the lawsuit and the Georgia Court of Appeals heard oral arguments in 2009. GNG is awaiting the Georgia Court of Appeal's ruling on the lawsuit.

In March 2008, a second class action suit was filed against GNG in the State Court of Fulton County in the State of Georgia, regarding monthly service charges. This lawsuit alleges that GNG arbitrarily assigned customer service charges rather than basing each customer service charge on a specific credit score. GNG asserts that no violation of law or Georgia Commission rules has occurred, that this lawsuit is without merit and has filed motions to dismiss this class action suit on various grounds. This lawsuit was dismissed with prejudice in March 2009. In April 2009, plaintiffs appealed the dismissal of the lawsuit.

Review of Compliance with FERC Regulations

In 2008 we conducted an internal review of our compliance with FERC interstate natural gas pipeline capacity release rules and regulations. Independent of our internal review, we also received data requests from FERC's Office of Enforcement relating specifically to compliance with FERC's capacity release posting and bidding requirements. We have responded to FERC's data requests and are fully cooperating with FERC in its investigation. As a result of this process, we have identified certain instances of possible non-compliance. We are committed to full regulatory compliance and we have met and continue to meet with the FERC Enforcement staff to discuss with them these instances of possible non-compliance. Accordingly we have accrued an appropriate estimate of possible penalties assessed by the FERC. While we continue to adjust this estimate as more information becomes available, the estimate does not have, and management does not believe the ultimate resolution will have, a material financial impact to our condensed consolidated results of operations, cash flows or financial position.

Note 8 - Segment Information

We are an energy services holding company whose principal business is the distribution of natural gas in six states - Florida, Georgia, Maryland, New Jersey, Tennessee and Virginia. We generate nearly all our operating revenues through the sale, distribution, transportation and storage of natural gas. We are involved in several related and complementary businesses, including retail natural gas marketing to end-use customers primarily in Georgia; natural gas asset management and related logistics activities for each of our utilities as well as for nonaffiliated companies; natural gas storage arbitrage and related activities; and the development and operation of high-deliverability natural gas storage assets. We manage these businesses through four operating segments – distribution operations, retail energy operations, wholesale services and energy investments and a nonoperating corporate segment which includes intercompany eliminations.

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

You should not consider EBIT an alternative to, or a more meaningful indicator of our operating performance than, operating income or net income attributable to AGL Resources Inc. as determined in accordance with GAAP. In addition, our EBIT may not be comparable to a similarly titled measure of another company. The following table contains the reconciliations of EBIT to operating income, earnings before income taxes and net income attributable to AGL Resources Inc. for the three months ended March 31, 2009 and 2008.

	Three months ended March 31,	
In millions	2009	2008
Operating revenues	$995	$1,012
Operating expenses	765	824
Operating income	230	188
Other income	2	1
EBIT	232	189
Interest expense, net	(25)	(30)
Earnings before income taxes	207	159
Income tax expense	72	54
Net income	135	105
Net income attributable to the noncontrolling interest	16	16
Net income attributable to AGL Resources Inc.	$119	$89

Statements of financial position information at December 31, 2008, is as follows:

In millions	Identifiable and total assets (1)	Goodwill
Distribution operations	$5,138	$404
Retail energy operations	315	-
Wholesale services	970	-
Energy investments	353	14
Corporate and intercompany eliminations (2)	(66)	-
Consolidated AGL Resources Inc.	$6,710	$418

(1) Identifiable assets are those assets used in each segment's operations.

(2) Our corporate segment's assets consist primarily of cash and cash equivalents and property, plant and equipment and reflect the effect of intercompany eliminations.

Summarized income statement information, identifiable and total assets, goodwill and property, plant and equipment expenditures as of and for the three months ended March 31, 2009 and 2008, by segment, are shown in the following tables.

Three months ended March 31, 2009

In millions	Distribution operations	Retail energy operations	Wholesale services	Energy investments	Corporate and intercompany eliminations (3)	Consolidated AGL Resources
Operating revenues from external parties	$572	$343	$68	$10	$2	$995
Intercompany revenues (1)	35	-	-	-	(35)	-
Total operating revenues	607	343	68	10	(33)	995
Operating expenses						
Cost of gas	355	259	9	-	(34)	589
Operation and maintenance	83	20	19	5	(2)	125
Depreciation and amortization	32	1	1	2	3	39
Taxes other than income taxes	9	-	1	1	1	12
Total operating expenses	479	280	30	8	(32)	765
Operating income (loss)	128	63	38	2	(1)	230
Other income	2	-	-	-	-	2
EBIT	$130	$63	$38	$2	$(1)	$232
Identifiable and total assets (2)	$5,095	$261	$653	$373	$(225)	$6,157
Goodwill	$404	$-	$-	$14	$-	$418
Capital expenditures for property, plant and equipment	$69	$-	$-	$23	$5	$97

Three months ended March 31, 2008

In millions	Distribution operations	Retail energy operations	Wholesale services	Energy investments	Corporate and intercompany eliminations (3)	Consolidated AGL Resources
Operating revenues from external parties	$610	$375	$17	$11	$(1)	$1,012
Intercompany revenues (1)	66	-	-	-	(66)	-
Total operating revenues	676	375	17	11	(67)	1,012
Operating expenses						
Cost of gas	428	293	2	-	(66)	657
Operation and maintenance	86	19	12	4	(2)	119
Depreciation and amortization	31	1	1	1	2	36
Taxes other than income taxes	9	-	1	1	1	12
Total operating expenses	554	313	16	6	(65)	824
Operating income (loss)	122	62	1	5	(2)	188
Other income	1	-	-	-	-	1
EBIT	$123	$62	$1	$5	$(2)	$189
Identifiable and total assets (2)	$4,769	$296	$968	$287	$(214)	$6,106
Goodwill	$406	$-	$-	$14	$-	$420
Capital expenditures for property, plant and equipment	$59	$6	$-	$11	$4	$80

(1) Intercompany revenues – Wholesale services records its energy marketing and risk management revenue on a net basis. Wholesale services' total operating revenues include intercompany revenues of $165 million and $273 million for the three months ended March 31, 2009 and 2008, respectively.
(2) Identifiable assets are those used in each segment's operations.
(3) Our corporate segment's assets consist primarily of cash and cash equivalents, property, plant and equipment and reflect the effect of intercompany eliminations.

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

FORWARD-LOOKING STATEMENTS

Certain expectations and projections regarding our future performance referenced in this Management's Discussion and Analysis of Financial Condition and Results of Operations section and elsewhere in this report, as well as in other reports and proxy statements we file with the SEC or otherwise release to the public and on our website are forward-looking statements. Senior officers and other employees may also make verbal statements to analysts, investors, regulators, the media and others that are forward-looking.

Forward-looking statements involve matters that are not historical facts, and because these statements involve anticipated events or conditions, forward-looking statements often include words such as "anticipate," "assume," "believe," "can," "could," "estimate," "expect," "forecast," "future," "goal," "indicate," "intend," "may," "outlook," "plan," "potential," "predict," "project," "seek," "should," "target," "would," or similar expressions. You are cautioned not to place undue reliance on our forward-looking statements. Our expectations are not guarantees and are based on currently available competitive, financial and economic data along with our operating plans. While we believe that our expectations are reasonable in view of currently available information, our expectations are subject to future events, risks and uncertainties, and there are several factors - many beyond our control - that could cause our results to differ significantly from our expectations.

Such events, risks and uncertainties include, but are not limited to, changes in price, supply and demand for natural gas and related products; the impact of changes in state and federal legislation and regulation including any changes related to climate change; actions taken by government agencies on rates and other matters; concentration of credit risk; utility and energy industry consolidation; the impact on cost and timeliness of construction projects by government and other approvals, development project delays, adequacy of supply of diversified vendors, unexpected change in project costs, including the cost of funds to finance these projects; the impact of acquisitions and divestitures; direct or indirect effects on our business, financial condition or liquidity resulting from a change in our credit ratings or the credit ratings of our counterparties or competitors; interest rate fluctuations; financial market conditions, including recent disruptions in the capital markets and lending environment and the current economic downturn; and general economic conditions; uncertainties about environmental issues and the related impact of such issues; the impact of changes in weather, including climate change, on the temperature-sensitive portions of our business; the impact of natural disasters such as hurricanes on the supply and price of natural gas; acts of war or terrorism; and other factors described in detail in our filings with the SEC.

We caution readers that, in addition to the important factors described elsewhere in this report, the factors set forth in Item 1A, Risk Factors of our Annual Report on Form 10-K for the year ended December 31, 2008, among others, could cause our business, results of operations or financial condition in 2009 and thereafter to differ significantly from those expressed in any forward-looking statements. There also may be other factors that we cannot anticipate or that are not described in our Form 10-K or in this report that could cause results to differ significantly from our expectations.

Forward-looking statements are only as of the date they are made. We do not update these statements to reflect subsequent circumstances or events.

Overview

We are an energy services holding company whose principal business is the distribution of natural gas through our regulated natural gas distribution business and the sale of natural gas to end-use customers primarily in Georgia through our retail natural gas marketing business. For the three months ended March 31, 2009, our six utilities serve approximately 2.3 million end-use customers, making us the largest distributor of natural gas in the southeastern and mid-Atlantic regions of the United States based on customer count. Although our retail natural gas marketing business is not subject to the same regulatory framework as our utilities, it is an integral part of the framework for providing natural gas service to end-use customers in Georgia.

We also engage in natural gas asset management and related logistics activities for our own utilities as well as for non-affiliated companies; natural gas storage arbitrage and related activities; and the development and operation of high-deliverability underground natural gas storage assets. These businesses allow us to be opportunistic in capturing incremental value at the wholesale level, provide us with deepened business insight about natural gas market dynamics and facilitate our ability, in the case of asset management, to provide transparency to regulators as to how that value can be captured to benefit our utility customers through profit-sharing arrangements. Given the volatile and changing nature of the natural gas resource base in North America and globally, we believe that participation in these related businesses strengthens our company. We manage these businesses through four operating segments - distribution operations, retail energy operations, wholesale services, energy investments and a non-operating corporate segment.

Executive Summary

We intend to continue executing our plan for long-term earnings and dividend growth. Central to that plan is the execution of our regulatory strategy through the filing of rate cases to recover the investments we have made, and should continue to make, to enhance our infrastructure and improve customer service. Further, we are collaborating with regulatory agencies and other companies to promote and encourage conservation through innovative rate design mechanisms that we believe are positioning our utility businesses to benefit in an economic recovery.

We continue to explore select opportunities to expand our businesses in strategic areas and maintain a disciplined approach around current capital projects. Our major capital projects - our Golden Triangle Storage natural gas storage facility project and our Hampton Roads Crossing and Magnolia pipeline connection projects - are on schedule and within budget. In these challenging economic conditions we continue to aggressively focus on capital discipline and cost control, while moving ahead with projects and initiatives that we expect to have current and future benefits and provide an appropriate return on capital.

Distribution Operations

Our distribution operations segment is the largest component of our business and includes six natural gas local distribution utilities. These utilities construct, manage and maintain intrastate natural gas pipelines and distribution facilities and include:

- Atlanta Gas Light in Georgia
- Chattanooga Gas in Tennessee
- Elizabethtown Gas in New Jersey
- Elkton Gas in Maryland
- Florida City Gas in Florida
- Virginia Natural Gas in Virginia

Each utility operates subject to regulations of the state regulatory agencies in its service territories 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 generally should allow us to recover all prudently incurred costs, including a return on rate base sufficient to pay interest on debt and provide a reasonable return for our shareholders. Rate base generally consists of the original cost of utility plant in service, working capital and certain other assets; less accumulated depreciation on utility plant in service and net deferred income tax liabilities, and may include certain other additions or deductions.

Customer growth declined slightly in our distribution operations segment in the first three months of 2009 relative to last year, a trend we expect to continue through 2009. For the three months ended March 31, 2009, our year-over-year consolidated utility customer growth rate was slightly negative or (0.1)%, compared to 0.3% for the same period of 2008. We anticipate overall customer growth in 2009 to be flat to negative, primarily as a result of much slower growth in the residential housing markets throughout most of our service territories and the effects of a weak economy on our commercial and industrial customers. Over the last 3 years we have reduced our customer attrition rates. As a result, we believe we should be well positioned when the economy recovers.

The weak economy also impacted a significantly larger portion of consumer household incomes during the most recent winter heating season. As a result, we incurred additional bad debt expense and increased customer conservation. We expect these factors may continue to adversely impact our results of operations during the current economic situation. However, we expect operational and collections efforts combined with regulatory mechanisms in place in most of our jurisdictions to help mitigate some of our exposure to these factors.

The risks of increased bad debt expense and decreased operating margins from conservation are minimized at our largest utility, Atlanta Gas Light, as a result of its straight-fixed variable rate structure. In addition, customers in Georgia buy their natural gas from Marketers rather than from Atlanta Gas Light. Our credit exposure at Atlanta Gas Light is primarily related to the provision of services to the Marketers, but that exposure is mitigated, because we obtain security support in an amount equal to a minimum of no less than two times a Marketer’s highest month’s estimated bill. At our other utilities, while customer conservation could adversely impact our operating margins, we utilize measures to collect delinquent accounts and continue to be rigorous in monitoring and mitigating the impact of these expenses. Due to the timing of usage and billing, the full effects of the most recent heating season will not be known until several months following the end of the heating season.

We worked with regulators and state agencies in each of our jurisdictions to educate customers about higher energy costs in advance of the winter heating season, in particular, to ensure that those customers qualified for the Low Income Home Energy Assistance Program and other similar programs receive any needed assistance and we expect to continue this focus for the foreseeable future.

Upcoming rate cases In 2009 and 2010, we expect to file base rate cases in four of our six jurisdictions. Over the past several years our utilities have been fulfilling their long-term commitments to rate freezes, which begin expiring in 2009. As these rate cases are filed, we plan to seek rate reforms that encourage conservation and “decoupling.” In traditional rate designs, our utilities’ recovery of a significant portion of their fixed customer service costs is tied to assumed natural gas volumes used by our customers. We believe separating, or decoupling, the recovery of these fixed costs from the natural gas deliveries will align the interests of our customers and utilities by encouraging energy conservation, achieving rate stability for our customers and ensuring stable returns for our shareholders. These rate case filings are required due to settlements we reached with the applicable state authority in previous rate case or acquisition proceedings. The expected filing dates and dates for which current rates are expected to be effective are outlined in the chart below:

Company	Expected filing date	Current rates effective until
Atlanta Gas Light	Q4 2009	Q2 2010
Virginia Natural Gas	Q2 2010	Q3 2011
Chattanooga Gas	Q2 2010	Q1 2011

Elizabethtown Gas After a 5-year rate freeze and in accordance with the New Jersey Commission’s order, we filed a rate case in March 2009 with a proposed effective date of January 1, 2010. We are requesting an annual increase to base rates of $25 million. This filing included energy conservation programs and a proposed Efficiency Usage and Adjustment mechanism (EUA), which is a form of decoupling. If the EUA is approved, the current weather normalization clause would be eliminated. Our requested increase consists of:

- increased carrying costs and depreciation expense associated with increased rate base ($15 million)
- increased operating expenses, including higher bad debt expenses and other ($6 million)
- increased return on equity from 10% to 11.25% and return on rate base from 7.95% to 8.57% ($4 million)

In January 2009, and in response to New Jersey Governor Corzine’s call for utilities to assist in the economic recovery by increasing infrastructure investments, Elizabethtown Gas proposed an accelerated $60 million enhanced infrastructure program over the next two years. In April 2009, the New Jersey Commission approved a stipulation between Elizabethtown Gas and certain intervenors to the case. Under the stipulation, the infrastructure program should begin in 2009 and end in 2011, unless extended by the New Jersey Commission. A regulatory cost recovery mechanism will be established with estimated rates put into effect at the beginning of each year. At the end of the program the regulatory cost recovery mechanism will be trued-up and any remaining costs not previously collected will be included in base rates.

Atlanta Gas Light In March 2009 the Georgia Commission approved a new economic development and environmental program developed by Atlanta Gas Light to encourage smart new investment in Georgia. The new program, Georgia Sustainable Environmental Economic Development (Georgia SEED), is designed to attract and retain jobs, support projects to reduce carbon emissions and encourage new investment in Georgia.

Under Georgia SEED, Atlanta Gas Light will contract with new and existing business customers that may be considering expanding into Georgia. Atlanta Gas Light will have the option to invest capital to help customers finance line extensions, new natural gas equipment and equipment installations. This is a five-year experimental program and offers three potential avenues for contracts:

- Providing customers with the benefit of a new utility service extension to plant sites;
- Offering financing for the purchase and installation of new higher-efficiency gas equipment, such as engines, boilers, fleet vehicles, refueling stations and gas-fired air conditioning equipment; and
- Discounting utility rates to help lower overall energy costs.

Retail Energy Operations

Our retail energy operations segment consists of SouthStar, a joint venture owned 70% by us and 30% by Piedmont. SouthStar markets natural gas and related services to retail customers on an unregulated basis, principally in Georgia, as well as to commercial and industrial customers in Alabama, Florida, Ohio, Tennessee, North Carolina and South Carolina. SouthStar is the largest marketer of natural gas in Georgia with an approximate 34% market share based on customer count.

Although our ownership interest in the SouthStar partnership is 70%, the majority of SouthStar's earnings in Georgia are allocated by contract 75% to us and 25% to Piedmont. SouthStar’s earnings related to customers in Ohio and Florida are allocated 70% to us and 30% to Piedmont. We record the earnings allocated to Piedmont as a noncontrolling interest in our condensed consolidated statements of income, and we record Piedmont’s portion of SouthStar’s capital as a noncontrolling interest in our condensed consolidated statements of financial position. The majority of SouthStar’s earnings allocated to us for the three months ended March 31, 2009, were at the 75% contractual rate.

Our amended and restated joint venture agreement with Piedmont includes a series of options granting us the evergreen opportunity to purchase all or a portion of Piedmont’s ownership interest in SouthStar. We have the right to exercise an option to purchase on or before November of each year, with the purchase being effective as of January 1, of the following year. We currently have options to purchase up to 50% of Piedmonts’ ownership interest. Effective November 1, 2009, the option allows us to purchase 100% of Piedmont's ownership interest. If we were to exercise any option to purchase less than 100% of Piedmont's ownership interest in SouthStar, Piedmont, at its discretion, could require us to purchase their entire ownership interest. The purchase price, in any exercise of our option, would be based on the then current fair market value of SouthStar. In March 2009, Piedmont filed a lawsuit against GNGC regarding GNGC's right to purchase Piedmont's interest in SouthStar. See Note 7 of the financial statements for additional information.

SouthStar's operations are sensitive to seasonal weather, natural gas prices, retail pricing plans and strategies, customer growth and consumption patterns similar to those affecting our utility operations. SouthStar's retail pricing strategies and use of various economic hedging strategies, such as futures, options, swaps, weather derivative instruments and other risk management tools, help to ensure retail customer costs are covered to mitigate the potential effect of these issues on its operations.

In the Georgia market, we have experienced and expect through 2009 that we will experience the negative impact to operating margins from increased competition and an increase in the number of customers shopping for lower retail natural gas prices. Further, the number of customers switching Marketers in the Georgia market has increased in part due to customers seeking the most competitive price plans.

SouthStar continues to use a variety of targeted marketing programs to attract new customers and to retain existing ones. These programs emphasize GNG as the Marketer of choice. Despite these efforts we have seen a 3% decline in average customer count at SouthStar for the three months ended March 31, 2009, as compared to the same period of 2008. We believe this decline reflects some of the same economic conditions that have affected our utility businesses as well as the more competitive retail pricing market for natural gas in Georgia.

SouthStar may also be affected by the conservation and bad debt trends, but its overall exposure is partially mitigated by the high credit quality of SouthStar's customer base, lower wholesale natural gas prices, disciplined collection practices and the unregulated pricing structure in Georgia.

SouthStar continues to expand its business in other states as well. We are currently focusing these efforts on Ohio and Florida, which are growing more rapidly than anticipated.

Wholesale Services

Our wholesale services segment consists primarily of Sequent, our subsidiary involved in asset management and optimization, storage, transportation, producer and peaking services and wholesale marketing. Sequent seeks asset optimization opportunities, which focus on capturing the value from idle or underutilized assets, typically by participating in transactions to take advantage of pricing differences between varying markets and time horizons within the natural gas supply, storage and transportation markets to generate earnings. These activities are generally referred to as arbitrage opportunities.

Sequent's profitability is driven by volatility in the natural gas marketplace. Volatility arises from a number of factors such as weather fluctuations or the change in supply of, or demand for, natural gas in different regions of the country. Sequent seeks to capture value from the price disparity across geographic locations and various time horizons (location and seasonal spreads). In doing so, Sequent also seeks to mitigate the risks associated with this volatility and protect its margin through a variety of risk management and economic hedging activities.

Sequent provides its customers with natural gas from the major producing regions and market hubs in the U.S. and Canada. Sequent acquires transportation and storage capacity to meet its delivery requirements and customer obligations in the marketplace. Sequent's customers benefit from its logistics expertise and ability to deliver natural gas at prices that are advantageous relative to other alternatives available to its customers.

During the third quarter of 2008, Sequent negotiated an agreement for 40,000 dekatherms per day of transportation capacity for a period of 25 years beginning in August 2009. This agreement was executed in April 2009, and as a result, we have included approximately $89 million of future demand payments associated with this capacity within our unrecorded contractual obligations and commitment disclosures. As with its other transportation capacity agreements, Sequent has and will identify opportunities to lock-in economic value associated with this capacity through the use of financial hedges. Since the duration of this agreement is significantly longer than the average duration of Sequent's portfolio, the hedging of the capacity has increased our exposure to hedge gains and losses as well as impacting Sequent's VaR. During the second half of 2008 we began executing hedging transactions related to this transportation capacity. As a result of changes in the fair value of these hedges, Sequent reported hedge gains of $19 million during the first quarter of 2009. There was no significant impact to VaR during the period.

Asset management transactions Sequent's asset management customers include affiliated utilities, nonaffiliated utilities, municipal utilities, power generators and large industrial customers. These customers, due to seasonal demand or levels of activity, may have contracts for transportation and storage capacity, which may exceed their actual requirements. Sequent enters into structured agreements with these customers, whereby Sequent, on behalf of the customer, optimizes the transportation and storage capacity during periods when customers do not use it for their own needs. Sequent may capture incremental operating margin through optimization, and either share margins with the customers or pay them a fixed amount.

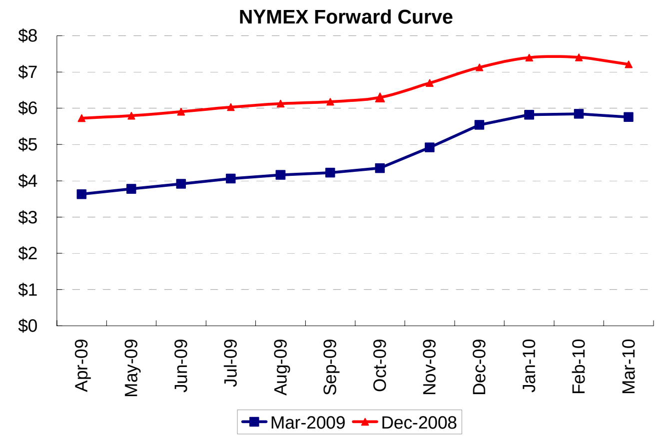
In 2009, Sequent extended its asset management agreement with Virginia Natural Gas for three additional years. The new agreement includes a tiered structure of profit sharing along with guaranteed annual minimums. With this renewal, Sequent has completed renewal of all its affiliated asset management contracts for multi-year periods.

The following table provides updated information on Sequent's asset management agreements with its affiliated utilities, including amended or extended agreements in 2008 and 2009 with Florida City Gas, Chattanooga Gas, Elizabethtown Gas and Virginia Natural Gas.

	Expiration date	% of shared profits or annual fee
Virginia Natural Gas	March 2012	(A) (B)
Chattanooga Gas	March 2011	50% (B)
Elizabethtown Gas	March 2011	(A) (B)
Atlanta Gas Light	March 2012	up to 60% (B)
Florida City Gas	March 2013	50%

(A) Shared on a tiered structure.
(B) Includes aggregate annual minimum payments of $14 million for Chattanooga Gas, Elizabethtown Gas, Virginia Natural Gas and Atlanta Gas Light.

Storage inventory outlook The following graph presents the NYMEX forward natural gas prices as of March 31, 2009 and December 31, 2008, for the period of April 2009 through March 2010, and reflects the prices at which Sequent could buy natural gas at the Henry Hub for delivery in the same time period. The Henry Hub is the largest centralized point for natural gas spot and futures trading in the United States. The 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.



During the last half of 2008 and continuing into 2009, natural gas prices declined significantly, reflecting the decline in the U.S. economy, increasing natural gas supplies and above-average storage volumes, among other factors. These lower gas prices expected for 2009, as reflected in the NYMEX forward curve, would result in significantly lower levels of working capital necessary for Sequent to purchase its natural gas inventories as compared to 2008, which saw significantly higher prices.

Sequent's expected natural gas withdrawals from physical salt dome and reservoir storage are presented in the following table along with the operating revenues expected at the time of withdrawal. Sequent's expected operating revenues are net of the estimated impact of regulatory sharing and reflect the amounts that are realizable in future periods based on the inventory withdrawal schedule and forward natural gas prices at March 31, 2009. Sequent's storage inventory is economically hedged with futures contracts, which results in an overall locked-in margin, timing notwithstanding.

	Withdrawal schedule (*in Bcf*)		
	Salt dome (WACOG $3.96)	**Reservoir** (WACOG $2.94)	**Expected operating revenues** (*in millions*)
2009			
Second quarter	-	1	$1
Third quarter	2	2	2
Fourth quarter	-	1	1
2010			
First quarter	-	1	1
Total	2	5	$5

If Sequent's storage withdrawals associated with existing inventory positions are executed as planned, it expects operating revenues from storage withdrawals of approximately $5 million during the next twelve months. This could change as Sequent adjusts its daily injection and withdrawal plans in response to changes in market conditions in future months and as forward NYMEX prices fluctuate. For more information on Sequent's energy marketing and risk management activities, see Item 3, Quantitative and Qualitative Disclosures About Market Risk - Commodity Price Risk.

Energy Investments

Our energy investments segment includes a number of businesses that are related or complementary to our primary business. The most significant of these businesses is our natural gas storage business, Jefferson Island, which operates a high-deliverability salt-dome storage facility in the Gulf Coast region of the U.S. While our salt-dome storage business also can generate additional revenue during times of peak market demand for natural gas storage services, the majority of its storage services are covered under medium to long-term contracts at a fixed market rate.

We are actively pursuing litigation against the State of Louisiana to obtain a court order or settlement confirming Jefferson Island's right to expand its existing facility. Jefferson Island's litigation with the State of Louisiana is described in further detail in Note 7 to our Consolidated Financial statements in Item 8 of our Annual Report on Form 10-K for the year ended December 31, 2008. In April 2009, the trial court ruled that the legislation restricting water usage from the Chicot aquifer to expand its existing storage facility is unconstitutional and invalid. In addition, the court scheduled a trial for September 28, 2009 on Jefferson Island's claim that it is authorized to expand the facility under its mineral lease. The ultimate resolution of such trial cannot be determined, but it is not expected to have a material adverse effect on our consolidated financial condition, results of operations or cash flows.

Through Golden Triangle Storage, we are constructing a new salt-dome storage facility in the Gulf Coast region of the U.S. In May 2008, Golden Triangle Storage started construction on both caverns, with the first expected to be in service in the third quarter of 2010 and the second cavern in the second quarter of 2012. We previously estimated, based on then current prices for labor, materials and pad gas that costs to construct the facility would be approximately $265 million. However, prices for labor and materials have risen significantly in the ensuing months, increasing the estimated construction cost by approximately 10% to 20%. The actual project costs depend upon the facility's configuration, materials, drilling costs, financing costs and the amount and cost of pad gas, which includes volumes of non-working natural gas used to maintain the operational integrity of the cavern facility. The costs for approximately 57% of these items have not been fixed and are subject to continued variability during the period of construction. Further, since we are not able to predict whether these costs of construction will continue to increase, moderate or decrease from current levels, we believe that there could be continued volatility in the construction cost estimates.

We also own and operate a telecommunications business, AGL Networks, which constructs and operates conduit and fiber infrastructure within select metropolitan areas.

Corporate

Our corporate segment includes our nonoperating business units, including AGL Services Company and AGL Capital.

We allocate substantially all of our corporate segment operating expenses and interest costs to our operating segments in accordance with state regulations. Our segment results include the impact of these allocations to the various operating segments. Our corporate segment also includes intercompany eliminations for transactions between our operating business segments.

Results of Operations

Operating margin and EBIT We evaluate segment performance using the measures of operating margin and EBIT, which include the effects of corporate expense allocations. Our operating margin and EBIT are not measures that are considered to be calculated in accordance with GAAP. Operating margin is a non-GAAP measure that is calculated as operating revenues minus cost of gas, which excludes operation and maintenance expense, depreciation and amortization, taxes other than income taxes, and the gain or loss on the sale of our assets; these items are included in our calculation of operating income as reflected in our condensed consolidated statements of income. EBIT is also a non-GAAP measure that includes operating income, other income and expenses. Items that we do not include in EBIT are financing costs, including interest and debt expense and income taxes, each of which we evaluate on a consolidated level.

We believe operating margin is a better indicator than operating revenues for the contribution resulting from customer growth in our distribution operations segment since the cost of gas can vary significantly and is generally billed directly to our customers. We also consider operating margin to be a better indicator in our retail energy operations, wholesale services and energy investments segments since it is a direct measure of operating margin before overhead costs. We believe EBIT is a useful measurement of our operating segments' 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.

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 attributable to AGL Resources Inc. as determined in accordance with GAAP. In addition, our operating margin or EBIT measures may not be comparable to similarly titled measures from other companies.

Seasonality The operating revenues and EBIT of our distribution operations, retail energy operations and wholesale services segments are seasonal. During the heating season, natural gas usage and operating revenues are generally higher because more customers are connected to our distribution systems and natural gas usage is higher in periods of colder weather than in periods of warmer weather. Occasionally in the summer, Sequent's operating margins are impacted due to peak usage by power generators in response to summer energy demands. Our base operating expenses, excluding cost of gas, interest expense and certain incentive compensation costs, are incurred relatively equally over any given year. Thus, our operating results vary significantly from quarter to quarter as a result of seasonality.

Seasonality also affects the comparison of certain statement of financial position items, such as receivables, inventories and short-term debt across quarters. However, these items are comparable when reviewing our annual results. Accordingly, we have presented the condensed consolidated statement of financial position as of March 31, 2008, to provide comparisons of these items to December 31, 2008, and March 31, 2009.

Hedging Changes in commodity prices subject a significant portion of our operations to earnings variability. Our nonutility businesses principally use physical and financial arrangements economically to hedge the risks associated with seasonal fluctuations in market conditions, changing commodity prices and weather. In addition, because these economic hedges may not qualify, or are not designated, for hedge accounting treatment, our reported earnings for the wholesale services and retail energy operations segments include the changes in the fair values of certain derivatives. These values may change significantly from period to period and are reflected as fair value adjustments within our operating margin.

Elizabethtown Gas utilizes certain derivatives in accordance with a directive from the New Jersey Commission to create a hedging program to hedge the impact of market fluctuations in natural gas prices. These derivative products are accounted for at fair value each reporting period. In accordance with regulatory requirements, realized gains and losses related to these derivatives are reflected in deferred natural gas costs and ultimately included in billings to customers. Unrealized gains and losses are reflected as a regulatory asset or liability, as appropriate, in our condensed consolidated statements of financial position.

The following table sets forth a reconciliation of our operating margin and EBIT to our operating income, earnings before income taxes and net income attributable to AGL Resources Inc., together with other consolidated financial information for the three months ended March 31, 2009 and 2008.

	Three months ended March 31,		
In millions, except per share data	2009	2008	Change
Operating revenues	$995	$1,012	$(17)
Cost of gas	589	657	(68)
Operating margin (1)	406	355	51
Operating expenses	176	167	9
Operating income	230	188	42
Other income	2	1	1
EBIT (1)	232	189	43
Interest expense, net	25	30	(5)
Earnings before income taxes	207	159	48
Income tax expense	72	54	18
Net income	135	105	30
Net income attributable to the noncontrolling interest	16	16	-
Net income attributable to AGL Resources Inc.	$119	$89	$30
Earnings per common share			
Basic – attributable to AGL Resources Inc. common shareholders	$1.55	$1.17	$0.38
Diluted – attributable to AGL Resources Inc. common shareholders	$1.55	$1.16	$0.39
Weighted-average number of common shares outstanding			
Basic	76.7	76.0	0.7
Diluted	76.8	76.3	0.5

(1) These are non-GAAP measurements.

Selected weather, customer and volume metrics, which we consider to be some of the key performance indicators for our operating segments, for the three months ended March 31, 2009 and 2008, are presented in the following tables. We measure the effects of weather on our business through heating degree days. Generally, increased heating degree days result in greater demand for gas on our distribution systems. However, extended and unusually mild weather during the heating season can have a significant negative impact on demand for natural gas. Our marketing and customer retention initiatives are measured by our customer metrics which can be impacted by natural gas prices, economic conditions and competition from alternative fuels. Volume metrics for distribution operations and retail energy operations present the effects of weather and our customers' demand for natural gas. Wholesale services' daily physical sales represent the daily average natural gas volumes sold to its customers.

Weather

Heating degree days (1)

	Three months ended Mar. 31, Normal	2009	2008	2009 vs. normal colder (warmer)	2009 vs. 2008 colder (warmer)
Florida	332	369	197	11%	87%
Georgia	1,441	1,434	1,510	-	(5)%
Maryland	2,510	2,612	2,339	4%	12%
New Jersey	2,527	2,627	2,422	4%	8%
Tennessee	1,640	1,664	1,721	1%	(3)%
Virginia	1,800	1,988	1,601	10%	24%

(1) Obtained from weather stations relevant to our service areas at the National Oceanic and Atmospheric Administration, National Climatic Data Center. Normal represents ten-year averages from April 2000 through March 2009.

Customers	Three months ended March 31, 2009	2008	% change
Distribution Operations			
Average end-use customers (in thousands)			
Atlanta Gas Light	1,577	1,582	(0.3)%
Chattanooga Gas	63	63	-
Elizabethtown Gas	275	274	0.4%
Elkton Gas	6	6	-
Florida City Gas	103	104	(1.0)%
Virginia Natural Gas	276	274	0.7%
Total	2,300	2,303	(0.1)%
Operation and maintenance expenses per customer	$36	$37	(3)%
EBIT per customer	$57	$53	8%
Retail Energy Operations			
Average customers in Georgia (in thousands)	518	536	(3)%
Market share in Georgia	34%	35%	(3)%

Volumes *In billion cubic feet (Bcf)*	Three months ended March 31, 2009	2008	% change
Distribution Operations			
Firm	99	98	1%
Interruptible	26	29	(10)%
Total	125	127	(2)%
Retail Energy Operations			
Georgia firm	18	19	(5)%
Ohio and Florida	5	2	150%
Wholesale Services			
Daily physical sales (Bcf/day)	3.1	2.7	15%

First quarter 2009 compared to first quarter 2008

Segment information Operating revenues, operating margin, operating expenses and EBIT information for each of our segments are contained in the following table for the three months ended March 31, 2009 and 2008.

In millions	Operating revenues	Operating margin (1)	Operating expenses	EBIT(1)
2009				
Distribution operations	$607	$252	$124	$130
Retail energy operations	343	84	21	63
Wholesale services	68	59	21	38
Energy investments	10	10	8	2
Corporate (2)	(33)	1	2	(1)
Consolidated	$995	$406	$176	$232

In millions	Operating revenues	Operating margin (1)	Operating expenses	EBIT(1)
2008				
Distribution operations	$676	$248	$126	$123
Retail energy operations	375	82	20	62
Wholesale services	17	15	14	1
Energy investments	11	11	6	5
Corporate (2)	(67)	(1)	1	(2)
Consolidated	$1,012	$355	$167	$189

(1) These are non-GAAP measures. A reconciliation of operating margin and EBIT to our operating income, earnings before income taxes and net income attributable to AGL Resources Inc. is located in “Results of Operations” herein.
(2) Includes intercompany eliminations.

For the first quarter of 2009, net income attributable to AGL Resources Inc. increased by $30 million and earnings per share attributable to AGL Resources Inc. increased by $0.38 per basic and $0.39 per diluted share compared to the same period last year. The variance between the two quarters was primarily the result of higher operating margins offset by higher operating expenses largely a result of higher incentive compensation costs due to higher earnings

Operating margin Our operating margin for the first quarter of 2009 increased by $51 million or 14% compared to the same period last year. This increase was primarily due to increased operating margins at wholesale services, supplemented by higher operating margins in the distribution operations and retail energy operations segments.

Distribution operations’ operating margin increased by $4 million or 2% compared to last year. The following table indicates the significant changes in distribution operations’ operating margin for the three months ended March 31, 2009 compared to 2008.

In millions	
Operating margin for first quarter of 2008	$248
Increased margins from gas storage carrying amounts at Atlanta Gas Light	3
Higher PRP revenues at Atlanta Gas Light	2
Reduced customer growth and usage	(1)
Operating margin for first quarter of 2009	$252

Retail energy operations’ operating margin increased by $2 million or 2%. The following table indicates the significant changes in retail energy operations’ operating margin for the three months ended March 31, 2009 compared to 2008.

In millions	
Operating margin for first quarter of 2008	$82
Higher contributions from the management of storage and transportation assets largely due to declining commodity prices in 2009	13
2008 pricing settlement with Georgia Commission	3
Higher operating margins in Ohio and Florida	3
Average customer usage	1
Change in retail pricing plan mix and decrease in average number of customers	(12)
Inventory LOCOM	(6)
Operating margin for first quarter of 2009	$84

Wholesale services’ operating margin increased $44 million compared to the first quarter of 2008 primarily due to a $47 million increase in reported hedge gains as a result of decreases in forward NYMEX natural gas prices and the narrowing of transportation basis spreads in the current period compared to rising natural gas prices and expanding transportation basis spreads in 2008. In addition, commercial activity increased $5 million due to higher volatility in the marketplace primarily associated with colder temperatures at the beginning of the period. These increases were partially offset by an $8 million LOCOM adjustment in the current period. The following table indicates the significant changes in wholesale services’ operating margin for the three months ended March 31, 2009 and 2008.

In millions	2009	2008
Commercial activity	$35	$30
Gain (loss) on transportation hedges	24	(4)
Gain (loss) on storage hedges	8	(11)
Inventory LOCOM	(8)	-
Operating margin	$59	$15

For more information on Sequent’s expected operating revenues from its storage inventory in the remainder of 2009 and in 2010 and discussion of the increased commercial activity as compared to last year, see the description of wholesale services’ business in this section beginning on page 25.

Operating Expenses Our operating expenses for the first quarter of 2009 increased $9 million or 5% as compared to the first quarter of 2008. The following table indicates the significant changes in our operating expenses.

In millions	
Operating expenses for first quarter of 2008	$167
Increased incentive compensation costs at wholesale services and retail energy operations due to increased earnings	7
Increased bad debt expense at distribution operations	1
Increased depreciation expense at distribution operations and energy investments	2
Increased legal expenses related to Jefferson Island litigation	1
Other	2
Decreased outside services, marketing and other expenses at distribution operations	(4)
Operating expenses for first quarter of 2009	$176

Interest Expense Interest expense decreased by $5 million or 17% for the three months ended March 31, 2009, primarily due to the decrease in short-term interest rates partially offset by higher average debt outstanding as indicated in the following table.

	Three months ended March 31,		
In millions	2009	2008	Change
Average debt outstanding (1)	$2,333	$2,098	$235
Average rate	4.3%	5.7%	(1.4)%

(1) Daily average of all outstanding debt.

Liquidity and Capital Resources

Our primary sources of liquidity are cash provided by operating activities, short-term borrowings under our commercial paper program (which is supported by our Credit Facilities) and borrowings under subsidiary lines of credit. Additionally, from time to time, we raise funds from the public debt and equity capital markets to fund our liquidity and capital resource needs.

Our issuance of various securities, including long-term and short-term debt, is subject to customary approval or authorization by, or filings with, state and federal regulatory bodies including state public service commissions, the SEC and the FERC. Furthermore, a substantial portion of our consolidated assets, earnings and cash flow is derived from the operation of our regulated utility subsidiaries, whose legal authority to pay dividends or make other distributions to us is subject to regulation.

We will continue to evaluate our need to increase available liquidity based on our view of working capital requirements, including the impact of changes in natural gas prices, liquidity requirements established by rating agencies and other factors. See Item 1A, “Risk Factors,” of our Annual Report on Form 10-K for the year ended December 31, 2008, for additional information on items that could impact our liquidity and capital resource requirements. The following table provides a summary of our operating, investing and financing activities.

	Three months ended Mar. 31,	
In millions	2009	2008
Net cash provided by (used in):		
Operating activities	$611	$511
Investing activities	(97)	(80)
Financing activities	(509)	(430)
Net increase in cash and cash equivalents	$5	$1

Cash Flow from Operating Activities In the first three months of 2009, our net cash flow provided from operating activities was $611 million, an increase of $100 million or 20% from the same period in 2008. This was primarily a result of a larger decrease in inventory in 2009 than 2008, primarily related to the higher cost of inventory sold in 2009. This was partially offset by increased cash collateral requirements for our derivative financial instrument activities due to the change in hedge values due to the downward shift in the forward NYMEX curve prices in 2009.

The downward shift in the forward curve results in unrealized losses on the hedging instruments, comprised primarily of exchange traded derivatives, associated with anticipated natural gas purchases. We maintain accounts with brokers to facilitate financial derivative transactions in support of our energy marketing and risk management activities. Based on the value of our positions in these accounts and the associated margin requirements, we may be required to deposit cash into these broker accounts. These unrealized losses are substantially offset by gains on derivative financial instruments utilized to hedge the price risk associated with the anticipated sale of these natural gas purchases. The anticipated economics of these transactions will ultimately be realized in the period when the natural gas is bought and sold.

Cash Flow from Investing Activities Our investing activities consisted of PP&E expenditures of $97 million for the three months ended March 31, 2009 and $80 million for the same period in 2008. The increase of $17 million or 21% in PP&E expenditures was primarily due to a $10 million increase at distribution operations, which included higher spending for the pipeline replacement program and expenditures for Virginia Natural Gas’ Hampton Roads Crossing pipeline project connecting its northern and southern systems.

Additionally, our energy investments’ PP&E expenditures increased $12 million primarily from increased expenditures at Golden Triangle Storage on our planned natural gas storage facility partially offset by decreased telecommunication expenditures at AGL Networks which expanded its Phoenix network in 2008. These PP&E expenditure increases were partially offset by decreased expenditures at retail energy operations’ of $6 million primarily due to decreased spending on information technology assets compared to 2008, when the segment transitioned to a new customer care and call center vendor.

Cash Flow from Financing Activities Our financing activities are primarily composed of borrowings and payments of short-term debt, payments of medium-term notes, issuances of senior notes, distributions to noncontrolling interests, cash dividends on our common stock, and purchases and issuances of treasury shares. Our capitalization and financing strategy is intended to ensure that we are properly capitalized with the appropriate mix of equity and debt securities. This strategy includes active management of the percentage of total debt relative to total capitalization, appropriate mix of debt with fixed to floating interest rates (our variable-rate debt target is 20% to 45% of total debt), as well as the term and interest rate profile of our debt securities. As of March 31, 2009, our variable-rate debt was 27% of our total debt, compared to 20% as of March 31, 2008. We may issue additional long-term debt in 2009 in consideration of our working capital needs and capital expenditure plans to maintain an appropriate mix.

We also work to maintain or improve our credit ratings to manage our existing financing costs effectively and enhance our ability to raise additional capital on favorable terms. Factors we consider important in assessing our credit ratings include our statements of financial position leverage, capital spending, earnings, cash flow generation, available liquidity and overall business risks. We do not have any trigger events in our debt instruments that are tied to changes in our specified credit ratings or our stock price and have not entered into any agreements that would require us to issue equity based on credit ratings or other trigger events. The following table summarizes our credit ratings as of March 31, 2009, and reflects no change from December 31, 2008.

	S&P	Moody's	Fitch
Corporate rating	A-		
Commercial paper	A-2	P-2	F-2
Senior unsecured	BBB+	Baa1	A-
Ratings outlook	Stable	Stable	Stable

Our credit ratings may be subject to revision or withdrawal at any time by the assigning rating organization, and each rating should be evaluated independently of any other rating. We cannot ensure that a rating will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances so warrant. If the rating agencies downgrade our ratings, particularly below investment grade, it may significantly limit our access to the commercial paper market and our borrowing costs would increase. In addition, we would likely be required to pay a higher interest rate in future financings, and our potential pool of investors and funding sources would decrease.

Default events Our debt instruments and other financial obligations include provisions that, if not complied with, could require early payment, additional collateral support or similar actions. Our most important default events include maintaining covenants with respect to a maximum leverage ratio, insolvency events, nonpayment of scheduled principal or interest payments, and acceleration of other financial obligations and change of control provisions.

Our Credit Facilities have financial covenants that require us to maintain a ratio of total debt to total capitalization of no greater than 70%; however, our goal is to maintain this ratio at levels between 50% and 60%. Our ratio of total debt to total capitalization calculation contained in our debt covenant includes noncontrolling interest, standby letters of credit, surety bonds and the exclusion of other comprehensive income pension adjustments. Our debt-to-equity calculation, as defined by our Credit Facilities was 53% at March 31, 2009 and 59% at December 31, 2008 and 52% at March 31, 2008. These amounts are within our required and targeted ranges. Our debt and equity capitalization ratios, as of the dates indicated, are summarized in the following table.

	Mar. 31, 2009	Dec. 31, 2008	Mar. 31, 2008
Short-term debt	10%	20%	10%
Long-term debt	44	40	42
Total debt	54	60	52
Equity	46	40	48
Total capitalization	100%	100%	100%

We believe that accomplishing our capitalization objectives and maintaining sufficient cash flow are necessary to maintain our investment-grade credit ratings and to allow us access to capital at reasonable costs. We currently comply with all existing debt provisions and covenants. For more information on our debt, see Note 6 "Debt."

Short-term debt Our short-term debt is composed of borrowings and payments under our Credit Facilities and commercial paper program, lines of credit and the current portion of our capital leases. Our short-term debt financing generally increases between June and December because our payments for natural gas and pipeline capacity are generally made to suppliers prior to the collection of accounts receivable from our customers. We typically reduce short-term debt balances in the spring because a significant portion of our current assets are converted into cash at the end of the heating season.

Excluding the current portions of gas facility revenue bonds of $114 million that we refinanced in 2008, our short-term borrowings, as of March 31, 2009, increased $148 million or 58% compared to the same period last year. This was primarily a result of $178 million increase in our margin requirements for our energy marketing and risk management activities compared to the prior year. More information on our short-term debt as of March 31, 2009, which we consider one of our primary sources of liquidity, is presented in the following table:

In millions	Capacity	Outstanding
Credit Facilities (1)	$1,140	$335
SouthStar line of credit	75	45
Sequent lines of credit	30	22
Total	$1,245	$402

(1) Supported by our $1.0 billion and $140 million Credit Facilities, and includes $335 million of commercial paper borrowings.

As of March 31, 2009 and March 31, 2008 we had no outstanding borrowings under our Credit Facilities. As of December 31, 2008, we had $500 million of outstanding borrowings under the Credit Facilities. These unsecured promissory notes are supported by our $1 billion Credit Facility which expires in August 2011 and a supplemental $140 million Credit Facility that expires in September 2009. We have the option to request an increase in the aggregate principal amount available for borrowing under the $1 billion Credit Facility to $1.25 billion on not more than three occasions during each calendar year. The $140 million Credit Facility allows for the option to request an increase in the borrowing capacity to $150 million.

Long-term debt Our long-term debt matures more than one year from the date of our statements of financial position and consists of medium-term notes, senior notes, gas facility revenue bonds, and capital leases.

For information on the maturity of our long-term debt see Note 6 to our Consolidated Financial Statements in Item 8 of our Annual Report on Form 10-K for the year ended December 31, 2008.

Contractual Obligations and Commitments We have incurred various contractual obligations and financial commitments in the normal course of our operating and financing activities. Contractual obligations include future cash payments required under existing contractual arrangements, such as debt and lease agreements. These obligations may result from both general financing activities and from commercial arrangements that are directly supported by related revenue producing activities. We also have incurred various financial commitments in the normal course of business. Contingent financial commitments represent obligations that become payable only if certain predefined events occur, such as financial guarantees, and include the nature of the guarantee and the maximum potential amount of future payments that could be required of us as the guarantor.

In March 2009, we contributed $14 million to our pension plans. We expect to make additional contributions to our pension plans of $18 million in 2009 for a total of $32 million. We previously expected that our total required and additional contributions to our pension plans would be approximately $68 million to preserve the current levels of benefits under our pension plans and in accordance with the funding requirements of the Pension Protection Act. The reduction in our expected contributions are a result of a notice from the Internal Revenue Service with respect to proposed changes to the pension funding rules that resulted in the use of a discount rate that was higher than the discount rate we used in our previous estimate. Consequently, our pension liabilities as calculated under the funding rules were reduced and the 2009 funding requirements decreased to maintain current benefits levels.

The following table illustrates our expected future contractual obligation payments such as debt and lease agreements, and commitments and contingencies as of March 31, 2009.

In millions	Total	2009	2010 & 2011	2012 & 2013	2014 & thereafter
Recorded contractual obligations:					
Long-term debt	$1,675	$-	$302	$240	$1,133
Short-term debt	403	403	-	-	-
PRP costs (1)	169	43	78	48	-
Environmental remediation liabilities (1)	105	15	40	39	11
Total	$2,352	$461	$420	$327	$1,144
Unrecorded contractual obligations and commitments (2)**:**					
Pipeline charges, storage capacity and gas supply (3)	$1,713	$420	$603	$332	$358
Interest charges (4)	933	70	166	135	562
Operating leases	130	23	45	25	37
Standby letters of credit, performance / surety bonds	51	45	6	-	-
Asset management agreements (5)	37	12	23	2	-
Total	$2,864	$570	$843	$494	$957

(1) Includes charges recoverable through rate rider mechanisms.
(2) In accordance with GAAP, these items are not reflected in our condensed consolidated statements of financial position.
(3) Charges recoverable through a natural gas cost recovery mechanism or alternatively billed to Marketers, and includes demand charges associated with Sequent. Also includes SouthStar's gas commodity purchase commitments of 22 Bcf at floating gas prices calculated using forward natural gas prices as of March 31, 2009, and are valued at $90 million. Additionally, includes amounts associated with a subsidiary of NUI which entered into two 20-year agreements for the firm transportation and storage of natural gas during 2003 with annual aggregate demand charges of approximately $5 million. As a result of our acquisition of NUI and in accordance with SFAS 141, we valued the contracts at fair value and established a long-term liability of $38 million for the excess liability that will be amortized to our consolidated statements of income over the remaining lives of the contracts of $2 million annually through November 2023 and $1 million annually from November 2023 to November 2028.
(4) Floating rate debt is based on the interest rate as of March 31, 2009, and the maturity of the underlying debt instrument. As of March 31, 2009, we have $31 million of accrued interest on our consolidated statements of financial position that will be paid in 2009.
(5) Represent fixed-fee minimum payments for Sequent's affiliated asset management.

Critical Accounting Policies and Estimates

The preparation of our financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosures of contingent assets and liabilities. We base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. We evaluate our estimates on an ongoing basis, and our actual results may differ from these estimates. Our critical accounting policies used in the preparation of our condensed consolidated financial statements include the following:

- Pipeline Replacement Program
- Environmental Remediation Liabilities
- Derivatives and Hedging Activities
- Pension and Other Postretirement Plans
- Income Taxes

Each of our critical accounting policies and estimates 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. There have been no significant changes to our critical accounting policies from those disclosed in our Annual Report on Form 10-K for the year ended December 31, 2008.

Accounting Developments

Previously discussed

SFAS 160 SFAS 160 requires us to present our minority interest, as noncontrolling interest, separately within the capitalization section of our condensed consolidated statements of financial position. We adopted SFAS 160 on January 1, 2009. More information on our adoption of SFAS 160 is discussed in Note 5.

SFAS 161 SFAS 161 amends the disclosure requirements of SFAS 133 to provide an enhanced understanding of how and why derivative instruments are used, how they are accounted for and their effect on an entity's financial condition, performance and cash flows. We adopted SFAS 161 on January 1, 2009 and provided the required additional disclosures, but it had no financial impact to our consolidated results of operations, cash flows or financial condition. More information on our adoption of SFAS 160 is discussed in Note 3.

FSP EITF 03-6-1 This FSP became effective on January 1, 2009 and provides guidance on the computation of earnings per share when a company has unvested share awards outstanding that have the right to receive dividends. The effects of this FSP were immaterial to our calculation of earnings per share.

FSP FAS 133-1 This FSP requires more detailed disclosures about credit derivatives, including the potential adverse effects of changes in credit risk on the financial position, financial performance and cash flows of the sellers of the instruments. This FSP had no financial impact to our consolidated results of operations, cash flows or financial condition. We adopted FSP FAS 133-1 on January 1, 2009.

Recently issued

FSP FAS 132(R)-1 This FSP requires additional disclosures relating to postretirement benefit plan assets to provide transparency regarding the types of assets and the associated risks within the types of plan assets. The required disclosures include:

- How investment allocation decisions are made, including information that provides an understanding of investment policies and strategies,
- The major categories of plan assets,
- Inputs and valuation techniques used to measure the fair value of plan assets, including those measurements using significant unobservable inputs, on changes in plan assets for the period, and
- Significant concentrations of risk within plan assets.

This FSP is effective for fiscal years ending after December 15, 2009 and requires additional disclosures in our notes to condensed consolidated financial statements, but will not have a material impact on our financial position, results of operations or cash flows.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to risks associated with commodity prices, interest rates and credit. Commodity price risk is defined as the potential loss that we may incur as a result of changes in the fair value of natural gas. 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 Atlanta Gas Light in distribution operations and in wholesale services.

Our Risk Management Committee (RMC) is responsible for establishing the overall risk management policies and monitoring compliance with, and adherence to, the terms within these policies, including approval and authorization levels and delegation of these levels. Our RMC consists of members of senior management who monitor open commodity price risk positions and other types of risk, corporate exposures, credit exposures and overall results of our risk management activities. It 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. Our risk management activities and related accounting treatments for our derivative financial instruments are described in further detail in Note 3.

Commodity Price Risk

Retail Energy Operations SouthStar's use of derivative financial instruments is governed by a risk management policy, approved and monitored by its Finance and Risk Asset Management Committee, which prohibits the use of derivatives for speculative purposes.

SouthStar routinely utilizes various types of derivative financial instruments to mitigate certain commodity price and weather risk inherent in the natural gas industry. This includes the active management of storage positions through a variety of hedging transactions for the purpose of managing exposures arising from changing commodity prices. SouthStar uses these hedging instruments to lock in economic margins (as spreads between wholesale and retail commodity prices widen between periods) and thereby minimize its exposure to declining operating margins.

The following tables illustrate the change in the net fair value of the derivative financial instruments during the three months ended March 31, 2009 and 2008, and provide details of the net fair value of derivative financial instruments outstanding as of March 31, 2009.

In millions	Three months ended Mar. 31, 2009	2008
Net fair value of derivative financial instruments outstanding at beginning of period	$(17)	$10
Derivative financial instruments realized or otherwise settled during period	4	(7)
Change in net fair value of derivative financial instruments	(9)	3
Net fair value of derivative financial instruments outstanding at end of period	(22)	6
Netting of cash collateral	27	-
Cash collateral and net fair value of derivative financial instruments outstanding at end of period	$5	$6

The sources of SouthStar's net fair value of its commodity-related derivative financial instruments at March 31, 2009, are as follows:

In millions	Prices actively quoted (Level 1) (1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
Mature through			
2009	$(28)	$(1)	$-
2010	7	-	-
Total derivative financial instruments (2)	$(21)	$(1)	$-

(1) Valued using NYMEX futures prices.
(2) Excludes cash collateral amounts.

The following tables include the fair values and average values of SouthStar's derivative financial instruments as of the dates indicated. SouthStar bases the average values on monthly averages for the three months ended March 31, 2009 and 2008.

In millions	Derivative financial instruments average fair values (1) at Mar. 31, 2009	2008
Asset	$11	$5
Liability	35	1

(1) Excludes cash collateral amounts.

In millions	Derivative financial instruments fair values netted with cash collateral at Mar. 31, 2009	Dec. 31, 2008	Mar. 31, 2008
Asset	$10	$16	$7
Liability	5	2	1

Value at Risk A 95% confidence interval is used to evaluate VaR exposure. A 95% confidence interval means that over the holding period, an actual loss in portfolio value is not expected to exceed the calculated VaR more than 5% of the time. We calculate VaR based on the variance-covariance technique. This technique requires several assumptions for the basis of the calculation, such as price distribution, 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. SouthStar's portfolio of positions for the three months ended March 31, 2009 and 2008 had quarterly average 1-day holding period VaRs of less than $100,000 and its high, low and period end 1-day holding period VaR were immaterial.

Wholesale Services Sequent routinely utilizes various types of derivative financial instruments to mitigate certain commodity price risks inherent in the natural gas industry. These instruments include a variety of exchange-traded and OTC energy contracts, such as forward contracts, futures contracts, options contracts and financial swap agreements.

The following tables include the fair values and average values of Sequent's derivative financial instruments as of the dates indicated. Sequent bases the average values on monthly averages for the three months ended March 31, 2009 and 2008.

In millions	Derivative financial instruments average values (1) at Mar. 31, 2009	2008
Asset	$187	$42
Liability	82	37

(1) Excludes cash collateral amounts.

In millions	Derivative financial instruments fair values netted with cash collateral at Mar. 31, 2009	Dec. 31, 2008	Mar. 31, 2008
Asset	$211	$206	$44
Liability	17	27	26

Sequent experienced a $75 million decrease in the net fair value of its outstanding contracts during the first three months of 2009 and 2008 due to changes in the fair value of derivative financial instruments utilized in its energy marketing and risk management activities and contract settlements.

The following tables illustrate the change in the net fair value of Sequent's derivative financial instruments during the three months ended March 31, 2009 and 2008, and provide details of the net fair value of contracts outstanding as of March 31, 2009.

In millions	Three months ended Mar. 31, 2009	2008
Net fair value of derivative financial instruments outstanding at beginning of period	$82	$57
Derivative financial instruments realized or otherwise settled during period	(95)	(42)
Change in net fair value of derivative financial instruments	20	(33)
Net fair value of derivative financial instruments outstanding at end of period	7	(18)
Netting of cash collateral	187	36
Cash collateral and net fair value of derivative financial instruments outstanding at end of period	$194	$18

The sources of Sequent's net fair value of its commodity-related derivative financial instruments at March 31, 2009, are as follows:

In millions	Prices actively quoted (Level 1) (1)	Significant other observable inputs (Level 2) (2)	Significant unobservable inputs (Level 3)
Mature through			
2009	$(120)	$105	$-
2010 - 2011	(20)	33	-
2012 - 2014	2	7	-
Total derivative financial instruments (3)	$(138)	$145	$-

(1) Valued using NYMEX futures prices and other quoted sources.
(2) Valued using basis transactions that represent the cost to transport the commodity from a NYMEX delivery point to the contract delivery point. These transactions are based on quotes obtained either through electronic trading platforms or directly from brokers.
(3) Excludes cash collateral amounts.

Value at Risk Sequent's 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 Sequent generally manages physical gas assets and economically protects its positions by hedging in the futures markets, its open exposure is generally immaterial, permitting Sequent to operate within relatively low VaR limits. Sequent employs daily risk testing, using both VaR and stress testing, to evaluate the risks of its open positions.

Sequent's management actively monitors open commodity positions and the resulting VaR. Sequent continues to maintain a relatively matched book, where its total buy volume is close to sell volume with minimal open commodity risk. Based on a 95% confidence interval and employing a 1-day holding period for all positions, Sequent's portfolio of positions for the three months ended March 31, 2009 and 2008 had the following VaRs.

	Three months ended March 31,	
In millions	2009	2008
Period end	$2.1	$2.9
Average	1.9	1.4
High	3.3	2.9
Low	1.3	0.8

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. Based on $563 million of variable-rate debt, which includes $402 million of our variable-rate short-term debt and $161 million of variable-rate gas facility revenue bonds outstanding at March 31, 2009, a 100 basis point change in market interest rates from 0.76% to 1.76% would have resulted in an increase in pretax interest expense of $6 million on an annualized basis.

Credit 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 Sequent is engaged in more than one outstanding derivative transaction with the same counterparty and it has 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 Sequent's credit risk. Sequent also uses other netting agreements with certain counterparties with whom it conducts 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. Sequent conducts credit evaluations and obtains appropriate internal approvals for its 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, Sequent requires credit enhancements by way of guaranty, cash deposit or letter of credit for counterparties that do not meet the minimum long-term debt rating 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, 2009, Sequent's top 20 counterparties represented approximately 69% of the total counterparty exposure of $325 million, derived by adding together the top 20 counterparties' exposures and dividing by the total of Sequent's counterparties' exposures.

As of March 31, 2009, Sequent's counterparties, or the counterparties' guarantors, had a weighted-average S&P equivalent credit rating of A-, which is consistent with the rating at December 31, 2008 and March 31, 2008. The S&P equivalent credit rating is determined by a process of converting the lower of the S&P and Moody's ratings to an internal rating ranging from 9 to 1, with 9 being the equivalent to AAA/Aaa by S&P and Moody's and 1 being D or Default by S&P and Moody's. A counterparty that does not have an external rating is assigned an internal rating based on the strength of the financial ratios for that counterparty. To arrive at the weighted average credit rating, each counterparty's assigned internal ratio is multiplied by the counterparty's credit exposure and summed for all counterparties. The sum is divided by the aggregate total counterparties' exposures, and this numeric value is then converted to an S&P equivalent. There were no credit defaults with Sequent's counterparties.

The following table shows Sequent's third-party commodity receivable and payable positions as of March 31, 2009 and 2008 and December 31, 2008.

	Gross receivables			Gross payables		
In millions	**March 31, 2009**	**Dec. 31, 2008**	**March 31, 2008**	**March 31, 2009**	**Dec. 31, 2008**	**March 31, 2008**
Netting agreements in place:						
Counterparty is investment grade	$237	$398	$483	$168	$266	$439
Counterparty is non-investment grade	8	15	46	19	41	30
Counterparty has no external rating	76	129	91	153	228	239
No netting agreements in place:						
Counterparty is investment grade	5	7	4	2	4	3
Amount recorded on statements of financial position	$326	$549	$624	$342	$539	$711

Sequent has certain trade and credit contracts that have explicit minimum credit rating requirements. These credit rating requirements typically give counterparties the right to suspend or terminate credit if our credit ratings are downgraded to non-investment grade status. Under such circumstances, Sequent would need to post collateral to continue transacting business with some of its counterparties. Posting collateral would have a negative effect on our liquidity. If such collateral were not posted, Sequent's ability to continue transacting business with these counterparties would be impaired. If, at March 31, 2009, our credit ratings had been downgraded to non-investment grade status, the required amounts to satisfy potential collateral demands under such agreements between Sequent and its counterparties would have totaled $12 million.

There have been no other significant changes to our credit risk related to our other segments, as described in Item 7A "Quantitative and Qualitative Disclosures about Market Risk" of our Annual Report on Form 10-K for the year ended December 31, 2008.

Item 4. Controls and Procedures

(a) ***Evaluation of disclosure controls and procedures*****.** Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of our disclosure controls and procedures, as such term is defined in Rule 13a-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the Exchange Act), as of March 31, 2009, the end of the period covered by this report. Based on this evaluation, our principal executive officer and our principal financial officer concluded that our disclosure controls and procedures were effective as of March 31, 2009, in providing a reasonable level of assurance that information we are required to disclose in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods in SEC rules and forms, including a reasonable level of assurance that information required to be disclosed by us in such reports is accumulated and communicated to our management, including our principal executive officer and our principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

(b) ***Changes in internal control over financial reporting*****.** There were no changes in our internal control over financial reporting during our most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control 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 litigation incidental to the business. For information regarding pending federal and state regulatory matters, see “Note 7 - Commitments and Contingencies” contained in Item 1 of Part I under the caption “Notes to Condensed Consolidated Financial Statements (Unaudited).”

In March 2009, Piedmont filed a lawsuit in the Court of Chancery of the State of Delaware against GNGC, asking the court to enter a judgment declaring that GNGC’s right to purchase Piedmont’s ownership interest in SouthStar expires on November 1, 2009. We believe that, under the March 2004 amended and restated joint venture agreement, GNGC has the evergreen opportunity, throughout the term of the joint venture, to exercise its options to purchase a portion of, or all of, Piedmont’s interest in SouthStar by notifying Piedmont on or before November of each year, with the purchase being effective as of January 1 of the following year. The ultimate resolution of this litigation cannot be determined, but we believe that the dispute will be resolved before our next option exercise notification date on November 1, 2009.

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. Unregistered Sales of Equity Securities and Use of Proceeds

The following table sets forth information regarding purchases of our common stock by us and any affiliated purchasers during the three months ended March 31, 2009. Stock repurchases may be made in the open market or in private transactions at times and in amounts that we deem appropriate. However, there is no guarantee as to the exact number of additional shares that may be repurchased, and we may terminate or limit the stock repurchase program at any time. We will hold the repurchased shares as treasury shares.

Period	Total number of shares purchased (1) (2) (3)	Average price paid per share	Total number of shares purchased as part of publicly announced plans or programs (3)	Maximum number of shares that may yet be purchased under the publicly announced plans or programs (3)
January 2009	4,500	$30.33	-	4,950,951
February 2009	14,200	33.53	-	4,950,951
March 2009	-	-	-	4,950,951
Total first quarter	18,700	$32.76	-	

(1) The total number of shares purchased includes an aggregate of 8,650 shares surrendered to us to satisfy tax withholding obligation in connection with the vesting of shares of restricted stock and the exercise of stock options.

(2) On March 20, 2001, our Board of Directors approved the purchase of up to 600,000 shares of our common stock in the open market to be used for issuances under the Officer Incentive Plan (Officer Plan). We purchased 10,050 shares for such purposes in the first quarter of 2009. As of March 31, 2009, we had purchased a total 322,417 of the 600,000 shares authorized for purchase, leaving 277,583 shares available for purchase under this program.

(3) On February 3, 2006, we announced that our Board of Directors had authorized a plan to repurchase up to a total of 8 million shares of our common stock, excluding the shares remaining available for purchase in connection with the Officer Plan as described in note (2) above, over a five-year period.

Item 6. Exhibits

10.6 Fourth Modification to the amended and Restated Master Environmental Management Services Agreement dated as of February 1, 2009 by and between Atlanta Gas Light Company and the RETEC Group, Inc.

31.1 Certification of John W. Somerhalder II pursuant to Rule 13a - 14(a).

31.2 Certification of Andrew W. Evans pursuant to Rule 13a - 14(a).

32.1 Certification of John W. Somerhalder II pursuant to 18 U.S.C. Section 1350.

32.2 Certification of Andrew W. Evans pursuant to 18 U.S.C. Section 1350.

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 29, 2009 /s/ Andrew W. Evans
Executive Vice President and Chief Financial Officer