AGL RESOURCES INC
Form 10-Q
July 30, 2009

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

FORM 10-Q
(Mark One)
þ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Quarterly Period Ended June 30, 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 þ 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 þ	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 þ

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 July 24, 2009
Common Stock, $5.00 Par Value	77,278,942

Glossary

Table of Contents

AGL RESOURCES INC.

Quarterly Report on Form 10-Q

For the Quarter Ended June 30, 2009

TABLE OF CONTENTS

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 and other income 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 current 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
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”
EITF 99-2	EITF 99-2, "Accounting for Weather Derivatives"
FSP EITF 03-6-1	FSP EITF 03-6-1, “Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities”
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 140-4	FSP No. FAS 140-4, “Disclosures by Public Entities about Transfers of Financial Assets”
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”
FSP FAS 157-4	FSP No. FAS 157-4, “Determining Whether a Market Is Not Active and a Transaction Is Not Distressed”
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”

SFAS 162	SFAS No. 162, “The Hierarchy of Generally Accepted Accounting Principles”
SFAS 165	SFAS No. 165, “Subsequent Events”
SFAS 166	SFAS No. 166, “Accounting for Transfers of Financial Assets”
SFAS 167	SFAS No. 167, “Amendments to FASB Interpretation No. 46(R)”
SFAS 168	SFAS No. 168, “The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles”

Glossary

Table of Contents

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	June 30, 2009	As of December 31, 2008	June 30, 2008
Current assets			
Cash and cash equivalents	$ 12	$ 16	$ 19
Inventories, net (Note 1)	532	663	708
Receivables			
Energy marketing receivables (Note 1)	276	549	807
Gas, unbilled and other receivables	209	472	258
Less allowance for uncollectible accounts	(19)	(16)	(19)
Total receivables	466	1,005	1,046
Derivative financial instruments – current portion (Note 2 and Note 3)	177	207	107
Unrecovered pipeline replacement program costs – current portion (Note 1)	41	41	37
Unrecovered environmental remediation costs – current portion (Note 1)	14	18	20
Other current assets	74	92	106
Total current assets	1,316	2,042	2,043
Long-term assets and other deferred debits			
Property, plant and equipment	5,685	5,500	5,284
Less accumulated depreciation	1,729	1,684	1,621
Property, plant and equipment-net	3,956	3,816	3,663
Goodwill	418	418	420
Unrecovered pipeline replacement program costs (Note 1)	174	196	216
Unrecovered environmental remediation costs (Note 1)	146	125	130
Derivative financial instruments (Note 2 and Note 3)	37	38	25
Other	73	75	94
Total long-term assets and other deferred debits	4,804	4,668	4,548
Total assets	$ 6,120	$ 6,710	$ 6,591
Current liabilities			
Short-term debt (Note 6)	$ 418	$ 866	$ 513
Energy marketing trade payables (Note 1)	317	539	927
Accounts payable - trade	167	202	158
Accrued expenses	107	113	106
Deferred natural gas costs (Note 1)	52	25	20
	50	49	48

Accrued pipeline replacement program costs – current portion (Note 1)			
Customer deposits	48	50	33
Derivative financial instruments – current portion (Note 2 and Note 3)	36	50	112
Accrued environmental remediation liabilities – current portion (Note 1 and Note 7)	19	17	15
Other current liabilities	67	72	47
Total current liabilities	1,281	1,983	1,979
Long-term liabilities and other deferred credits			
Long-term debt (Note 6)	1,675	1,675	1,637
Accumulated deferred income taxes	609	571	604
Accumulated removal costs (Note 1)	199	178	175
Accrued pension obligations (Note 4)	187	199	44
Accrued environmental remediation liabilities (Note 1 and Note 7)	114	89	92
Accrued pipeline replacement program costs (Note 1)	113	140	162
Accrued postretirement benefit costs (Note 4)	44	46	21
Derivative financial instruments (Note 2 and Note 3)	3	6	13
Other long-term liabilities and other deferred credits	136	139	144
Total long-term liabilities and other deferred credits	3,080	3,043	2,892
Commitments and contingencies (Note 7)			
Equity (Note 5)			
AGL Resources Inc. common shareholders' equity, $5 par value; 750,000,000 shares authorized	1,732	1,652	1,686
Noncontrolling interest	27	32	34
Total equity	1,759	1,684	1,720
Total liabilities and equity	$ 6,120	$ 6,710	$ 6,591

See Notes to Condensed Consolidated Financial Statements (Unaudited).

Glossary

Table of Contents

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

	Three months ended June 30,		Six months ended June 30,	
In millions, except per share amounts	2009	2008	2009	2008
Operating revenues	$ 377	$ 444	$ 1,372	$ 1,456
Operating expenses				
Cost of gas	152	275	741	932
Operation and maintenance	119	114	244	233
Depreciation and amortization	39	38	78	74
Taxes other than income taxes	12	11	24	23
Total operating expenses	322	438	1,087	1,262
Operating income	55	6	285	194
Other income	3	3	5	4
Interest expense, net	(24)	(26)	(49)	(56)
Earnings (loss) before income taxes	34	(17)	241	142
Income tax expense (benefit)	13	(7)	85	47
Net income (loss)	21	(10)	156	95
Less net income attributable to the noncontrolling interest (Note 5)	1	1	17	17
Net income (loss) attributable to AGL Resources Inc.	$ 20	$ (11)	$ 139	$ 78
Per common share data (Note 1)				
Basic earnings (loss) per common share attributable to AGL Resources Inc. common shareholders	$ 0.26	$ (0.15)	$ 1.81	$ 1.02
Diluted earnings (loss) per common share attributable to AGL Resources Inc. common shareholders	$ 0.26	$ (0.15)	$ 1.81	$ 1.01
Cash dividends declared per common share	$ 0.43	$ 0.42	$ 0.86	$ 0.84
Weighted-average number of common shares outstanding (Note 1)				
Basic	76.7	76.2	76.8	76.2
Diluted	76.9	76.2	76.9	76.4

See Notes to Condensed Consolidated Financial Statements (Unaudited).

Glossary

Table of Contents

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

	AGL Resources Inc. Common Shareholders Equity							
	Common stock		Premium on common	Earnings	Accumulated other comprehensive	Treasury	Noncontrolling	
In millions, except per share amounts	Shares	Amount	stock	reinvested	loss	shares	interest	Total
Balance as of December 31, 2007	76.4	$ 390	$ 667	$ 680	$ (13)	$ (63)	$ 47	$ 1,708
Net income	-	-	-	78	-	-	17	95
Other comprehensive loss	-	-	-	-	(1)	-	-	(1)
Dividends on common stock ($0.84 per share)	-	-	-	(64)	-	-	-	(64)
Distributions to noncontrolling interest	-	-	-	-	-	-	(30)	(30)
Issuance of treasury shares	0.3	-	-	(3)	-	11	-	8
Stock-based compensation expense (net of taxes) (Note 5)	-	-	4	-	-	-	-	4
Balance as of June 30, 2008	76.7	$ 390	$ 671	$ 691	$ (14)	$ (52)	$ 34	$ 1,720

	AGL Resources Inc. Common Shareholders Equity							
	Common stock		Premium on common	Earnings	Accumulated other comprehensive	Treasury	Noncontrolling	
In millions, except per share amounts	Shares	Amount	stock	reinvested	loss	shares	interest	Total
Balance as of December 31, 2008	76.9	$ 390	$ 676	$ 763	$ (134)	$ (43)	$ 32	$ 1,684
Net income	-	-	-	139	-	-	17	156
Other comprehensive loss	-	-	-	-	(3)	-	(2)	(5)
Dividends on common stock ($0.86 per share)	-	-	-	(66)	-	(2)	-	(68)
Distributions to noncontrolling interest	-	-	-	-	-	-	(20)	(20)
Issuance of treasury shares	0.4	-	(6)	(3)	-	17	-	8
Stock-based compensation expense (net of taxes) (Note 5)	-	-	4	-	-	-	-	4
	77.3	$ 390	$ 674	$ 833	$ (137)	$ (28)	$ 27	$ 1,759

Balance as of June 30,
2009

See Notes to Condensed Consolidated Financial Statements (Unaudited).

Glossary

Table of Contents

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

	Three months ended June 30,		Six months ended June 30,	
In millions	2009	2008	2009	2008
Comprehensive income (loss) attributable to AGL Resources Inc. (net of tax)				
Net income (loss) attributable to AGL Resources Inc.	$ 20	$ (11)	$ 139	$ 78
Cash flow hedges:				
Derivative financial instruments unrealized (losses) gains arising during the period	(1)	2	(11)	4
Reclassification of derivative financial instruments realized losses (gains) included in net income	6	(1)	8	(5)
Other comprehensive income (loss)	5	1	(3)	(1)
Comprehensive income (loss) (Note 5)	$ 25	$ (10)	$ 136	$ 77
Comprehensive income attributable to noncontrolling interest (net of tax)				
Net income attributable to noncontrolling interest	$ 1	$ 1	$ 17	$ 17
Cash flow hedges:				
Derivative financial instruments unrealized (losses) gains arising during the period	(1)	1	(6)	2
Reclassification of derivative financial instruments realized losses (gains) included in net income	3	(1)	4	(2)
Other comprehensive income (loss)	2	-	(2)	-
Comprehensive income (Note 5)	$ 3	$ 1	$ 15	$ 17
Total comprehensive income (loss), including portion attributable to noncontrolling interest (net of tax)				
Net income (loss)	$ 21	$ (10)	$ 156	$ 95
Cash flow hedges:				
Derivative financial instruments unrealized (losses) gains arising during the period	(2)	3	(17)	6
Reclassification of derivative financial instruments realized losses (gains) included in net income	9	(2)	12	(7)
Other comprehensive income (loss)	7	1	(5)	(1)
Comprehensive income (loss) (Note 5)	$ 28	$ (9)	$ 151	$ 94

See Notes to Condensed Consolidated Financial Statements (Unaudited).

Glossary

Table of Contents

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

In millions	Six months ended June 30, 2009	2008
Cash flows from operating activities		
Net income	$ 156	$ 95
Adjustments to reconcile net income to net cash flow provided by operating activities		
Depreciation and amortization	78	74
Deferred income taxes	29	(34)
Change in derivative financial instrument assets and liabilities	14	51
Changes in certain assets and liabilities		
Gas, unbilled and other receivables	266	152
Inventories	131	(157)
Energy marketing receivables and energy marketing trade payables, net	51	140
Accrued expenses	(6)	19
Gas and trade payables	(35)	(14)
Other – net	47	33
Net cash flow provided by operating activities	731	359
Cash flows from investing activities		
Payments to acquire, property, plant and equipment	(207)	(166)
Net cash flow used in investing activities	(207)	(166)
Cash flows from financing activities		
Net payments and borrowings of short-term debt	(448)	(67)
Dividends paid on common shares	(68)	(64)
Distribution to noncontrolling interest	(20)	(30)
Issuance of treasury shares	8	8
Payments of long-term debt	-	(161)
Issuance of variable rate gas facility revenue bonds	-	122
Other	-	(1)
Net cash flow used in financing activities	(528)	(193)
Net decrease in cash and cash equivalents	(4)	-
Cash and cash equivalents at beginning of period	16	19
Cash and cash equivalents at end of period	$ 12	$ 19
Cash paid during the period for		
Interest	$ 47	$ 59
Income taxes	$ 35	$ 24

See Notes to Condensed Consolidated Financial Statements (Unaudited).

Glossary

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

Note 1 - Accounting Policies and Methods of Application

General

AGL Resources Inc. is an energy services holding company that conducts substantially all of its operations through its subsidiaries. Unless the context requires otherwise, references to “we,” “us,” “our,” or “the company” 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 recast consolidated financial statements and related notes as filed on Form 8-K with the SEC on July 13, 2009, and in our 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 and six months ended June 30, 2009 and 2008, and our financial condition as of December 31, 2008, and June 30, 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 and wholesale 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.

Our wholesale services segment 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. As of June 30, 2009, December 31, 2008 and June 30, 2008 the collateral that wholesale services would be required to post would not have a material impact to our consolidated results of operations, cash flows or financial condition. However, if such collateral were not posted, wholesale services' ability to continue transacting business with these counterparties would be impaired.

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 Elizabethtown Gas' derivative financial instruments, are summarized in the following table. For more information on our derivative financial instruments, see Note 3.

Table of Contents

In millions	June 30 2009	Dec. 31 2008	June 30 2008
Regulatory assets			
Unrecovered PRP costs	$ 215	$ 237	$ 253
Unrecovered ERC	160	143	150
Unrecovered postretirement benefit costs	10	11	11
Unrecovered seasonal rates	-	11	-
Unrecovered natural gas costs	-	19	22
Elizabethtown Gas derivative financial instruments	-	-	35
Other	28	30	28
Total regulatory assets	413	451	499
Associated assets			
Elizabethtown Gas derivative financial instruments	21	23	-
Total regulatory and associated assets	$ 434	$ 474	$ 499
Regulatory liabilities			
Accumulated removal costs	$ 199	$ 178	$ 175
Deferred natural gas costs	52	25	20
Elizabethtown Gas derivative financial instruments	21	23	-
Deferred seasonal rates	9	-	9
Regulatory tax liability	18	19	19
Unamortized investment tax credit	14	14	15
Other	17	22	20
Total regulatory liabilities	330	281	258
Associated liabilities			
PRP costs	163	189	210
ERC	120	96	97
Elizabethtown Gas derivative financial instruments	-	-	35
Total associated liabilities	283	285	342
Total regulatory and associated liabilities	$ 613	$ 566	$ 600

There have been no significant changes to our regulatory assets and liabilities as described in Note 1 to our recast consolidated financial statements as filed on Form 8-K with the SEC on July 13, 2009, and in our Form 10-K for the year ended December 31, 2008, filed with the SEC on February 5, 2009.

Inventories

For our distribution operations segment, we record natural gas stored underground at WACOG. 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 six months ended June 30, 2009 and did not record LOCOM adjustments in the six months ended June 30, 2008. Sequent recorded LOCOM adjustments of $8 million in the six months ended June 30, 2009 and did not record LOCOM adjustments for the six months ended June 30, 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 for 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 stock 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 June 30,	
In millions	2009	2008
Denominator for basic earnings per share (1)	76.7	76.2
Assumed exercise of restricted stock, restricted stock units and stock options	0.2	-
Denominator for diluted earnings per share	76.9	76.2

(1) Daily weighted-average shares outstanding.

Glossary

Table of Contents

In millions	Six months ended June 30, 2009	2008
Denominator for basic earnings per share (1)	76.8	76.2
Assumed exercise of restricted stock, restricted stock units and stock options	0.1	0.2
Denominator for diluted earnings per share	76.9	76.4

(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:

In millions	June 30, 2009	2008
Three months ended	2.3	1.7
Six months ended	2.2	1.6

The increase of 0.6 million shares for the three and six months ended June 30, 2009, 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 June 30, 2009 as compared to June 30, 2008.

Accounting Developments

Recently issued

SFAS 166 In June 2009, the FASB issued SFAS 166, which amends FAS 140-4, and requires improved disclosures about transfers of financial assets and removes the exception from applying FIN 46(R) to qualifying special purpose entities. SFAS 166 will be effective for us on January 1, 2010 and will have no effect on our consolidated results of operations, cash flows and financial position.

SFAS 167 In June 2009, the FASB issued SFAS 167, which provides new consolidation guidance for variable interest entities (VIE). SFAS 167 requires a company to assess the determination of the primary beneficiary of a VIE based on whether the company has the power to direct matters that most significantly impact the activities of the VIE, and the obligation to absorb losses or the right to receive benefits of the VIE. In addition, SFAS 167 requires ongoing reassessments of whether a company is the primary beneficiary of a VIE.

SFAS 167 will be effective for us beginning January 1, 2010. Earlier application is prohibited. We are currently evaluating the impact of this standard on our consolidated results of operations, cash flows and financial position.

SFAS 168 In June 2009, the FASB issued SFAS 168, which replaces SFAS 162. SFAS 168 creates a two-level GAAP hierarchy - authoritative and non-authoritative - and establishes the FASB's Accounting Standards Codification (Codification) as the sole source of authoritative GAAP for non-governmental entities, except for rules and releases by the SEC.

After July 1, 2009, all non-grandfathered, non-SEC accounting guidance not included in the Codification is superseded and is deemed non-authoritative. SFAS 168 is effective for financial statements issued for interim and annual periods ending after September 15, 2009. SFAS 168 will have no impact on our consolidated results of operations, cash flows and financial position.

Note 2 - Fair Value Measurements

The carrying value of cash and cash equivalents, receivables, accounts payable, short-term debt, other current assets and 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 June 30, 2009	$ 1,676	$ 1,725
As of December 31, 2008	1,676	1,647
As of June 30, 2008	1,638	1,635

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.

FSP FAS 157-4 This FSP establishes a two-step process to determine if the market for a financial asset is inactive and a transaction is not distressed. Step 1 provides factors that include, but are not limited to: transaction frequency, varying price quotations, index correlation, liquidity risk premiums, price spread increases and availability of public information. If a company determines the market is inactive, Step 2 must be applied.

Glossary

In Step 2 an entity must presume that a quoted price is associated with a distressed transaction unless there was sufficient time before the measurement date to allow for usual and customary marketing activities, including multiple bidders. This FSP is effective for interim and annual periods ending after June 15, 2009. We adopted this FSP in the second quarter of 2009. Currently, this FSP does not effect us, as our financial assets are traded in active markets.

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 three levels of the fair value hierarchy defined by SFAS 157 are as follows:

Level 1

Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Our Level 1 items consist of financial instruments with exchange-traded derivatives.

Level 2

Pricing inputs are other than quoted prices in active markets included in level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial and commodity instruments that are valued using valuation methodologies. These methodologies are primarily industry-standard methodologies that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. We obtain market price data from multiple sources in order to value some of our Level 2 transactions and this data is representative of transactions that occurred in the market place. As we aggregate our disclosures by counterparty, the underlying transactions for a given counterparty may be a combination of exchange-traded derivatives and values based on other sources. Instruments in this category include shorter tenor exchange-traded and non-exchange-traded derivatives such as OTC forwards and options.

Level 3

Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management’s best estimate of fair value. Level 3 instruments include those that may be more structured or otherwise tailored to customers’ needs. We do not have any material assets or liabilities classified as 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 June 30, 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 instruments, see Note 3.

Glossary

Table of Contents

	Recurring fair values					
	Natural gas derivative financial instruments					
	June 30, 2009		December 31, 2008		June 30, 2008	
In millions	Assets	Liabilities	Assets (1)	Liabilities	Assets	Liabilities
Quoted prices in active markets (Level 1)	$34	$(105)	$52	$(117)	$28	$(84)
Significant other observable inputs (Level 2)	140	(18)	154	(28)	86	(118)
Netting of cash collateral	40	84	35	89	18	77
Total carrying value (2)	$214	$(39)	$241	$(56)	$132	$(125)

(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 Financial Instruments 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.

		As of	
In millions	June 30, 2009	Dec. 31, 2008	June 30, 2008
Right to reclaim cash collateral	$ 124	$ 128	$ 103
Obligations to return cash collateral	-	(4)	(8)
Total cash collateral	$ 124	$ 124	$ 95

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 types of derivative financial instruments and physical transactions to manage natural gas 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, which consists of members of senior management and 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.

Natural Gas Derivative Financial Instruments

Activities associated with natural gas price risk management activities and derivative financial 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 of cash totaling $14 million in 2009 and $51 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.

Glossary

Table of Contents

Retail Energy Operations SouthStar uses natural gas derivative financial instruments (futures, options and swaps) to manage exposures arising from changing natural gas prices. SouthStar's objective for holding these derivatives is to utilize the most effective method to reduce or eliminate the impact of this exposure. 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 have designated a portion of SouthStar's derivative financial instruments, consisting of financial swaps to manage the natural gas 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 financial 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 natural gas risk to varying degrees in the markets in which it serves retail, commercial and industrial customers. Approximately 66% of SouthStar's purchase instruments and 58% of its sales instruments are scheduled to mature in 2009 and the remaining 34% and 42%, respectively, in less than 2 years.

SouthStar also enters into both exchange and OTC derivative financial instruments to hedge natural gas 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 June 30, 2009, SouthStar's maximum exposure to any single OTC counterparty was $3 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 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 natural gas 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 96% of Sequent's purchase instruments and 97% of its sales instruments are scheduled to mature in less than 2 years and the remaining 4% and 3%, 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 $26 million during the six months ended June 30, 2009 and by $153 million during the six months ended June 30, 2008.

Energy Investments Golden Triangle Storage uses derivative financial instruments to reduce its exposure to the risk of changes in the prices of natural gas associated with natural gas to be purchased in future periods in connection with the construction of the storage caverns for pad gas, which includes volumes of non-working natural gas used to maintain the operational integrity of the caverns. 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 instruments.

Glossary

Table of Contents

We have designated all of Golden Triangle Storage's derivative financial instruments, consisting of financial swaps to manage the natural gas price risk associated with forecasted purchases of natural gas for its pad 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 pad gas is sold. Until the pad gas is sold, the gains and losses will remain in OCI since pad gas is considered to be a component of the caverns PP&E cost. Golden Triangle Storage currently has minimal hedge ineffectiveness. 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. Golden Triangle Storage began entering into derivative transactions during the second quarter of 2009 and these amounts were immaterial at June 30, 2009.

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 99-2, and accordingly these derivative financial instruments are not designated as derivatives or hedges under SFAS 133. SouthStar had no active weather derivatives at June 30, 2009 or 2008. As a result, our condensed consolidated balance sheets reflect no amounts for this hedging activity as of June 30, 2009 and at June 30, 2008; however, SouthStar did record a current asset of $4 million at December 31, 2008. SouthStar recognized losses on its weather derivative financial instruments, of $4 million for the six months ended June 30, 2009 and $5 million for the six months ended June 30, 2008 which was reflected in cost of gas on our condensed consolidated statements of income.

Quantitative Disclosures Related to Derivative Financial Instruments

As of June 30, 2009, our derivative financial instruments were comprised of both long and short natural gas positions, whereby a long position is a contract to purchase natural gas, and a short position is a contract to sell natural gas. As of June 30, 2009, we had net long natural gas contracts outstanding in the following quantities:

	Natural gas contracts (in Bcf)			
Hedge designation under SFAS 133	Distribution operations	Retail energy operations	Wholesale services	Consolidated
Cash flow	-	4	-	4
Not designated	17	8	99	124
Total	17	12	99	128

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 and six months ended June 30, 2009.

	Three months ended June 30, 2009		Six months ended June 30, 2009	
In millions	Retail energy operations	Wholesale services	Retail energy operations	Wholesale services
Designated as cash flow hedges under SFAS 133				
Natural gas contracts – loss reclassified from OCI into cost of gas for settlement of hedged item	$ (12)	$ -	$ (16)	$ -

Not designated as hedges under SFAS 133:				
Natural gas contracts – fair value adjustments recorded in operating revenues (1)	-	16	-	52
Natural gas contracts – fair value adjustments recorded in cost of gas (2)	-	-	(1)	-
Total (losses) gains on derivative instruments	$ (12)	$ 16	$ (17)	$ 52

(1) Associated with the fair value of existing derivative instruments at June 30, 2009.
(2) Excludes $4 million of losses recorded in cost of gas associated with weather derivatives accounted for in accordance with EITF 99-2 for the six months ended June 30, 2009.

In accordance with regulatory requirements, any realized gains and losses on derivative instruments used in our distribution operations segment are reflected in deferred natural gas costs within our condensed consolidated statements of financial position as indicated in the following table.

	Three months ended June 30,		Six months ended June 30,	
In millions	2009	2008	2009	2008
Elizabethtown Gas recognized (losses) gains on its derivative instruments reclassified to deferred natural gas costs	$ (7)	$ 8	$ (20)	$ 8

Glossary

Table of Contents

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 instruments, based upon the fair values of these financial instruments as of June 30, 2009:

In millions	Retail energy operations
Designated as hedges under SFAS 133	
Natural gas contracts – expected net loss reclassified from OCI into cost of gas for settlement of hedged item:	
Next twelve months	$ (18)
Thereafter	-
Total	$ (18)

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 June 30, 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 natural gas contracts	Derivative financial instruments assets and liabilities – current portion	$ -	$ 13	$ -	$ 13
Noncurrent natural gas contracts	Derivative financial instruments assets and liabilities	-	-	-	-
Liability Financial Instruments					
Current natural gas contracts	Derivative financial instruments assets and liabilities – current portion	-	(18)	-	(18)
Noncurrent natural gas contracts	Derivative financial instruments assets and liabilities	-	-	-	-
Total		-	(5)	-	(5)
Not designated as hedges under SFAS 133:					

Asset Financial Instruments					
Current natural gas contracts	Derivative financial instruments assets and liabilities – current portion	20	4	393	417
Noncurrent natural gas contracts	Derivative financial instruments assets and liabilities	1	-	63	64
Liability Financial Instruments					
Current natural gas contracts	Derivative financial instruments assets and liabilities – current portion	(20)	(4)	(368)	(392)
Noncurrent natural gas contracts	Derivative financial instruments assets and liabilities	(1)	-	(32)	(33)
Total		-	-	56	56
Total derivative financial instruments		$ -	$ (5)	$ 56	$ 51

(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 $124 million of cash collateral held on deposit in broker margin accounts as of June 30, 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.

Glossary

Table of Contents

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 June 30,	
In millions	2009	2008
Service cost	$ 2	$ 2
Interest cost	6	6
Expected return on plan assets	(8)	(8)
Amortization of prior service cost	-	-
Recognized actuarial loss	3	1
Net pension benefit cost	$ 3	$ 1

	Six months ended June 30,	
In millions	2009	2008
Service cost	$ 4	$ 4
Interest cost	13	13
Expected return on	(15)	(16)

plan assets		
Amortization of prior service cost	(1)	(1)
Recognized actuarial loss	5	2
Net pension benefit cost	$ 6	$ 2

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 six months of 2009, we made $17 million in contributions to our qualified plans. We expect to make additional contributions to our pension plans of $15 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 June 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. Effective January 1, 2006, benefits for prescription drugs were not provided under the plan to individuals who are eligible to receive prescription drug benefits under 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.

In millions	Three months ended June 30, 2009	Three months ended June 30, 2008
Service cost	$ -	$ 1
Interest cost	2	2
Expected return on plan assets	(1)	(2)
Amortization of prior service cost	(1)	(1)
Recognized actuarial loss	-	-
Net postretirement benefit cost	$ -	$ -

In millions	Six months ended June 30, 2009	Six months ended June 30, 2008
Service cost	$ -	$ 1
Interest cost	3	3
Expected return on plan assets	(2)	(3)
Amortization of prior service cost	(2)	(2)
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 $4 million in matching contributions to participant accounts in the first six months of 2009 and $3 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 currently allocated 75% to us and 25% to Piedmont except for earnings related to customers in Ohio and Florida, which are currently 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.

Stock-Based Compensation

In the first six 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 recast consolidated financial statements and related notes as filed on Form 8-K with the SEC on July 13, 2009, and in our Form 10-K for the year ended December 31, 2008, filed with the SEC on February 5, 2009.

Comprehensive Income

Our comprehensive income or loss 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. Our cumulative comprehensive income or loss that has been excluded from net income is reported as accumulated other comprehensive loss within our condensed consolidated statement of equity.

Glossary

Table of Contents

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 information on our various debt securities. For more information on our debt, see Note 6 in our recast consolidated financial statements and related notes as filed on Form 8-K with the SEC on July 13, 2009, and in our Form 10-K for the year ended December 31, 2008, filed with the SEC on February 5, 2009.

						Outstanding as of					
In millions	Year(s) due	Interest rate (1)		Weighted average interest rate(2)			June 30, 2009		Dec. 31, 2008		June 30, 2008
Short-term debt											
Commercial paper	2009	0.6	%	0.9	%	$	417	$	273	$	465
Credit Facilities	-	-		-			-		500		-
SouthStar line of credit	-	-		-			-		75		-
Sequent lines of credit (3)	-	-		-			-		17		38
Pivotal Utility line of credit	-	-		-			-		-		9
Capital leases	2009	4.9		4.9			1		1		1
Total short-term debt		0.6	%	1.0	%	$	418	$	866	$	513
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	0.1-5.3		1.3			200		200		161
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	$	1,637
Total debt		4.5	%	4.5	%	$	2,093	$	2,541	$	2,150

(1) As of June 30, 2009.
(2) For the six months ended June 30, 2009.
(3) In June 2009, Sequent's $25 million unsecured line of credit expired.

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 recast consolidated financial statements as filed on Form 8-K with the SEC on July 13, 2009, and in our Form 10-K for the year ended December 31, 2008, filed with the SEC on February 5, 2009.

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 June 30, 2009.

		Commitments due before December 31,	
In millions	Total	2009	2010 & thereafter
Standby letters of credit and performance and surety bonds	$ 23	$ 15	$ 8

Litigation

We are involved in litigation arising in the normal course of business. The ultimate resolution of such litigation is not expected to 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 recast consolidated financial statements as filed on Form 8-K with the SEC on July 13, 2009, and in our Form 10-K for the year ended December 31, 2008, filed with the SEC on February 5, 2009. 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.

Glossary

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. The plaintiffs appealed the dismissal of the lawsuit and, in May 2009, the Georgia Court of Appeals reversed the lower court’s order. In June 2009, GNG filed a petition for reconsideration with the Georgia Supreme Court and GNG is waiting to hear whether it will review the Court of Appeals’ decision. If the Court of Appeals’ decision is not reversed, the parties will proceed with the litigation at the trial court.

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, the plaintiffs appealed the decision but in June 2009, the plaintiffs withdrew their appeal of the courts dismissal order in exchange for GNG withdrawing and dropping all claims for attorney’s fees and costs in connection with the trial and appellate proceedings.

In May 2009, Pivotal Utility Holdings Inc., through its operating entity Elizabethtown Gas, was served as a responsible party, along with several hundred other entities, in litigation associated with the investigation and cleanup of the Passaic River and Newark Bay in New Jersey. The Plaintiffs, Maxus Energy Corporation and Tierra Solutions, Inc., who are among parties who have been ordered to address contamination in those water bodies, assert that historical operations of Elizabethtown Gas' former manufactured gas plants contributed to contamination at issue. We have not evaluated Plaintiffs' claims but do not believe that Elizabethtown Gas' historical operations would have had any significant impact in either the Passaic River or Newark Bay. At the present time, the Company cannot estimate the amount of any loss, if any, associated with this claim. In addition, we believe that any amounts associated with this claim would be subject to our Remediation Adjustment Clause that covers, subject to stated limitations, costs associated with environmental remediation cost investigation and cleanup.

Environmental Remediation Costs

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites.

Atlanta Gas Light We have identified ten former operating sites in Georgia and three sites of predecessor companies in Florida where the Company owned or operated all or part of these sites. We are required to investigate possible environmental contamination at those sites and, if necessary, clean up any contamination. As of December 31, 2008, the soil and sediment remediation program was complete for all Georgia sites, although groundwater cleanup continues. For elements of the program where we still cannot provide engineering cost estimates, considerable variability remains in future cost estimates. As of June 30, 2009 we have recorded a liability equal to the low end of the range of $56 million, an $18 million increase from December 31, 2008. Atlanta Gas Light expects $10 million to be incurred over the next 12 months.

Elizabethtown Gas We are associated with former sites in New Jersey, North Carolina and other states. Material cleanups of these sites have not been completed nor are precise estimates available for future cleanup costs and therefore considerable variability remains in future cost estimates. For the New Jersey sites, cleanup cost estimates range from $65 million to $110 million. As of June 30, 2009, we have recorded a liability equal to the low end of the range of $65 million, a $7 million increase from December 31, 2008. Elizabethtown Gas expects $7 million to be incurred over the next 12 months.

We also own a site in Elizabeth City, North Carolina that is subject to a remediation order by the North Carolina Department of Energy and Natural Resources. Cleanup cost estimates range from $12 million to $21 million. As of June 30, 2009, we had recorded a liability equal to the low end of the range of $12 million, a $2 million increase from December 31, 2008. We expect $2 million to be incurred over the next 12 months. There are currently no cost recovery mechanisms for the environmental remediation sites in North Carolina.

Glossary

Table of Contents

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 the FERC's capacity release posting and bidding requirements. In June 2009, we reached a settlement agreement with the FERC. This settlement agreement did not 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 (loss) before income taxes and net income (loss) attributable to AGL Resources Inc. for the three and six months ended June 30, 2009 and 2008.

	Three months ended June 30,	
In millions	2009	2008
Operating revenues	$ 377	$ 444
Operating expenses	322	438
Operating income	55	6
Other income	3	3
EBIT	58	9
Interest expense, net	(24)	(26)
Earnings (loss) before income taxes	34	(17)
Income tax expense (benefit)	13	(7)
Net income (loss)	21	(10)

Net income attributable to the noncontrolling interest	1	1
Net income (loss) attributable to AGL Resources Inc.	$ 20	$ (11)

	Six months ended June 30,	
In millions	2009	2008
Operating revenues	$ 1,372	$ 1,456
Operating expenses	1,087	1,262
Operating income	285	194
Other income	5	4
EBIT	290	198
Interest expense, net	(49)	(56)
Earnings before income taxes	241	142
Income tax expense	85	47
Net income	156	95
Net income attributable to the noncontrolling interest	17	17
Net income attributable to AGL Resources Inc.	$ 139	$ 78

Information by segment on our statement of financial position 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.

Glossary

Table of Contents

Summarized income statement information, identifiable and total assets, goodwill and property, plant and equipment expenditures as of and for the three and six months ended June 30, 2009 and 2008, by segment, are shown in the following tables.

Three months ended June 30, 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	$ 240	$ 125	$ 2	$ 10	$ -	$ 377
Intercompany revenues (1)	35	-	-	-	(35)	-
Total operating revenues	275	125	2	10	(35)	377
Operating expenses						
Cost of gas	85	102	-	-	(35)	152
Operation and maintenance	88	16	11	7	(3)	119
Depreciation and amortization	33	1	1	1	3	39
Taxes other than income taxes	9	1	1	-	1	12
Total operating expenses	215	120	13	8	(34)	322
Operating income (loss)	60	5	(11)	2	(1)	55
Other income	3	-	-	-	-	3
EBIT	$ 63	$ 5	$ (11)	$ 2	$ (1)	$ 58
Capital expenditures for property, plant and equipment	$ 89	$ 1	$ -	$ 17	$ 3	$ 110

Three months ended June 30, 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	$ 299	$ 177	$ (51)	$ 19	$ -	$ 444
Intercompany revenues (1)	46	-	-	-	(46)	-
Total operating revenues	345	177	(51)	19	(46)	444
Operating expenses						
Cost of gas	165	153	2	1	(46)	275
Operation and maintenance	83	16	10	6	(1)	114
Depreciation and amortization	31	1	2	2	2	38
Taxes other than income taxes	9	1	-	-	1	11
Total operating expenses	288	171	14	9	(44)	438
Operating income (loss)	57	6	(65)	10	(2)	6
Other income	-	-	-	-	3	3
EBIT	$ 57	$ 6	$ (65)	$ 10	$ 1	$ 9
Capital expenditures for property, plant and equipment	$ 64	$ 1	$ -	$ 18	$ 3	$ 86

Table of Contents

Six months ended June 30, 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	$ 812	$ 468	$ 70	$ 20	$ 2	$ 1,372
Intercompany revenues (1)	70	-	-	-	(70)	-
Total operating revenues	882	468	70	20	(68)	1,372
Operating expenses						
Cost of gas	440	361	9	-	(69)	741
Operation and maintenance	171	36	30	12	(5)	244
Depreciation and amortization	65	2	2	3	6	78
Taxes other than income taxes	18	1	2	1	2	24
Total operating expenses	694	400	43	16	(66)	1,087
Operating income (loss)	188	68	27	4	(2)	285
Other income	5	-	-	-	-	5
EBIT	$ 193	$ 68	$ 27	$ 4	$ (2)	$ 290
Identifiable and total assets (2)	$ 4,972	$ 182	$ 686	$ 386	$ (106)	$ 6,120
Goodwill	$ 404	$ -	$ -	$ 14	$ -	$ 418
Capital expenditures for property, plant and equipment	$ 158	$ 1	$ -	$ 40	$ 8	$ 207

Six months ended June 30, 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	$ 909	$ 552	$ (34)	$ 30	$ (1)	$ 1,456
Intercompany revenues (1)	112	-	-	-	(112)	-
Total operating revenues	1,021	552	(34)	30	(113)	1,456
Operating expenses						
Cost of gas	593	446	4	1	(112)	932
Operation and maintenance	169	35	22	10	(3)	233
Depreciation and amortization	62	2	3	3	4	74
Taxes other than income taxes	18	1	1	1	2	23
Total operating expenses	842	484	30	15	(109)	1,262
Operating income (loss)	179	68	(64)	15	(4)	194
Other income	1	-	-	-	3	4
EBIT	$ 180	$ 68	$ (64)	$ 15	$ (1)	$ 198
Identifiable and total assets (2)	$ 4,805	$ 253	$ 1,361	$ 306	$ (134)	$ 6,591
Goodwill	$ 406	$ -	$ -	$ 14	$ -	$ 420

Capital expenditures for property, plant and equipment	$ 123	$ 7	$ -	$ 29	$ 7	$ 166

(1) Intercompany revenues – wholesale services records its energy marketing and risk management revenues on a net basis, which includes intercompany revenues of $92 million and $303 million for the three months ended June 30, 2009 and 2008, respectively; and $257 million and $517 million for the six months ended June 30, 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.

Glossary

Note 9 – Subsequent Events

In May 2009, the FASB issued SFAS 165, which is effective for reporting periods ending after June 15, 2009. SFAS 165 establishes general standards of accounting for and disclosure of events that occur after the statement of financial position date, but before financial statements are issued, or are available to be issued. Prior to SFAS 165, guidance relating to subsequent events was contained in AU Section 560, “Subsequent Events,” (AU 560) of the auditing literature, which was primarily directed toward auditors, not management. SFAS 165 should be applied by management to the accounting for and disclosure of subsequent events, but does not apply to subsequent events or transactions that are within the scope of other applicable GAAP that provide different guidance. In accordance with SFAS 165, we evaluated subsequent events until the time that our financial statements were issued and filed with the SEC on July 30, 2009, and identified the following subsequent events.

In March 2009, Piedmont filed a lawsuit in the Court of Chancery of the State of Delaware against us asking the court to enter a judgment declaring that our right to purchase Piedmont’s ownership interest in SouthStar expires on November 1, 2009. We have reached a settlement agreement that will dismiss the lawsuit and will result in a restructuring of the ownership interests in the SouthStar joint venture. Under the terms of the agreement, which has been approved by the boards of directors of both companies, we will purchase an additional 15% ownership share in the joint venture from Piedmont for $58 million. As a result, we will own 85% of the SouthStar joint venture, and will be entitled to 85% of the annual earnings from the business, while Piedmont will retain the remaining 15% share. As part of the agreement, our interest will remain a noncontrolling interest and we will not have any further option rights to Piedmont’s remaining 15% ownership interest. The effective date of the transaction will be January 1, 2010, and the agreement is subject to approval by the Georgia Commission.

In July 2009, Atlanta Gas Light filed a request with the Georgia Commission to postpone its scheduled filing of a rate case in November 2009 until as late as June 2010. In July 2009, the Georgia Commission approved the request to postpone the filing until April 1, 2010, but no later than June 1, 2010.

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. As of June 30, 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 planning through the filing of rate cases and other regulatory requests 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 six months of 2009 relative to last year, a trend we expect to continue through 2009. For the six months ended June 30, 2009, our year-over-year consolidated utility customer growth rate was slightly negative or (0.3)%, compared to 0.3% positive growth 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.

Glossary

Table of Contents

Distribution Operations - regulatory planning

In 2010 and 2011, we expect to file base rate cases in three 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 (2)	Current rates effective until
Atlanta Gas Light (1)	Q2 2010	Q2 2010
Virginia Natural Gas	Q2 2010	Q3 2011
Chattanooga Gas	Q2 2010	Q1 2011

(1) In July 2009, Atlanta Gas Light filed a request with the Georgia Commission to postpone its scheduled filing of a rate case in November 2009. This request was approved by the Georgia Commission which agreed to postpone the filing until April 1, 2010, but no later than June 1, 2010.

(2) Subject to change.

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. Our initial request was an annual increase to base rates of $25 million. The filing also included energy conservation programs and a proposed Efficiency Usage and Adjustment mechanism (EUA), which is a form of decoupling, including weather normalization. If the EUA is approved, the current weather normalization clause would be suspended.

In June 2009 and in accordance with New Jersey rate case rules that require the filing of quarterly updates to a case, we filed a revised request for a $17 million annual increase to base rates. The primary driver of the reduced request was a revision to our depreciation rates. Our revised requested increase consists of:

- increased carrying costs associated with increased rate base ($9 million)
- increased operating expenses, including higher bad debt expenses and other ($5 million)
- increased return on equity from 10% to 11.25% and return on rate base from 7.95% to 8.41% ($3 million)

Distribution Operations - capital projects

In April 2009, the New Jersey Commission approved an accelerated $60 million enhanced infrastructure program for Elizabethtown Gas which is expected to start this year and be completed in 2011. This program was created in response to the New Jersey Governor's request for utilities to assist in the economic recovery by increasing infrastructure investments. 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. Elizabethtown Gas expects that approximately $20 million in capital expenditures for this program will occur in 2009.

In June 2009, Atlanta Gas Light filed a request for a Strategic Infrastructure Development and Enhancement (STRIDE) program with the Georgia Commission to upgrade its distribution system and liquefied natural gas facilities to improve system reliability and create a platform to meet operational flexibility needs and forecasted growth. Under the program, Atlanta Gas Light would be required to file a ten-year infrastructure plan every three years for review and approval by the Georgia Commission. Atlanta Gas Light is seeking approval of the initial three years of the program through 2012, which includes infrastructure improvements of approximately $176 million.

In July 2009, the Georgia Commission established a procedural schedule to consider our STRIDE program request. Under such schedule, we expect a decision by the end of this year. If approved, the program would merge with Atlanta Gas Light's existing Pipeline Replacement Program (PRP), which was initiated in 1998 and is scheduled to end in December 2013. Under the proposed STRIDE program, the existing $1.95 monthly PRP charge for residential customers would increase by 95 cents beginning in October 2009. Small commercial customers, who pay $5.85 per month under the current PRP rate design set by the Georgia Commission, would pay an additional $2.85 per month. The increased charges would be in effect subject to review and modification by the Georgia Commission every three years. For more information on Atlanta Gas Light's PRP program, see Note 1 in our recast consolidated financial statements and related notes as filed on Form 8-K with the SEC on July 13, 2009, and in our Form 10-K for the year ended December 31, 2008, filed with the SEC on February 5, 2009.

Retail Energy Operations

Our retail energy operations segment consists of SouthStar, a joint venture currently 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 33% market share based on customer count.

Glossary

Table of Contents

Although our ownership interest in the SouthStar partnership is currently 70%, the majority of SouthStar's earnings in Georgia are currently allocated, by contract, 75% to us and 25% to Piedmont. SouthStar’s earnings related to customers in Ohio and Florida are currently 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 and six months ended June 30, 2009, were largely at the 75% contractual rate.

In March 2009, Piedmont filed a lawsuit in the Court of Chancery of the State of Delaware against us asking the court to enter a judgment declaring that our right to purchase Piedmont’s ownership interest in SouthStar expires on November 1, 2009. We have reached a settlement agreement with Piedmont that will dismiss the lawsuit and will result in a restructuring of the ownership interests in the SouthStar joint venture. Under the terms of the agreement, which has been approved by the boards of directors of both companies, we will purchase an additional 15% ownership share in the joint venture from Piedmont for $58 million. As a result, we will own 85% of the SouthStar joint venture, and will be entitled to 85% of the annual earnings from the business, while Piedmont will retain the remaining 15% share. As part of the agreement, our interest will remain a noncontrolling interest and we will not have any further option rights to Piedmont’s remaining 15% ownership interest. The effective date of the transaction will be January 1, 2010, and the agreement is subject to approval by the Georgia Commission.

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, SouthStar continues to 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. Despite these efforts we have seen a 4% decline in average customer count and a 6% decline in market share for the six months ended June 30, 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 the Ohio and Florida markets, 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 United States. 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 United States 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.

Table of Contents

During the third quarter of 2008, Sequent negotiated an agreement for 0.04 Bcf 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 $4 million and $22 million during the three and six months ending June 30, 2009. There was no significant impact to VaR during these periods.

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.

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
Chattanooga Gas	March 2011	50% (A)
Elizabethtown Gas	March 2011	(A) (B)
Atlanta Gas Light	March 2012	up to 60% (A)
Virginia Natural Gas	March 2012	(A) (B)
Florida City Gas	March 2013	50%

(A) Includes aggregate annual minimum payments of $14 million for Atlanta Gas Light, Chattanooga Gas, Elizabethtown Gas and Virginia Natural Gas.

(B) Shared on a tiered structure.

Storage inventory outlook The following graph presents the NYMEX forward natural gas prices as of June 30, 2009, March 31, 2009 and December 31, 2008, for the period of July 2009 through June 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 United States economy, increasing natural gas supplies and above-average storage volumes, among other factors. These lower gas prices resulted 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 its inventory withdrawal schedule and forward natural gas prices at June 30, 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 $3.65)	Reservoir (WACOG $3.38)	Expected operating revenues (in millions)
2009			
Third quarter	1	7	$ 2
Fourth quarter	3	6	12
2010			
First quarter	-	5	8
Second quarter	-	1	1
Total	4	19	$ 23

Glossary

Table of Contents

If Sequent's storage withdrawals associated with existing inventory positions are executed as planned, it expects operating revenues from storage withdrawals of approximately $23 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 - Natural Gas 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 in our recast consolidated financial statements and related notes as filed on Form 8-K with the SEC on July 13, 2009, and in our Form 10-K for the year ended December 31, 2008, filed with the SEC on February 5, 2009. 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

Our Golden Triangle Storage project will consist of a new salt-dome storage facility in the Gulf Coast region of the U.S. with 12 Bcf of working natural gas capacity and total cavern capacity of 17 Bcf. In May 2008, Golden Triangle Storage started construction on both caverns. We expect the first cavern with 6 Bcf of working capacity to be in service in the third or fourth quarter of 2010 and the second cavern with 6 Bcf of working capacity to be in service 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 two caverns 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 49% 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 in the United States.

Corporate

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

We allocate substantially all of our corporate segment's operating expenses and interest costs to our operating segments in accordance with state regulations. Our corporate 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 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.

Glossary

Table of Contents

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.

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.

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 June 30, 2008, to provide comparisons of these items to December 31, 2008, and June 30, 2009.

Hedging Changes in natural gas 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 natural gas 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 financial 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 financial 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 financial 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.

Glossary

The following table sets forth a reconciliation of our operating margin and EBIT to our operating income, earnings (loss) before income taxes and net income (loss) attributable to AGL Resources Inc., together with other consolidated financial information for the three and six months ended June 30, 2009 and 2008.

In millions, except per share data	Three months ended June 30, 2009	2008	Change	Six months ended June 30, 2009	2008	Change
Operating revenues	$ 377	$ 444	$ (67)	$ 1,372	$ 1,456	$ (84)
Cost of gas	152	275	(123)	741	932	(191)
Operating margin (1)	225	169	56	631	524	107
Operating expenses	170	163	7	346	330	16
Operating income	55	6	49	285	194	91
Other income	3	3	-	5	4	1
EBIT (1)	58	9	49	290	198	92
Interest expense, net	24	26	(2)	49	56	(7)
Earnings (loss) before income taxes	34	(17)	51	241	142	99
Income tax expense (benefit)	13	(7)	20	85	47	38
Net income (loss)	21	(10)	31	156	95	61
Net income attributable to the noncontrolling interest	1	1	-	17	17	-
Net income (loss) attributable to AGL Resources Inc.	$ 20	$ (11)	$ 31	$ 139	$ 78	$ 61
Earnings (loss) per common share						
Basic – attributable to AGL Resources Inc. common shareholders	$ 0.26	$ (0.15)	$ 0.41	$ 1.81	$ 1.02	$ 0.79
Diluted – attributable to AGL Resources Inc. common shareholders	$ 0.26	$ (0.15)	$ 0.41	$ 1.81	$ 1.01	$ 0.80
Weighted-average number of common shares outstanding						
Basic	76.7	76.2	0.5	76.8	76.2	0.6
Diluted	76.9	76.2	0.7	76.9	76.4	0.5

(1) These are non-GAAP measurements.

For the second quarter of 2009, net income attributable to AGL Resources Inc. increased by $31 million and earnings per share attributable to AGL Resources Inc. increased by $0.41 per basic and diluted share compared to the same period last year. The variance between the two quarters was primarily the result of higher operating margins at distribution operations and wholesale services, offset by lower operating margins at energy investments. Additionally, this increase was offset by higher operating expenses due to increased environmental remediation costs, pension and postretirement benefit costs and depreciation expenses at distribution operations.

For the six months ended June 30, 2009, net income attributable to AGL Resources Inc. increased by $61 million and earnings per share attributable to AGL Resources Inc. increased by $0.79 per basic and $0.80 per diluted share compared to the same period last year. The variance between the two periods was primarily the result of higher operating margins at distribution operations and wholesale services offset by lower operating margins at energy investments and higher operating expenses primarily at wholesale services and distribution operations.

Glossary

Table of Contents

Selected weather, customer and volume metrics, which we consider to be some of the key performance indicators for our operating segments, for the three and six months ended June 30, 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 June 30, Normal	2009	2008	2009 vs. normal colder (warmer)	2009 vs. 2008 colder (warmer)	Six months ended June 30, Normal	2009	2008	2009 vs. normal colder (warmer)	2009 vs. 2008 colder (warmer)
Florida	17	21	18	24 %	17 %	349	390	215	12 %	81 %
Georgia	152	181	144	19 %	26 %	1,593	1,615	1,654	1 %	(2)%
Maryland	505	473	471	(6)%	-	3,015	3,085	2,810	2 %	10 %
New Jersey	501	473	475	(6)%	-	3,028	3,100	2,897	2 %	7 %
Tennessee	176	200	167	14 %	20 %	1,816	1,864	1,888	3 %	(1)%
Virginia	277	256	279	(8)%	(8)%	2,077	2,244	1,880	8 %	19 %

(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 2000 through 2009.

Customers	Three months ended June 30, 2009	2008	% change	Six months ended June 30, 2009	2008	% change
Distribution Operations						
Average end-use customers (in thousands)						
Atlanta Gas Light	1,565	1,574	(0.6)%	1,571	1,578	(0.4)%
Chattanooga Gas	62	62	-	62	62	-
Elizabethtown Gas	274	273	0.4 %	274	274	-
Elkton Gas	6	6	-	6	6	-
Florida City Gas	103	104	(1.0)%	103	104	(1.0)%
Virginia Natural Gas	272	272	-	274	273	0.4 %
Total	2,282	2,291	(0.4)%	2,290	2,297	(0.3)%
Operation and maintenance per customer	$ 39	$ 36	8 %	$ 75	$ 74	1 %
EBIT per customer	$ 28	$ 25	12 %	$ 84	$ 78	8 %

Retail Energy Operations						
Average customers in Georgia (in thousands)	510	535	(5)%	514	535	(4)%
Market share in Georgia	33 %	35 %	(6)%	33 %	35 %	(6)%

Volumes In billion cubic feet (Bcf)	Three months ended June 30, 2009	2008	% change	Six months ended June 30, 2009	2008	% change
Distribution Operations						
Firm	29	29	-	128	127	1 %
Interruptible	23	25	(8)%	49	54	(9)%
Total	52	54	(4)%	177	181	(2)%
Retail Energy Operations						
Georgia firm	5	5	-	23	24	(4)%
Ohio and Florida	2	1	100 %	7	3	133 %
Wholesale Services						
Daily physical sales (Bcf/day)	2.6	2.4	8 %	2.8	2.5	12 %

Glossary

Table of Contents

Second quarter 2009 compared to second 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 June 30, 2009 and 2008.

In millions	Operating revenues	Operating margin (1)	Operating expenses	EBIT (1)
2009				
Distribution operations	$ 275	$ 190	$ 130	$ 63
Retail energy operations	125	23	18	5
Wholesale services	2	2	13	(11)
Energy investments	10	10	8	2
Corporate (2)	(35)	-	1	(1)
Consolidated	$ 377	$ 225	$ 170	$ 58

In millions	Operating revenues	Operating margin (1)	Operating expenses	EBIT (1)
2008				
Distribution operations	$ 345	$ 180	$ 123	$ 57
Retail energy operations	177	24	18	6
Wholesale services	(51)	(53)	12	(65)
Energy investments	19	18	8	10
Corporate (2)	(46)	-	2	1
Consolidated	$ 444	$ 169	$ 163	$ 9

(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.

Operating margin Our operating margin for the second quarter of 2009 increased by $56 million or 33% compared to the same period last year. This increase was primarily due to increased operating margins at wholesale services and distribution operations, offset by lower operating margins at energy investments.

Distribution operations' operating margin increased by $10 million or 6% compared to last year. The following table indicates the significant changes in distribution operations' operating margin for the three months ended June 30, 2009 compared to the prior year period.

In millions	
	$ 180

Operating margin for second quarter of 2008	
Increased margins from gas storage carrying amounts at Atlanta Gas Light	4
Prior year revision in estimated unbilled natural gas volumes and slightly higher customer growth and usage at Elizabethtown Gas	4
Higher PRP revenues at Atlanta Gas Light	1
Other	1
Operating margin for second quarter of 2009	$ 190

Retail energy operations' operating margin decreased by $1 million or 4%. The following table indicates the significant changes in retail energy operations' operating margin for the three months ended June 30, 2009 compared to 2008.

In millions	
Operating margin for second quarter of 2008	$ 24
Higher contributions from the management of storage and transportation assets largely due to declining natural gas prices in 2009 offset by a prior year favorable pipeline rate order true-up	3
Lower operating margins in Ohio and Florida	(1)
Change in retail pricing plan mix and decrease in average number of customers	(3)
Operating margin for second quarter of 2009	$ 23

Wholesale services' operating margin increased $55 million compared to the second quarter of 2008 primarily due to $13 million 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 $55 million in reported hedge losses due to rising forward NYMEX natural gas prices and expanding transportation basis spreads in 2008. In addition, commercial activity decreased $13 million due to lower volatility in the marketplace during the quarter as compared to last year. The following table indicates the components of wholesale services' operating margin for the three months ended June 30, 2009 and 2008.

In millions	2009	2008
Commercial activity	$ (11)	$ 2
Gain (loss) on transportation hedges	11	(7)
Gain (loss) on storage hedges	2	(48)
Operating margin	$ 2	$ (53)

Energy investments' operating margin decreased by $8 million or 44% compared to last year. The following table indicates the significant changes in energy investments' operating margin for the three months ended June 30, 2009 compared to the prior year period.

In millions	
Operating margin for second quarter of 2008	$ 18
Decreased operating margin contribution at AGL Networks, primarily as a result of a network expansion project completed in 2008	(7)
Decreased interruptible margins at Jefferson Island	(1)
Operating margin for second quarter of 2009	$ 10

Operating expenses Our operating expenses for the second quarter of 2009 increased $7 million or 4% as compared to the second quarter of 2008. The following table indicates the significant changes in our operating expenses.

In millions	
Operating expenses for second quarter of 2008	$ 163
Increased environmental remediation costs at distribution operations	2
Increased pension and postretirement expenses at distribution operations	2
Increased depreciation expense at distribution operations and energy investments	2
Other	1
Operating expenses for second quarter of 2009	$ 170

Glossary

Interest expense Interest expense decreased by $2 million or 8% for the three months ended June 30, 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 June 30,		
In millions	2009	2008	Change
Average debt outstanding (1)	$ 1,996	$ 1,853	$ 143
Average rate	4.8 %	5.6 %	(0.8)%

(1) Daily average of all outstanding debt.

Six months 2009 compared to six months 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 six months ended June 30, 2009 and 2008.

In millions	Operating revenues	Operating margin (1)	Operating expenses	EBIT (1)
2009				
Distribution operations	$ 882	$ 442	$ 254	$ 193
Retail energy operations	468	107	39	68
Wholesale services	70	61	34	27
Energy investments	20	20	16	4
Corporate (2)	(68)	1	3	(2)
Consolidated	$ 1,372	$ 631	$ 346	$ 290

In millions	Operating revenues	Operating margin (1)	Operating expenses	EBIT (1)
2008				
Distribution operations	$ 1,021	$ 428	$ 249	$ 180
Retail energy operations	552	106	38	68
Wholesale services	(34)	(38)	26	(64)
Energy investments	30	29	14	15
Corporate (2)	(113)	(1)	3	(1)
Consolidated	$ 1,456	$ 524	$ 330	$ 198

(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.

Operating margin Our operating margin for the six months ended June 30, 2009, increased by $107 million or 20% compared to the same period last year. This increase was primarily due to increased operating margins at wholesale services and distribution operations, partially offset by lower operating margin at energy investments.

Distribution operations' operating margin increased by $14 million or 3% compared to last year. The following table indicates the significant changes in distribution operations' operating margin for the six months ended June 30, 2009 compared to 2008.

In millions	
Operating margin for six months of 2008	$ 428
Increased margins from gas storage carrying amounts at Atlanta Gas Light	7
Higher PRP revenues at Atlanta Gas Light	3
Prior year revision in estimated unbilled natural gas volumes at Elizabethtown Gas	3
All other, net	1
Operating margin for six months of 2009	$ 442

Retail energy operations' operating margin increased by $1 million or 1%. The following table indicates the significant changes in retail energy operations' operating margin for the six months ended June 30, 2009 compared to 2008.

In millions	
Operating margin for six months of 2008	$ 106
Higher contributions from the management of storage and transportation assets largely due to declining natural gas prices in 2009 offset by a prior year favorable pipeline rate order true-up	15
2008 pricing settlement with Georgia Commission	3
Higher operating margins in Ohio and Florida	2
Average customer usage	2
Change in retail pricing plan mix and decrease in average number of customers	(15)
Inventory LOCOM	(6)
Operating margin for six months of 2009	$ 107

Wholesale services' operating margin increased $99 million compared to the six months ended June 30, 2009, primarily due to $50 million 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 $70 million in reported hedge losses due to rising forward NYMEX natural gas prices and expanding transportation basis spreads in 2008. This increase was partially offset by a reduction in commercial activity of $18 million due to lower volatility in the marketplace during the period as compared to last year. In addition, the falling gas prices during the first quarter of 2009 required Sequent to record an $8 million LOCOM adjustment, net of $5 million of estimated hedging recoveries during the three months ended June 30, 2009. The following table indicates the components of wholesale services' operating margin for the six months ended June 30, 2009 and 2008.

In millions	2009	2008
Gain (loss) on transportation hedges	$ 32	$ (11)
Gain (loss) on storage hedges	18	(59)
Commercial activity	14	32
Inventory LOCOM, net of estimated hedging recoveries	(3)	-
Operating margin	$ 61	$ (38)

Glossary

Energy investments' operating margin decreased by $9 million or 31% compared to last year. The following table indicates the significant changes in energy investments' operating margin for the six months ended June 30, 2009 compared to 2008.

In millions	
Operating margin for six months of 2008	$ 29
Decreased operating margins at AGL Networks, primarily as a result of an expansion project completed in 2008	(7)
All other including slightly lower interruptible operating margins at Jefferson Island	(2)
Operating margin for six months of 2009	$ 20

Operating expenses Our operating expenses for the six months ended June 30, 2009, increased $16 million or 5% as compared to the same period last year. The following table indicates the significant changes in our operating expenses.

In millions	
Operating expenses for six months of 2008	$ 330
Increased incentive compensation costs at wholesale services and retail energy operations due to increased earnings	7
Increased depreciation expense primarily at distribution operations, retail energy operations and energy investments	4
Increased pension and postretirement expense at distribution operations	2
Increased environmental remediation costs at distribution operations	2
Increased bad debt expense at distribution operations	1
Increased legal expenses and other outside services related to Jefferson Island litigation	1
Decreased outside services, marketing and other expenses at distribution operations	(3)
Other	2
Operating expenses for six months of 2009	$ 346

Interest expense Interest expense decreased by $7 million or 13% for the six months ended June 30, 2009, primarily due to the decrease in short-term interest rates partially offset by higher average debt outstanding as indicated in the following table.

	Six months ended June 30,		
In millions	2009	2008	Change
Average debt outstanding (1)	$ 2,155	$ 1,933	$ 222
Average rate	4.5 %	5.8 %	(1.3)%

(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.

	Six months ended June. 30,	
In millions	2009	2008
Net cash provided by (used in):		
Operating activities	$ 731	$ 359
Investing activities	(207)	(166)
Financing activities	(528)	(193)
Net decrease in cash and cash equivalents	$ (4)	$ -

Cash Flow from Operating Activities In the first six months of 2009, our net cash flow provided from operating activities was $731 million, an increase of $372 million or 104% 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 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 $207 million for the six months ended June 30, 2009 and $166 million for the same period in 2008. The increase of $41 million or 25% in PP&E expenditures was primarily due to a $35 million increase at distribution operations, which included higher spending primarily for Virginia Natural Gas' Hampton Roads Crossing pipeline project connecting its northern and southern systems.

Glossary

Additionally, our energy investments' PP&E expenditures increased $11 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 June 30, 2009, our variable-rate debt was 28% of our total debt, compared to 29% as of June 30, 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 of fixed to floating debt.

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 June 30, 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 total capitalization calculation, as defined by our Credit Facilities was 53% at June 30, 2009 and 59% at December 31, 2008 and 56% at June 30, 2008. These amounts are within our required and targeted ranges. Our debt to total capitalization ratios as calculated from our condensed consolidated statements of financial position, as of the dates indicated, are summarized in the following table.

	June 30, 2009	Dec. 31, 2008	June 30, 2008
Short-term debt	11 %	20 %	13 %
Long-term debt	43	40	43
Total debt	54	60	56
Equity	46	40	44
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.”

Glossary

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.

Our short-term borrowings, as of June 30, 2009, decreased $95 million or 19% compared to the same period last year. This was primarily a result of reduced working capital requirements as a result of lower natural gas prices. This was offset by increased property, plant and equipment expenditures of $41 million and a $29 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 June 30, 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	$ 417
SouthStar line of credit (2)	74	-
Sequent lines of credit	5	-
Total	$ 1,219	$ 417

(1) Supported by our $1.0 billion and $140 million Credit Facilities, and includes $417 million of commercial paper borrowings.

(2) Capacity reduced by $1 million letter of credit.

Our commercial paper borrowings 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. As of June 30, 2009 and June 30, 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.

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 recast consolidated financial statements, as filed on Form 8-K with the SEC on July 13, 2009, and in our Form 10-K for the year ended December 31, 2008, filed with the SEC on February 5, 2009.

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 the first six months of 2009, we contributed $17 million to our pension plans. We expect to make additional contributions to our pension plans of $15 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.

Glossary

Table of Contents

The following table illustrates our expected future contractual obligation payments such as debt and lease agreements, and commitments and contingencies as of June 30, 2009.

In millions	Total	2009	2010 & 2011	2012 & 2013	2014 & thereafter
Recorded contractual obligations:					
Long-term debt	$ 1,675	$ -	$ 302	$ 241	$ 1,132
Short-term debt	418	418	-	-	-
PRP costs (1)	163	23	91	49	-
Environmental remediation liabilities (1)	133	10	43	53	27
Total	$ 2,389	$ 451	$ 436	$ 343	$ 1,159
Unrecorded contractual obligations and commitments (2):					
Pipeline charges, storage capacity and gas supply (3)	$ 1,705	$ 289	$ 690	$ 373	$ 353
Interest charges (4)	909	47	166	135	561
Operating leases	125	15	47	26	37
Asset management agreements (5)	33	8	23	2	-
Standby letters of credit, performance / surety bonds	23	15	7	1	-
Total	$ 2,795	$ 374	$ 933	$ 537	$ 951

(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 natural gas purchase commitments of 18 Bcf at floating gas prices calculated using forward natural gas prices as of June 30, 2009, and are valued at $73 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 June 30, 2009, and the maturity of the underlying debt instrument. As of June 30, 2009, we have $35 million of accrued interest on our consolidated statements of financial position that will be paid in over the next twelve months.
(5) Represent fixed-fee minimum payments for Sequent's asset management agreements.

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 recast Management's Discussion and Analysis of Financial Condition and Results of Operation as filed on Form 8-K with the SEC on July 13, 2009.

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 161 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 for 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.

Glossary

Table of Contents

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.

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, consolidated results of operations or cash flows.

Recently issued

SFAS 165 In May 2009, the FASB issued SFAS 165, which is effective for reporting periods ending after June 15, 2009. SFAS 165 establishes general standards of accounting for and disclosure of events that occur after the statement of financial position date, but before financial statements are issued, or are available to be issued. Prior to SFAS 165, guidance relating to subsequent events was contained in AU Section 560, “Subsequent Events,” (AU 560) of the auditing literature, which was primarily directed toward auditors, not management. SFAS 165 should be applied by management to the accounting for and disclosure of subsequent events, but does not apply to subsequent events or transactions that are within the scope of other applicable GAAP that provide different guidance. In accordance with SFAS 165, we have evaluated and disclosed in Note 9 subsequent events until the time that our financial statements were issued and filed with the SEC on July 30, 2009.

SFAS 166 In June 2009, the FASB issued SFAS 166, which amends FSP FAS 140-4, and requires improved disclosures about transfers of financial assets and removes the exception from applying FIN 46(R) to qualifying special purpose entities. SFAS 166 will be effective for us on January 1, 2010 and it will have no effect on our consolidated results of operations, cash flow and financial position.

SFAS 167 In June 2009, the FASB issued SFAS 167, which provides new consolidation guidance for variable interest entities (VIE). SFAS 167 requires a company to assess the determination of the primary beneficiary of a VIE based on whether the company has the power to direct matters that most significantly impact the activities of the VIE, and has the obligation to absorb losses or the right to receive benefits of the VIE. In addition, SFAS 167 requires ongoing reassessments of whether a company is the primary beneficiary of a VIE.

SFAS 167 will be effective for us beginning January 1, 2010. Earlier application is prohibited. We are currently evaluating the impact of this standard on our consolidated results of operations, cash flows and financial position.

SFAS 168 In June 2009, the FASB issued SFAS 168, which replaces SFAS 162. SFAS 168 creates a two-level GAAP hierarchy - authoritative and non-authoritative - and establishes the FASB’s Accounting Standards Codification (Codification) as the sole source of authoritative GAAP for non-governmental entities, except for rules and releases by the SEC.

After July 1, 2009, all non-grandfathered, non-SEC accounting guidance not included in the Codification is superseded and is deemed non-authoritative. SFAS 168 is effective for financial statements issued for interim and annual periods ending after September 15, 2009. SFAS 168 will have no impact on our consolidated results of operations, cash flows and financial position.

FSP FAS 157-4 This FSP establishes a two-step process to determine if the market for a financial asset is inactive and a transaction is not distressed. Step 1 provides factors that include, but are not limited to: transaction frequency, varying price quotations, index correlation, liquidity risk premiums, price spread increases and availability of public information. If a company determines the market is inactive, Step 2 must be applied.

In Step 2 an entity must presume that a quoted price is associated with a distressed transaction unless there was sufficient time before the measurement date to allow for usual and customary marketing activities, including multiple bidders. This FSP is effective for interim and annual periods ending after June 15, 2009. We adopted this FSP in the second quarter of 2009. Currently, this FSP does not effect us, as our financial assets are traded in active markets.

Glossary

Table of Contents

Item 3. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to risks associated with natural gas prices, interest rates and credit. Natural gas 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 natural gas 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.

Natural Gas Price Risk

Retail Energy Operations SouthStar's use of derivative 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 natural gas 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 natural gas prices. SouthStar uses these hedging instruments to lock in economic margins (as spreads between wholesale and retail natural gas 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 and six months ended June 30, 2009 and 2008, and provide details of the net fair value of derivative financial instruments outstanding as of June 30, 2009.

	Three months ended June 30,	
In millions	2009	2008
Net fair value of derivative financial instruments outstanding at beginning of period	$ (22)	$ 6
Derivative financial instruments realized or otherwise settled during period	17	(1)
Change in net fair value of derivative financial instruments	-	3
Net fair value of derivative financial instruments outstanding at end of period	(5)	8
Netting of cash collateral	15	(8)
Cash collateral and net fair value of derivative financial instruments outstanding at end of period	$ 10	$ -

	Six months ended June 30,	
In millions	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	18	(10)
Change in net fair value of derivative financial instruments	(6)	8
Net fair value of derivative financial instruments outstanding at end of period	(5)	8
Netting of cash collateral	15	(8)
Cash collateral and net fair value of derivative financial instruments outstanding at end of period	$ 10	$ -

The sources of SouthStar's net fair value of its natural gas-related derivative financial instruments at June 30, 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	$ (12)	$ -	$ -
2010	7	-	-
Total derivative financial instruments (2)	$ (5)	$ -	$ -

(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 instruments as of the dates indicated. SouthStar bases the average values on monthly averages for the six months ended June 30, 2009 and 2008.

In millions	Derivative financial instruments average fair values (1) at June 30, 2009	2008
Asset	$ 11	$ 7
Liability	28	1

(1) Excludes cash collateral amounts.

Glossary

Table of Contents

In millions	Derivative financial instruments fair values netted with cash collateral at June 30, 2009	Dec. 31, 2008	June 30, 2008
Asset	$ 10	$ 16	$ 5
Liability	-	2	5

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 six months ended June 30, 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 natural gas 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 six months ended June 30, 2009 and 2008.

In millions	Derivative financial instruments average values (1) at June 30, 2009	2008
Asset	$ 176	$ 48
Liability	84	78

(1) Excludes cash collateral amounts.

In millions	Derivative financial instruments fair values netted with cash collateral at June 30, 2009	Dec. 31, 2008	June 30, 2008
Asset	$ 183	$ 206	$ 90
Liability	18	27	85

Sequent experienced $26 million and $153 million decreases in the net fair value of its outstanding contracts during the first six months of 2009 and 2008, respectively, 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 and six months ended June 30, 2009 and 2008, and provide details of the net fair value of contracts outstanding as of June 30, 2009.

	Three months ended June 30,	
In millions	2009	2008
Net fair value of derivative financial instruments outstanding at beginning of period	$ 7	$ (18)
Derivative financial instruments realized or otherwise settled during period	33	5
Change in net fair value of derivative financial instruments	16	(83)
Net fair value of derivative financial instruments outstanding at end of period	56	(96)
Netting of cash collateral	109	101
Cash collateral and net fair value of derivative financial instruments outstanding at end of period	$ 165	$ 5

	Six months ended June 30,	
In millions	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	(78)	(45)
Change in net fair value of derivative financial instruments	52	(108)
Net fair value of derivative financial instruments outstanding at end of period	56	(96)
Netting of cash collateral	109	101
Cash collateral and net fair value of derivative financial instruments outstanding at end of period	$ 165	$ 5

The sources of Sequent's net fair value of its natural gas-related derivative financial instruments at June 30, 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	$ (65)	$ 89	$ -
2010 - 2011	(2)	27	-
2012 - 2014	1	6	-

Total derivative financial instruments (3)	$ (66)	$ 122	$ -

(1) Valued using NYMEX futures prices and other quoted sources.

(2) Valued using basis transactions that represent the cost to transport natural gas 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.

Glossary

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 natural gas 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 natural gas price 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 and six months ended June 30, 2009 and 2008 had the following VaRs.

	Three months ended June 30,		Six months ended June 30,	
In millions	2009	2008	2009	2008
Period end	$ 2.6	$ 2.3	$ 2.6	$ 2.3
Average	2.2	1.8	2.1	1.6
High	3.1	2.5	3.3	2.9
Low	1.7	1.2	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 $578 million of variable-rate debt, which includes $417 million of our variable-rate short-term debt and $161 million of variable-rate gas facility revenue bonds outstanding at June 30, 2009, a 100 basis point change in average market interest rates from 0.5% to 1.5% 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 June 30, 2009, Sequent's top 20 counterparties represented approximately 65% of the total counterparty exposure of $286 million, derived by adding together the top 20 counterparties' exposures and dividing by the total of Sequent's counterparties' exposures.

As of June 30, 2009, and June 30, 2008 Sequent's counterparties, or the counterparties' guarantors, had a weighted-average S&P equivalent credit rating of A, which is slightly improved from the credit rating of A- at December 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 is assigned an internal ratio, which is multiplied by their 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.

Glossary

Table of Contents

The following table shows Sequent's third-party natural gas contracts receivable and payable positions as of June 30, 2009 and 2008 and December 31, 2008.

	Gross receivables			Gross payables		
In millions	June 30, 2009	Dec. 31, 2008	June 30, 2008	June 30, 2009	Dec. 31, 2008	June 30, 2008
Netting agreements in place:						
Counterparty is investment grade	$ 207	$ 398	$ 590	$ 170	$ 266	$ 551
Counterparty is non-investment grade	12	15	37	39	41	40
Counterparty has no external rating	50	129	177	104	228	334
No netting agreements in place:						
Counterparty is investment grade	5	7	3	4	4	2
Counterparty is non-investment grade	2	-	-	-	-	-
Amount recorded on statements of financial position	$ 276	$ 549	$ 807	$ 317	$ 539	$ 927

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. If such collateral were not posted, Sequent's ability to continue transacting business with these counterparties would be impaired. If 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 $9 million at June 30, 2009, which would not have a material impact to our consolidated results of operations, cash flows or financial condition.

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 June 30, 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 June 30, 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.

Glossary

Table of Contents

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 us asking the court to enter a judgment declaring that our right to purchase Piedmont’s ownership interest in SouthStar expires on November 1, 2009. We have reached a settlement agreement with Piedmont that will dismiss the lawsuit and will result in a restructuring of the ownership interests in the SouthStar joint venture. Under the terms of the agreement, which has been approved by the boards of directors of both companies, we will purchase an additional 15% ownership share in the joint venture from Piedmont for $58 million. As a result, we will own 85% of the SouthStar joint venture, and will be entitled to 85% of the annual earnings from the business, while Piedmont will retain the remaining 15% share. As part of the agreement, our interest will remain a noncontrolling interest and we will not have any further option rights to Piedmont’s remaining 15% ownership interest. The effective date of the transaction will be January 1, 2010, and the agreement is subject to approval by the Georgia Commission.

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

There were no purchases of our common stock by us and any affiliated purchasers during the three months ended June 30, 2009.

Item 4. Submission of Matters to a Vote of Security Holders

The annual meeting of shareholders was held in Atlanta, Georgia on April 29, 2009. Holders of an aggregate of 77,086,652 shares of our common stock at the close of business on February 20, 2009, were entitled to vote at the meeting, of which 67,422,393 or 87.46% of the eligible voting shares were represented in person or by proxy. At the annual meeting, our shareholders were presented with three proposals, as set forth in our proxy statement. Our shareholders voted as follows:

Proposal 1 – Election of Directors

	For	Withheld
Charles R. Crisp	66,657,056	765,337
Wyck A. Knox, Jr.	66,480,924	941,469
Dennis M. Love	66,344,672	1,077,721
Charles H. McTier	66,595,675	826,718
Henry C. Wolf	66,683,058	739,335

The term of office of each of the following directors continued after the meeting: Sandra N. Bane, Thomas D. Bell, Jr., Arthur E. Johnson, Dean R. O'Hare, D. Raymond Riddle, James A. Rubright, John W. Somerhalder II, Felker W. Ward, Jr. and Bettina M. Whyte.

Proposal 2 – Amend our articles of incorporation to eliminate the classification of the board of directors.

For	65,838,999
Against	970,551
Abstain	612,843
Broker Non-Votes	-

Proposal 3 – Ratification of the appointment of PricewaterhouseCoopers LLP as our independent registered public accounting firm for 2009.

For	66,987,874
Against	158,500
Abstain	276,019
Broker Non-Votes	-

Item 6. Exhibits

3.1(a) Amended and Restated Articles of Incorporation filed November 2, 2005, with the Secretary of State of the state of Georgia (Exhibit 3.1, AGL Resources Inc. Form 8-K dated November, 2005).

3.1(b)

Articles of Amendment to the Amended and Restated Articles of Incorporation filed May 4, 2009, with the Secretary of State of the state of Georgia.

10 Third Amendment to Amended and Restated Limited Liability Company Agreement, dated July 29, 2009, by and between Georgia Natural Gas Company and Piedmont Energy Company.

12	Statement of Computation of Ratio of Earnings to Fixed Charges.
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.

Glossary

Table of Contents

SIGNATURE

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

AGL RESOURCES INC.
(Registrant)

Date: July 30, 2009 /s/ Andrew W. Evans
Executive Vice President, Chief Financial Officer and Treasurer

Glossary