AGL RESOURCES INC
Form 10-Q
November 07, 2014

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

FORM 10-Q

QUARTERLY REPORT PURSUANT TO SECTION 13 OF
THE SECURITIES EXCHANGE ACT OF 1934

For the Quarterly Period Ended September 30, 2014

Commission File Number 1-14174

AGL RESOURCES INC.
Ten Peachtree Place NE, Atlanta, Georgia 30309
404-584-4000

Georgia	58-2210952
(State of incorporation)	(I.R.S. Employer Identification No.)

AGL Resources Inc. (1) has filed all reports required to be filed by Section 13 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.

AGL Resources Inc. has submitted electronically and posted on its corporate website every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months.

AGL Resources Inc. is a large accelerated filer and is not a shell company.

The number of shares of AGL Resources Inc.’s common stock, $5.00 Par Value, outstanding as of October 31, 2014, was 119,572,999.

AGL RESOURCES INC.
Quarterly Report on Form 10-Q
For the Quarter Ended September 30, 2014

TABLE OF CONTENTS

		Page
Glossary of Key Terms		3
Item Number.		
	PART I - FINANCIAL INFORMATION	
1	Condensed Consolidated Financial Statements (Unaudited)	4
	Condensed Consolidated Statements of Financial Position	4
	Condensed Consolidated Statements of Income	5
	Condensed Consolidated Statements of Comprehensive Income	6
	Condensed Consolidated Statements of Equity	7
	Condensed Consolidated Statements of Cash Flows	8
	Notes to Condensed Consolidated Financial Statements (Unaudited)	9
	Note 1 - Organization and Basis of Presentation	9
	Note 2 - Significant Accounting Policies and Methods of Application	9
	Note 3 - Regulated Operations	14
	Note 4 - Fair Value Measurements	16
	Note 5 - Derivative Instruments	16
	Note 6 - Employee Benefit Plans	18
	Note 7 - Debt and Credit Facilities	19
	Note 8 - Equity	20
	Note 9 - Non-Wholly Owned Entities	21
	Note 10 - Commitments, Guarantees and Contingencies	22
	Note 11 - Segment Information	24
	Note 12 - Discontinued Operations	27
	Note 13 - Revision to Prior Period Financial Statements	28
2	Management’s Discussion and Analysis of Financial Condition and Results of Operations	32
	Forward-Looking Statements	32
	Executive Summary	32
	Results of Operations	36
	Liquidity and Capital Resources	42
	Critical Accounting Policies and Estimates	46
	Accounting Developments	46
3	Quantitative and Qualitative Disclosures About Market Risk	46
4	Controls and Procedures	49
	PART II - OTHER INFORMATION	
1	Legal Proceedings	50
1A	Risk Factors	50
2	Unregistered Sales of Equity Securities and Use of Proceeds	50
6	Exhibits	50

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GLOSSARY OF KEY TERMS

2013 Form 10-K	Our Annual Report on Form 10-K for the year ended December 31, 2013, filed with the SEC on February 6, 2014
2013 Form 10-K/A	Amendment No. 1 to our Annual Report on Form 10-K for the year ended December 31, 2013, filed with the SEC on November 7, 2014
AFUDC	Allowance for funds used during construction, which represents the estimated cost of funds, from both debt and equity sources, used to finance the construction of major projects, capitalized in PP&E and considered rate base for ratemaking purposes
AGL Capital	AGL Capital Corporation
AGL Credit Facility	$1.3 billion credit agreement entered into by AGL Capital to support its commercial paper program, which matures in November 2017
AGL Resources	AGL Resources Inc., together with its consolidated subsidiaries
Atlanta Gas Light	Atlanta Gas Light Company
Atlantic Coast Pipeline	Atlantic Coast Pipeline, LLC
Bcf	Billion cubic feet
Central Valley	Central Valley Gas Storage, LLC
Compass Energy	Compass Energy Services, Inc., which was sold in 2013
Dalton Pipeline	A 50% undivided ownership interest in a pipeline facility in Georgia
EBIT	Earnings before interest and taxes, the primary measure of our operating segments' profit or loss, which includes operating income and other income and excludes financing costs, including interest on debt and income tax expense
ERC	Environmental remediation costs
FASB	Financial Accounting Standards Board
Fitch	Fitch Ratings
GAAP	Accounting principles generally accepted in the United States of America
Georgia Commission	Georgia Public Service Commission, the state regulatory agency for Atlanta Gas Light
Golden Triangle	Golden Triangle Storage, Inc.
Heating Degree Days	A measure of the weather, calculated when the average daily temperatures are less than 65 degrees Fahrenheit
Heating Season	The period from November through March when natural gas usage and operating revenues are generally higher
Horizon Pipeline	Horizon Pipeline Company, LLC
Illinois Commission	Illinois Commerce Commission, the state regulatory agency for Nicor Gas
Jefferson Island	Jefferson Island Storage & Hub, LLC
LIFO	Last-in, first-out
LNG	Liquefied natural gas
LOCOM	Lower of weighted average cost or market price
Marketers	Marketers selling retail natural gas in Georgia and certificated by the Georgia Commission
MGP	Manufactured Gas Plant
Moody's	Moody's Investors Service
New Jersey BPU	New Jersey Board of Public Utilities, the state regulatory agency for Elizabethtown Gas
Nicor Gas	Northern Illinois Gas Company, doing business as Nicor Gas Company
Nicor Gas Credit Facility	$700 million credit facility entered into by Nicor Gas to support its commercial paper program, which matures in December 2017
NYMEX	New York Mercantile Exchange, Inc.
OCI	Other comprehensive income
Operating margin	

	A non-GAAP measure of income, calculated as operating revenues minus cost of goods sold and revenue tax expense
OTC	Over-the-counter
PBR	Performance-based rate
PennEast Pipeline	PennEast Pipeline Company, LLC
Piedmont	Piedmont Natural Gas Company, Inc.
Pivotal Home Solutions	Nicor Energy Services Company, doing business as Pivotal Home Solutions
PP&E	Property, plant and equipment
S&P	Standard & Poor's Ratings Services
Sawgrass Storage	Sawgrass Storage, LLC
SEC	Securities and Exchange Commission
Sequent	Sequent Energy Management, L.P.
SouthStar	SouthStar Energy Services, LLC
STRIDE	Atlanta Gas Light's Strategic Infrastructure Development and Enhancement program
Triton	Triton Container Investments, LLC
Tropical Shipping	Tropical Shipping and Construction Company Limited, and also the name used throughout this filing to describe the business operations of our former cargo shipping segment (excluding Triton), which has been classified as discontinued operations and held for sale
U.S.	United States
VaR	Value-at-risk is 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
VIE	Variable interest entity
Virginia Commission	Virginia State Corporation Commission, the state regulatory agency for Virginia Natural Gas
Virginia Natural Gas	Virginia Natural Gas, Inc.
WACOG	Weighted average cost of gas

PART I – FINANCIAL INFORMATION
Item 1. Condensed Consolidated Financial Statements (Unaudited)

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

		As of	
	September 30, 2014	December 31, 2013	September 30, 2013
In millions, except share amounts		Revised	Revised
Current assets			
Cash and cash equivalents	$32	$81	$97
Short-term investments	8	49	41
Receivables			
Energy marketing	544	786	502
Gas, unbilled and other	409	736	308
Less allowance for uncollectible accounts	37	29	32
Total receivables, net	916	1,493	778
Inventories, net	796	658	788
Regulatory assets	105	114	87
Derivative instruments	102	99	97
Assets held for sale	-	283	294
Other	134	118	70
Total current assets	2,093	2,895	2,252
Long-term assets and other deferred debits			
Property, plant and equipment	11,352	10,938	10,761
Less accumulated depreciation	2,427	2,295	2,281
Property, plant and equipment, net	8,925	8,643	8,480
Goodwill	1,827	1,827	1,822
Regulatory assets	637	705	845
Intangible assets	130	145	152
Other	341	335	259
Total long-term assets and other deferred debits	11,860	11,655	11,558
Total assets	$13,953	$14,550	$13,810
Current liabilities			
Short-term debt	$681	$1,171	$832
Energy marketing trade payables	612	671	539
Other accounts payable - trade	298	421	295
Current portion of long-term debt	200	-	-
Accrued expenses	173	203	149
Customer deposits and credit balances	122	136	140
Regulatory liabilities	118	183	174
Accrued environmental remediation liabilities	82	70	48
Derivative instruments	45	75	38
Liabilities held for sale	-	40	39
Other	131	148	153

Total current liabilities	2,462	3,118	2,407
Long-term liabilities and other deferred credits			
Long-term debt	3,605	3,813	3,816
Accumulated deferred income taxes	1,655	1,628	1,551
Regulatory liabilities	1,567	1,518	1,524
Accrued pension and retiree welfare benefits	406	404	511
Accrued environmental remediation liabilities	372	377	416
Other	84	79	79
Total long-term liabilities and other deferred credits	7,689	7,819	7,897
Total liabilities and other deferred credits	10,151	10,937	10,304
Commitments, guarantees and contingencies (see Note 10)			
Equity			
Common stock, $5 par value; 750,000,000 shares authorized: outstanding: 119,564,666 shares at September 30, 2014, 118,888,876 shares at December 31, 2013, and 118,778,298 shares at September 30, 2013	599	595	595
Additional paid-in capital	2,080	2,054	2,047
Retained earnings	1,222	1,063	1,042
Accumulated other comprehensive loss	(133)	(136)	(208)
Treasury shares, at cost: 216,523 shares at September 30, 2014, December 31, 2013, and September 30, 2013	(8)	(8)	(8)
Total common shareholders' equity	3,760	3,568	3,468
Noncontrolling interest	42	45	38
Total equity	3,802	3,613	3,506
Total liabilities and equity	$13,953	$14,550	$13,810

See Notes to Condensed Consolidated Financial Statements (Unaudited).

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

	Three months ended September 30,		Nine months ended September 30,	
In millions, except per share amounts	2014	2013 Revised	2014	2013 Revised
Operating revenues (includes revenue taxes of $9 and $103 for the three and nine months in 2014 and $9 and $83 for the three and nine months in 2013)	$589	$574	$3,940	$2,991
Operating expenses				
Cost of goods sold	198	174	2,000	1,447
Operation and maintenance	193	199	693	634
Depreciation and amortization	93	104	281	309
Taxes other than income taxes	30	27	160	139
Total operating expenses	514	504	3,134	2,529
Gain on disposition of assets	3	-	3	11
Operating income	78	70	809	473
Other income	3	7	8	18
Interest expense, net	(44)	(37)	(135)	(126)
Income before income taxes	37	40	682	365
Income tax expense	14	16	254	137
Income from continuing operations	23	24	428	228
(Loss) income from discontinued operations, net of tax	(31)	1	(80)	1
Net (loss) income	(8)	25	348	229
Less net income attributable to the noncontrolling interest	-	-	14	11
Net (loss) income attributable to AGL Resources Inc.	$(8)	$25	$334	$218
Per common share information				
Basic earnings (loss) per common share				
Continuing operations	$0.19	$0.20	$3.48	$1.85
Discontinued operations	(0.25)	0.01	(0.67)	0.01
Basic (loss) earnings per common share attributable to AGL Resources Inc. common shareholders	$(0.06)	$0.21	$2.81	$1.86
Diluted earnings (loss) per common share				
Continuing operations	$0.19	$0.20	$3.47	$1.84
Discontinued operations	(0.25)	0.01	(0.67)	0.01
Diluted (loss) earnings per common share attributable to AGL Resources Inc. common shareholders	$(0.06)	$0.21	$2.80	$1.85
Cash dividends declared per common share	$0.49	$0.47	$1.47	$1.41
Weighted average number of common shares outstanding				
Basic	119.0	118.2	118.8	117.8
Diluted	119.4	118.5	119.2	118.1

See Notes to Condensed Consolidated Financial Statements (Unaudited).

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

	Three months ended September 30,		Nine months ended September 30,	
In millions	2014	2013 Revised	2014	2013 Revised
Net (loss) income	$(8)	$25	$348	$229
Other comprehensive income (loss), net of tax				
Retirement benefit plans				
Reclassification of actuarial losses to net benefit cost (net of income tax of $2 and $5 for the three and nine months ended September 30, 2014, and $3 and $8 for the three and nine months ended September 30, 2013)	2	3	7	11
Reclassification of prior service credits to net benefit cost (net of income tax of $(1) for the nine months ended September 30, 2013)	-	(2)	(1)	(3)
Retirement benefit plans	2	1	6	8
Cash flow hedges, net of tax				
Net derivative instrument (losses) gains arising during the period	(2)	-	2	-
Reclassification of realized derivative instrument (gains) losses to net income (net of income tax of $(1) for the nine months ended September 30, 2014 and $1 for the nine months ended September 30, 2013)	-	-	(5)	2
Cash flow hedges, net	(2)	-	(3)	2
Other comprehensive income, net of tax	-	1	3	10
Comprehensive (loss) income	(8)	26	351	239
Less comprehensive income attributable to noncontrolling interest	-	-	14	11
Comprehensive (loss) income attributable to AGL Resources Inc.	$(8)	$26	$337	$228

See Notes to Condensed Consolidated Financial Statements (Unaudited).

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

	AGL Resources Inc. Shareholders							
	Common stock		Additional paid-in	Retained earnings	Accumulated other comprehensive	Treasury	Noncontrolling	Total
In millions, except per share amounts	Shares	Amount	capital	Revised	loss	shares	interest	Revised
Balance as of December 31, 2012	117.9	$ 590	$ 2,015	$ 990	$ (218)	$ (8)	$ 22	$ 3,391
Net income	-	-	-	218	-	-	11	229
Other comprehensive income	-	-	-	-	10	-	-	10
Dividends on common stock ($1.41 per share)	-	-	-	(166)	-	-	-	(166)
Contribution from noncontrolling interest	-	-	-	-	-	-	22	22
Distributions to noncontrolling interests	-	-	-	-	-	-	(17)	(17)
Stock granted, share-based compensation, net of forfeitures	-	-	(6)	-	-	-	-	(6)
Stock issued, dividend reinvestment plan	0.2	1	7	-	-	-	-	8
Stock issued, share-based compensation, net of forfeitures	0.7	4	22	-	-	-	-	26
Stock-based compensation expense, net of tax	-	-	9	-	-	-	-	9
Balance as of September 30, 2013	118.8	$ 595	$ 2,047	$ 1,042	$ (208)	$ (8)	$ 38	$ 3,506

	AGL Resources Inc. Shareholders							
	Common stock		Additional paid-in	Retained earnings	Accumulated other comprehensive	Treasury	Noncontrolling	Total

In millions, except per share amounts	Shares	Amount	capital	Revised	loss	shares	interest	Revised
Balance as of December 31, 2013	118.9	$ 595	$ 2,054	$ 1,063	$ (136)	$ (8)	$ 45	$ 3,613
Net income	-	-	-	334	-	-	14	348
Other comprehensive income	-	-	-	-	3	-	-	3
Dividends on common stock ($1.47 per share)	-	-	-	(175)	-	-	-	(175)
Distributions to noncontrolling interests	-	-	-	-	-	-	(17)	(17)
Stock granted, share-based compensation, net of forfeitures	-	-	(11)	-	-	-	-	(11)
Stock issued, dividend reinvestment plan	0.1	1	8	-	-	-	-	9
Stock issued, share-based compensation, net of forfeitures	0.6	3	19	-	-	-	-	22
Stock-based compensation expense, net of tax	-	-	10	-	-	-	-	10
Balance as of September 30, 2014	119.6	$ 599	$ 2,080	$ 1,222	$ (133)	$ (8)	$ 42	$ 3,802

See Notes to Condensed Consolidated Financial Statements (Unaudited).

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

	Nine months ended September 30,	
In millions	2014	2013 Revised
Cash flows from operating activities		
Net income	$ 348	$ 229
Adjustments to reconcile net income to net cash flow provided by operating activities		
Depreciation and amortization	281	309
(Loss) income from discontinued operations, net of taxes	80	(1)
Deferred income taxes	47	(32)
Change in derivative instrument assets and liabilities	(27)	37
Gain on disposition of assets	(3)	(11)
Changes in certain assets and liabilities		
Inventories	(138)	(89)
Receivables, other than energy marketing	335	359
Energy marketing receivables and trade payables, net	183	98
Income and miscellaneous taxes	(113)	75
Trade payables, other than energy marketing	(81)	(20)
Accrued/deferred natural gas costs	(65)	14
Other, net	37	82
Net cash flow (used) provided by operating activities of discontinued operations	(10)	20
Net cash flow provided by operating activities	874	1,070
Cash flows from investing activities		
Expenditures for property, plant and equipment	(543)	(526)
Acquisitions of assets	-	(154)
Disposition of assets	225	12
Other	47	16
Net cash flow used in investing activities of discontinued operations	(13)	(9)
Net cash flow used in investing activities	(284)	(661)
Cash flows from financing activities		
Net repayments of commercial paper	(490)	(545)
Dividends paid on common shares	(175)	(166)
Distribution to noncontrolling interest	(17)	(17)
Payment of senior notes	-	(225)
Issuance of senior notes	-	494
Contribution from noncontrolling interest	-	22
Other, net	19	28
Net cash flow used in financing activities	(663)	(409)
Net decrease in cash and cash equivalents - continuing operations	(50)	(11)
Net (decrease) increase in cash and cash equivalents - discontinued operations	(23)	11
Cash and cash equivalents (including held for sale) at beginning of period	105	131

Cash and cash equivalents (including held for sale) at end of period	32	131
Less cash and cash equivalents held for sale at end of period	-	34
Cash and cash equivalents (excluding held for sale) at end of period	$ 32	$ 97
Cash paid during the period for		
Interest	$ 150	$ 138
Income taxes	$ 317	$ 90
Non cash financing transaction		
Refinancing of gas facility revenue bonds	$ -	$ 200

See Notes to Condensed Consolidated Financial Statements (Unaudited).

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

Note 1 - Organization and Basis of Presentation

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,” the “company,” or “AGL Resources” mean consolidated AGL Resources Inc. and its subsidiaries.

The December 31, 2013, Condensed Consolidated Statement of Financial Position data was derived from our revised audited consolidated financial statements filed on November 7, 2014 but does not include all disclosures required by GAAP. We have prepared the accompanying unaudited Condensed Consolidated Financial Statements under the rules and regulations of the SEC. In accordance with such rules and regulations, we have condensed or omitted certain information and notes normally included in financial statements prepared in conformity with GAAP. Our unaudited 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. These unaudited Condensed Consolidated Financial Statements should be read in conjunction with our Consolidated Financial Statements and related notes included in Item 8 of our 2013 Form 10-K/A filed on November 7, 2014.

Due to the seasonal nature of our business and other factors, our results of operations and our financial condition for the periods presented are not necessarily indicative of the results of operations or financial condition to be expected for or as of any other period.

Basis of Presentation

Our unaudited Condensed Consolidated Financial Statements include our accounts, the accounts of our wholly owned subsidiaries, the accounts of our majority owned or otherwise controlled subsidiaries and the accounts of our consolidated VIE for which we are the primary beneficiary. For unconsolidated entities that we do not control, but exercise significant influence over, we use the equity method of accounting and our proportionate share of income or loss is recorded on the unaudited Condensed Consolidated Statements of Income. See Note 9 for additional information. We have eliminated intercompany profits and transactions in consolidation except for intercompany profits where recovery of such amounts is probable under the affiliates’ rate regulation process.

On September 1, 2014, we closed on the sale of Tropical Shipping, which historically operated within our cargo shipping segment. The assets and liabilities of these businesses are classified as held for sale on the unaudited Condensed Consolidated Statements of Financial Position, and the financial results of these businesses are reflected as discontinued operations on the unaudited Condensed Consolidated Statements of Income. Amounts shown in the following notes, unless otherwise indicated, exclude assets held for sale and discontinued operations. Cargo shipping also included our investment in Triton, which was not part of the sale and has been reclassified into our “other” segment. See Note 12 for additional information.

In the third quarter of 2014, we revised our financial statements and other affected disclosures for items related to the recognition of revenues for certain of our regulatory infrastructure programs and the amortization of our intangible assets. On November 7, 2014, we filed an amended Form 10-K/A revising certain prior period information with respect to our Annual Report on Form 10-K for the year ended December 31, 2013. See Note 13 for additional information.

Note 2 - Significant Accounting Policies and Methods of Application

Our accounting policies are described in Note 2 to our Consolidated Financial Statements and related notes included in Item 8 of our 2013 Form 10-K/A. Other than as described in Note 13, there were no significant changes to our accounting policies during the nine months ended September 30, 2014.

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. Our estimates are based on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Our estimates may involve 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. The most significant estimates relate to our rate-regulated subsidiaries, uncollectible accounts and other allowances for contingent losses, goodwill and other intangible assets, retirement plan benefit obligations, derivative and hedging activities and provisions for income taxes. We evaluate our estimates on an ongoing basis, and our actual results could differ from our estimates.

Cash and Cash Equivalents

Our cash and cash equivalents primarily consist of cash on deposit, money market accounts and certificates of deposit held by domestic subsidiaries with original maturities of three months or less. At December 31, 2013, and September 30, 2013, there were $24 million and $34 million, respectively, of cash and cash equivalents held by Tropical Shipping that were excluded from cash and cash equivalents within our unaudited Condensed Consolidated Statements of Financial Position and included in assets held for sale. For more information on the sale of Tropical Shipping, see Note 12.

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 that enable our wholesale services segment to net receivables and payables by counterparty upon settlement. Wholesale services also nets across product lines and against cash collateral, provided the master netting and cash collateral agreements include such provisions. While the amounts due from, or owed to, wholesale services' counterparties are settled net, they are recorded on a gross basis in our unaudited Condensed Consolidated Statements of Financial Position as energy marketing receivables and energy marketing payables.

Our wholesale services segment has trade and credit contracts that contain 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. To date, our credit ratings have exceeded the minimum requirements. As of September 30, 2014 and 2013, and December 31, 2013, the collateral that wholesale services would have been required to post if our credit ratings had been downgraded to non-investment grade status would not have had a material impact to our consolidated results of operations, cash flows or financial condition. If such collateral were not posted, wholesale services' ability to continue transacting business with these counterparties would be negatively impacted.

Inventories

For our regulated utilities, except Nicor Gas, our natural gas inventories and the inventories we hold for Marketers in Georgia are carried at cost on a WACOG basis. Nicor Gas' inventory is carried at cost on a LIFO basis. In Georgia's competitive environment, Marketers sell natural gas to firm end-use customers at market-based prices. Part of the unbundling process, which resulted from deregulation and provides this competitive environment, is the assignment to Marketers of certain pipeline services that Atlanta Gas Light has under contract. On a monthly basis, Atlanta Gas Light assigns the majority of the pipeline storage services that it has under contract to Marketers, along with a corresponding amount of inventory. Atlanta Gas Light also retains and manages a portion of its pipeline storage assets and related natural gas inventories for system balancing and to serve system demand. See Note 10 for information regarding a regulatory filing by Atlanta Gas Light related to natural gas inventory.

Our natural gas inventories at our retail operations, wholesale services and midstream operations segments carry inventory at the lower of cost or market value, where cost is determined on a WACOG basis. For these segments, we evaluate the weighted 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 value. For the three and nine months ended September 30, 2014, we recorded $5 million and $11 million, respectively, total LOCOM adjustment to reduce the value of our inventories to market value and $1 million and $9 million,

respectively, for the three and nine months ended September 30, 2013. Additionally, we have $19 million of inventory at wholesale services that is currently inaccessible due to operational issues at a third party storage facility. The owner of the storage facility is working to resolve these issues. While we expect this inventory to be fully recovered, the timing of withdrawal of this gas may be impacted by the operational issues.

At midstream operations, mechanical integrity tests and engineering studies are periodically performed on the storage facilities in accordance with certain state regulatory requirements. However, such tests may be performed in advance of such state requirements for operational purposes. During 2014, an engineering study and mechanical integrity tests were performed at one of our storage facilities, identifying a lower amount of working gas capacity that is the result of naturally occurring shrinkage of the storage caverns. Further, based on the lower capacity and an analysis of the volume of natural gas stored in the facility, we recorded natural gas costs to true-up the amount of retained fuel at this facility in the amount of $10 million for the nine months ended September 30, 2014. Our other storage facilities at midstream operations were not impacted.

Fair Value Measurements

We have financial and nonfinancial assets and liabilities subject to fair value measurement. The financial assets and liabilities measured and carried at fair value include cash and cash equivalents, and derivative assets and liabilities. The carrying values of receivables, short- and long-term investments, accounts payable, short-term debt, other current assets and liabilities, and accrued interest approximate fair value. Our nonfinancial assets and liabilities include pension and other retirement benefits, which are presented in Note 4 to our Consolidated Financial Statements and in related notes included in Item 8 of our 2013 Form 10-K/A.

As defined in the authoritative guidance related to fair value measurements and disclosures, 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 valuing 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 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 classify fair value balances based on the observance of those inputs in accordance with the fair value hierarchy.

Derivative Instruments

The fair value of the natural gas and weather derivative instruments that we use to manage exposures arising from changing natural gas prices and weather risk reflects the estimated amounts that we would receive or pay to terminate or close the contracts at the reporting date, taking into account the current unrealized gains or losses on open contracts. We use external market quotes and indices to value substantially all of our derivative instruments. See Note 4 and Note 5 for additional derivative disclosures.

Property, Plant and Equipment

On April 11, 2014, we entered into two arrangements associated with the Dalton Pipeline. The first was a construction and ownership agreement through which we will have a 50% undivided ownership interest in the 106 mile Dalton Pipeline that will be constructed in Georgia and serve as an extension of the Transco natural gas pipeline system into northwest Georgia. We also entered into an agreement to lease our 50% undivided ownership in the Dalton Pipeline once it is placed in-service. The lease payments to be received are $26 million annually for an initial term of 25 years. The lessee will be responsible for maintaining the pipeline during the lease term and for providing service to transportation customers under its FERC regulated tariff. Engineering design work has commenced and construction is expected to begin in the second quarter of 2016 with a targeted completion date in the second quarter of 2017. The capacity from this pipeline will further enhance system reliability as well as provide access to a more diverse supply of natural gas.

Goodwill

In 2014, we completed an engineering study at our midstream operations storage facilities that indicated a reduced forecast of working gas capacity from what was projected when our 2013 annual goodwill impairment analysis was performed during the fourth quarter of 2013. Given that the 2013 annual goodwill impairment test indicated that the estimated fair value of this reporting unit exceeded its carrying amount by less than 5%, we considered this reduced storage capacity as an indicator of potential impairment and accordingly conducted an interim goodwill impairment analysis during the first quarter of 2014.

The estimated fair value of this reporting unit was determined utilizing the income approach, which estimated the fair value based upon the present value of estimated future cash flows. The forecasts used in the income approach, which were updated during the first quarter of 2014 to reflect the contracting activity that occurred during the quarter, assume discrete period revenue growth through fiscal 2022 to reflect the recovery of subscription rates, stabilization of earnings and establishment of a reasonable base year that was used to estimate the terminal value in the valuation model. Consistent with our 2013 annual goodwill impairment testing, we assumed a long-term earnings growth rate in the terminal year of 2.5%, which we believe is appropriate given the current economic and industry-specific expectations. As of the valuation date, we utilized a discount rate of 7.0%, which we believe is appropriate as it reflects the relative risk and the time value of money, and is consistent with the peer group of this reporting unit as well as the discount rates that were utilized in our 2013 annual goodwill impairment tests.

Our interim goodwill impairment test assumed a cash flow forecast providing for growth over the next eight years. This forecast indicated that the estimated fair value of this reporting unit continues to exceed its carrying amount with a cushion of less than 10%. However, continued declines in capacity or subscription rates, reductions to our cash flow forecasts, a sustained period at the current subscription rates or other changes to the assumptions and factors used in this analysis may result in a future failure of step one of the goodwill impairment test and require us to proceed to step two of the goodwill impairment test in a future period.

The risk of impairment of the underlying long-lived assets is not estimated to be significant as the assets have long remaining useful lives, and authoritative guidance requires such assets to be tested for impairment on the basis of undiscounted cash flows over their remaining useful lives. We will continue to monitor this reporting unit for potential impairment. Our goodwill balances by segment as of September 30, 2014, and December 31, 2013, and changes in the amount of goodwill for the nine months ended September 30, 2013, are provided in the following table.

In millions	Distribution Operations	Retail Operations	Midstream Operations	Consolidated
December 31, 2012	$1,640	$122	$14	$ 1,776
2013 acquisitions	-	46	-	46
September 30, 2013 (1)	$1,640	$168	$14	$ 1,822
December 31, 2013 (1)	$1,640	$173	$14	$ 1,827
September 30, 2014	$1,640	$173	$14	$ 1,827

(1) Excludes goodwill at Tropical Shipping which is classified as held for sale. See Note 12 for additional information.

Other Income

Our other income is detailed in the following table.

	Three months ended September 30,		Nine months ended September 30,	
In millions	2014	2013	2014	2013
Equity method investment income (1)	$2	$3	$6	$8
AFUDC - equity	1	3	2	8
Other, net	-	1	-	2
Total other income	$3	$7	$8	$18

(1) For more information on our equity method investment income, see Note 9.

Earnings Per Common Share

We compute basic earnings per common share attributable to AGL Resources Inc. common shareholders by dividing our net income attributable to AGL Resources Inc. by the daily weighted average number of common shares outstanding. Diluted earnings per common share attributable to AGL Resources Inc. common shareholders reflect the potential reduction in earnings per common share attributable to AGL Resources Inc. common shareholders that occurs when potentially dilutive common shares are added to common shares outstanding.

We derive our potentially dilutive common shares by calculating the number of shares issuable under restricted stock, restricted stock units and stock options award programs. The vesting of certain shares of the restricted stock and restricted stock units depends on the satisfaction of defined performance and/or time-based criteria. The future issuance of shares underlying the outstanding stock options depends on whether the market price of the common shares underlying the options exceeds the respective exercise prices of the stock options. The following table shows the calculation of our diluted shares attributable to AGL Resources Inc. common shareholders for the periods presented, as if performance units currently earned under the plan ultimately vest and as if stock options currently exercisable at prices below the average market prices are exercised.

	Three months ended September 30,		Nine months ended September 30,	
In millions (except per share amounts)	2014	2013 (1)	2014 (1)	2013 (1)
Income from continuing operations (2)	$ 23	$ 24	$ 414	$ 217
(Loss) income from discontinued operations, net of tax (3)	(31)	1	(80)	1
Net (loss) income attributable to AGL Resources Inc.	$ (8)	$ 25	$ 334	$ 218
Denominator:				
Basic weighted average number of common shares outstanding (4)	119.0	118.2	118.8	117.8
Effect of dilutive securities	0.4	0.3	0.4	0.3
Diluted weighted average number of common shares outstanding	119.4	118.5	119.2	118.1
Basic earnings (loss) per common share				
From continuing operations	$ 0.19	$ 0.20	$ 3.48	$ 1.85
From discontinued operations	(0.25)	0.01	(0.67)	0.01
	$ (0.06)	$ 0.21	$ 2.81	$ 1.86

Basic (loss) earnings per common share attributable to AGL Resources Inc. common shareholders				
Diluted earnings (loss) per common share				
From continuing operations	$ 0.19	$ 0.20	$ 3.47	$ 1.84
From discontinued operations	(0.25)	0.01	(0.67)	0.01
Diluted (loss) earnings per common share attributable to AGL Resources Inc. common shareholders	$ (0.06)	$ 0.21	$ 2.80	$ 1.85

(1) Amounts revised and or include prior period adjustments. See Note 13 for additional information.

(2) Excludes net income attributable to the noncontrolling interest.

(3) For additional information on our discontinued operations, see Note 12.

(4) Daily weighted average shares outstanding.

Sale of Compass Energy

On May 1, 2013, we sold Compass Energy, a non-regulated retail natural gas business supplying commercial and industrial customers, which was part of our wholesale services segment. We received an initial cash payment of $12 million, which resulted in an $11 million pre-tax gain ($5 million net of tax) for the nine months ended September 30, 2013. Under the terms of the purchase and sale agreement, we were eligible to receive contingent cash consideration up to $8 million with a guaranteed minimum receipt of $3 million that was recognized during 2013. The remaining $5 million of contingent cash consideration was to be received from the buyer annually over a five-year earn-out period based upon the financial performance of Compass Energy. In the third quarter of 2014, we negotiated with the buyer to settle the future earn-out payments and we received $4 million, resulting in the recognition of a $3 million gain. We have a five year agreement to supply natural gas to our former customers. Accordingly, as a result of our continued involvement, the sale of Compass Energy did not meet the criteria for treatment as a discontinued operation.

Accounting Developments

On April 10, 2014, the FASB issued authoritative guidance related to reporting discontinued operations. The guidance generally raises the threshold for disposals to qualify as discontinued operations and requires new disclosures of both discontinued operations and certain other material disposals that do not meet the definition of a discontinued operation. The guidance will be effective for us prospectively beginning January 1, 2015. It is not expected to have a material impact on our consolidated financial statements, and it will have no impact on our accounting for the sale of Tropical Shipping.

On May 28, 2014, the FASB issued an update to authoritative guidance related to revenue from contracts with customers. The update replaces most of the existing guidance with a single set of principles for recognizing revenue from contracts with customers. The guidance will be effective for us beginning January 1, 2017. Early adoption is not permitted. The new guidance must be applied retrospectively to each prior period presented or via a cumulative effect upon the date of initial application. We have not yet determined the impact of this new guidance, nor have we selected a transition method.

On June 19, 2014, the FASB issued an update to authoritative guidance related to accounting for share-based payments when the terms of an award provide that a performance target could be achieved after the requisite service period. The guidance will be effective for us beginning January 1, 2016, and will have no material impact on our consolidated financial statements for our existing share-based plans.

Note 3 - Regulated Operations

We account for the financial effects of regulation in accordance with authoritative guidance related to regulated entities whose rates are designed to recover the costs of providing service. In accordance with this guidance, incurred costs and estimated future expenditures that would otherwise be charged to expense in the current period are capitalized as regulatory assets when it is probable that such costs or expenditures will be recovered in rates in the future. Similarly, we recognize regulatory liabilities when it is probable that regulators will require customer refunds through future rates or when revenue is collected from customers for estimated expenditures that have not yet been incurred. Generally, regulatory assets are amortized into expense, and regulatory liabilities are amortized into income over the period authorized by the regulatory commissions. The following table summarizes our regulatory assets and liabilities as of the dates presented.

In millions	September 30, 2014	December 31, 2013 (1)	September 30, 2013 (1)
Regulatory assets			
Recoverable ERC	$41	$45	$30
Recoverable pension and retiree welfare benefit costs	9	9	19
Recoverable seasonal rates	9	10	9
Deferred natural gas costs	3	1	-
Other	43	49	29
Total regulatory assets - current	105	114	87
Recoverable ERC	363	433	456
Recoverable pension and retiree welfare benefit costs	91	99	183
Long-term debt fair value adjustment	76	82	84
Recoverable regulatory infrastructure program costs (1)	62	55	78
Other	45	36	44
Total regulatory assets - long-term	637	705	845
Total regulatory assets	$742	$819	$932
Regulatory liabilities			
Bad debt over collection	$31	$41	$37
Accrued natural gas costs	29	92	104
Accumulated removal costs	27	27	17
Other	31	23	16
Total regulatory liabilities - current	118	183	174
Accumulated removal costs	1,499	1,445	1,448
Regulatory income tax liability	26	27	26
Unamortized investment tax credit	23	26	26
Bad debt over collection	7	17	20
Other	12	3	4
Total regulatory liabilities - long-term	1,567	1,518	1,524
Total regulatory liabilities	$1,685	$1,701	$1,698

(1) Amounts revised for prior period adjustments. See Note 13 for additional information.

Base rates are designed to provide the opportunity for both a recovery of cost and a return on investment during the period rates are in effect. As such, all of our regulatory assets recoverable through base rates are subject to review by the respective state regulatory commission during future rate proceedings. We believe that we will be able to recover such costs consistent with our historical recoveries.

Unrecognized Ratemaking Amounts We have authorized unrecognized ratemaking amounts that are not reflected within our unaudited Condensed Consolidated Statements of Financial Position as indicated in the following table. These amounts are primarily composed of an allowed equity rate of return on assets associated with certain of our regulatory infrastructure programs. These amounts will be recognized as revenues in our financial statements in the periods they are collected in rates from our customers. For additional information, see Note 13.

In millions	
September 30, 2014	$118
December 31, 2013	$93
September 30, 2013	$86

Natural Gas Costs We charge our utility customers for natural gas consumed using natural gas cost recovery mechanisms established by the state regulatory agencies. Under these mechanisms, all prudently incurred natural gas costs are passed through to customers without markup, subject to regulatory review. We defer or accrue the difference between the actual cost of gas and the amount of commodity revenue earned in a given period, such that no operating margin is recognized related to these costs. The deferred or accrued amount is either billed or refunded to our customers prospectively through adjustments to the commodity rate. Deferred natural gas costs are reflected as regulatory assets and accrued natural gas costs are reflected as regulatory liabilities. The following table illustrates the change in net position of these costs from September 30, 2013 to September 30, 2014.

In millions	September 30, 2014	September 30, 2013	Change
Deferred natural gas costs	$3	$-	$3
Accrued natural gas costs	(29)	(104)	75
Total (1)	$(26)	$(104)	$78

(1) The $78 million change resulted from increased natural gas prices during the first nine months of 2014 compared to the first nine months of 2013, primarily driven by colder weather experienced in 2014.

Environmental Remediation Costs We are subject to federal, state and local laws and regulations governing environmental quality and pollution control that require us to remove or remedy the effect on the environment of the disposal or release of specified substances at our current and former operating sites, substantially all of which is related to our MGP sites. The ERC assets and liabilities are associated with our distribution operations segment and remediation costs are generally recoverable from customers through rate mechanisms approved by regulators. Accordingly, both costs incurred to remediate the former MGP sites, plus the future estimated cost recorded as liabilities, net of amounts previously collected, are recognized as a regulatory asset until recovered from customers.

Our ERC liabilities are estimates of future remediation costs for investigation and cleanup of our current and former operating sites that are contaminated. These estimates are based on conventional engineering estimates and the use of probabilistic models of potential costs when such estimates cannot be made, on an undiscounted basis. As cleanup options and plans mature and cleanup contracts are entered into, we are increasingly able to provide conventional engineering estimates of the likely costs of many elements of the remediation program. These estimates contain various engineering assumptions, which we refine and update on an ongoing basis. These liabilities do not include other potential expenses, such as unasserted property damage claims, personal injury or natural resource damage claims, legal expenses or other costs for which we may be held liable but for which we cannot reasonably estimate an amount. The following table provides additional information on the costs related to remediation of our current and former operating sites as of September 30, 2014 and reflects changes in estimates since December 31, 2013.

In millions	Probabilistic model cost estimates	Engineering estimates	Amount recorded		Expected costs over next 12 months
Illinois	$205 - $462	$46	$244		$41
New Jersey	107 - 174	16	122		16
Georgia and Florida	66 - 106	9	77		17
North Carolina (1)	n/a	11	11		8
Total	$378 - $742	$82	$454	(2)	$82

(1) We have no regulatory recovery mechanisms for the site in North Carolina. Therefore, there is no amount included within our regulatory assets and changes in estimated costs are recognized in income in the period of change.

(2) Increase of $7 million from December 31, 2013, primarily relates to a scope increase required by the Georgia Environmental Protection Division for a site in Georgia and an adjustment for a site in Florida. This was partially offset by a decrease for a site in New Jersey where remediation is almost complete.

In July 2014, we reached a $77 million settlement with an insurance company for environmental claims relating to potential contamination at several of our MGP sites in New Jersey and North Carolina. The terms of the settlement required the $77 million to be paid in two installments. We received the first $45 million installment in the third quarter of 2014 and this payment was primarily recorded as a reduction to our recoverable ERC regulatory asset. The remaining $32 million is due in the third quarter of 2015. We will file for approval with the New Jersey BPU to utilize the insurance proceeds related to the New Jersey sites to reduce the ERC expenditures that otherwise would have been recovered from our customers in future periods. As such, the settlement, once approved, is expected to reduce our recoverable ERC regulatory asset and have a favorable impact on the rates for our Elizabethtown Gas customers.

Note 4 - Fair Value Measurements

The methods used to determine the fair values of our assets and liabilities are described within Note 2.

Derivative Instruments

The following table summarizes, by level within the fair value hierarchy, our derivative assets and liabilities that were carried at fair value on a recurring basis in our unaudited Condensed Consolidated Statements of Financial Position as of the dates presented. See Note 5 for additional derivative instrument information.

	September 30, 2014		December 31, 2013		September 30, 2013	
In millions	Assets (1)	Liabilities	Assets (1)	Liabilities	Assets (1)	Liabilities
Natural gas derivatives						
Quoted prices in active markets (Level 1)	$4	$(72)	$6	$(79)	$4	$(52)
Significant other observable inputs (Level 2)	57	(51)	67	(79)	60	(41)
Netting of cash collateral	49	76	43	78	45	49
Total carrying value (2) (3)	$110	$(47)	$116	$(80)	$109	$(44)

(1) Balances of $3 million at September 30, 2014, December 31, 2013 and September 30, 2013, associated with certain weather derivatives have been excluded, as they are accounted for based on intrinsic value rather than fair value.

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

(3) There were no significant transfers between Level 1, Level 2 or Level 3 for any of the dates presented.

Debt

Our long-term debt is recorded at amortized cost, with the exception of Nicor Gas' first mortgage bonds, which are recorded at their acquisition date fair value. The fair value adjustment of Nicor Gas' first mortgage bonds is being amortized over the lives of the bonds. The following table lists the carrying amount and fair value of our long-term debt as of the dates presented.

In millions	September 30, 2014	December 31, 2013	September 30, 2013
Long-term debt carrying amount	$3,805	$3,813	$3,816
Long-term debt fair value (1)	4,165	3,956	4,024

(1) Fair value determined using Level 2 inputs.

Note 5 - Derivative Instruments

A description of our objectives and strategies for using derivative instruments, related accounting policies and methods used to determine their fair values are described in Note 2 to our Consolidated Financial Statements and related notes included in Item 8 of our 2013 Form 10-K/A. See Note 4 for additional fair value disclosures.

Certain of our derivative instruments contain credit risk-related or other contingent features that could require us to post collateral in the normal course of business when our financial instruments are in net liability positions. As of September 30, 2014, for agreements with such features, derivative instruments with liability fair values for which we had posted no collateral to our counterparties totaled $47 million. The maximum collateral that could be required with

these features is $10 million. For more information, see “Energy Marketing Receivables and Payables” in Note 2, which also have credit risk-related or other contingent features. Our derivative instrument activities are included within operating cash flows as an increase (decrease) to net income of $(27) million and $37 million for the nine months ended September 30, 2014 and 2013, respectively. See Note 4 for additional derivative instrument information. The following table summarizes the various ways in which we account for our derivative instruments and the impact on our unaudited Condensed Consolidated Financial Statements.

	Recognition and Measurement	
Accounting Treatment	Statements of Financial Position	Statements of Income
Cash flow hedge	Derivative carried at fair value	Ineffective portion of the gain or loss on the derivative instrument is recognized in earnings
	Effective portion of the gain or loss on the derivative instrument is reported initially as a component of accumulated OCI (loss)	Effective portion of the gain or loss on the derivative instrument is reclassified out of accumulated OCI (loss) and into earnings when the hedged transaction affects earnings
Fair value hedge	Derivative carried at fair value	Gains or losses on the derivative instrument and the hedged item are recognized in earnings. As a result, to the extent the hedge is effective, the gains or losses will offset and there is no impact on earnings. Any hedge ineffectiveness will impact earnings
	Changes in fair value of the hedged item are recorded as adjustments to the carrying amount of the hedged item	
Not designated as hedges	Derivative carried at fair value	Realized and unrealized gains or losses on the derivative instrument are recognized in earnings
	Distribution operations’ gains and losses on derivative instruments are deferred as regulatory assets or liabilities until included in cost of goods sold	Gains or losses on these derivative instruments are ultimately included in billings to customers and are recognized in cost of goods sold in the same period as the related revenues

Quantitative Disclosures Related to Derivative Instruments

As of the dates presented, our derivative instruments were comprised of both long and short natural gas positions. A long position is a contract to purchase natural gas, and a short position is a contract to sell natural gas. We had a net long natural gas contracts position outstanding in the following quantities:

In Bcf (1)	September 30, 2014 (2)	December 31, 2013	September 30, 2013
Cash flow hedges	7	6	3
Not designated as hedges	97	183	40
Total volumes	104	189	43
Short position	(2,756)	(2,622)	(2,788)
Long position	2,860	2,811	2,831
Net long position	104	189	43

(1) Volumes related to Nicor Gas exclude variable-priced contracts, which are carried at fair value, but whose fair values are not directly impacted by changes in commodity prices.

(2) Approximately 98% of these contracts have durations of 2 years or less and the remaining 2% expire between 2 and 5 years.

Derivative Instruments in our Unaudited Condensed Consolidated Statements of Financial Position

In accordance with regulatory requirements, gains and losses on derivative instruments used to hedge natural gas purchases for customer use at distribution operations are reflected in accrued natural gas costs within our Consolidated Statements of Financial Position until billed to customers. The following amounts deferred as a regulatory asset or liability on our unaudited Condensed Consolidated Statements of Financial Position represent the net realized gains (losses) related to these natural gas cost hedges for the periods presented.

In millions	Three months ended September 30, 2014	Three months ended September 30, 2013	Nine months ended September 30, 2014	Nine months ended September 30, 2013
Nicor Gas	$(4)	$(6)	$8	$2
Elizabethtown Gas	(1)	(1)	4	(5)

The following table presents the fair values and unaudited Condensed Consolidated Statements of Financial Position classifications of our derivative instruments as of the dates presented.

In millions	Classification	September 30, 2014 Assets	September 30, 2014 Liabilities	December 31, 2013 Assets	December 31, 2013 Liabilities	September 30, 2013 Assets	September 30, 2013 Liabilities
Designated as cash flow or fair value hedges							
Natural gas contracts	Current	$ 2	$ (2)	$ 3	$ (1)	$ 6	$ (5)
Not designated as hedges							
Natural gas contracts	Current	834	(891)	691	(761)	445	(462)
Natural gas contracts	Long-term	78	(80)	206	(220)	143	(153)

Total	912	(971)	897	(981)	588	(615)
Gross amount of recognized assets and liabilities (1) (2)	914	(973)	900	(982)	594	(620)
Gross amounts offset in our unaudited Condensed Consolidated Statements of Financial Position (2)	(801)	926	(781)	902	(482)	576
Net amounts of assets and liabilities presented in our unaudited Condensed Consolidated Statements of Financial Position (3)	$ 113	$ (47)	$ 119	$ (80)	$ 112	$ (44)

(1) The gross amounts of recognized assets and liabilities are netted within our unaudited Condensed Consolidated Statements of Financial Position to the extent that we have netting arrangements with the counterparties.

(2) As required by the authoritative guidance related to derivatives and hedging, the gross amounts of recognized assets and liabilities above do not include cash collateral held on deposit in broker margin accounts of $125 million as of September 30, 2014, $121 million as of December 31, 2013, and $94 million as of September 30, 2013. Cash collateral is included in the “Gross amounts offset in our unaudited Condensed Consolidated Statements of Financial Position” line of this table.

(3) At September 30, 2014, December 31, 2013, and September 30, 2013, we held letters of credit from counterparties that would offset, under master netting arrangements, an insignificant portion of these assets.

Derivative Instruments in the Unaudited Condensed Consolidated Statements of Income

The following table presents the impacts of our derivative instruments in our unaudited Condensed Consolidated Statements of Income for the periods presented.

	Three months ended September 30,		Nine months ended September 30,	
In millions	2014	2013	2014	2013
Designated as cash flow or fair value hedges				
Natural gas contracts - net gain reclassified from OCI into cost of goods sold	$(1)	$(1)	$4	$-
Natural gas contracts - net gain reclassified from OCI into operation and maintenance expense	1	-	2	-
Interest rate swaps - net loss reclassified from OCI into interest expense	-	1	-	(2)
Income tax benefit	-	-	(1)	1
Net of tax	-	-	5	(1)
Not designated as hedges (1)				
Natural gas contracts - net fair value adjustments recorded in operating revenues	(6)	(14)	(6)	(16)
Natural gas contracts - net fair value adjustments recorded in cost of goods sold (2)	(1)	-	-	(1)
Income tax benefit	2	5	2	7
Net of tax	(5)	(9)	(4)	(10)
Total (losses) gains on derivative instruments	$(5)	$(9)	$1	$(11)

(1) Associated with the fair value of derivative instruments held at September 30, 2014 and 2013.

(2) Excludes losses recorded in cost of goods sold associated with weather derivatives of $6 million and $3 million for the nine months ended September 30, 2014 and 2013, respectively.

Any amounts recognized in operating income related to ineffectiveness or due to a forecasted transaction that is no longer expected to occur were immaterial for the three and nine months ended September 30, 2014 and 2013. Our expected gains to be reclassified from OCI into cost of goods sold, operation and maintenance expense, interest expense and operating revenues and recognized in our unaudited Condensed Consolidated Statements of Income over the next 12 months are less than $1 million. These deferred gains and losses are related to natural gas derivative contracts associated with retail operations and Nicor Gas' system use. The expected gains are based upon the fair values of these financial instruments at September 30, 2014. The effective portion of gains and losses on derivative instruments qualifying as cash flow hedges that were recognized in OCI during the periods is presented on our unaudited Condensed Consolidated Statements of Income. See Note 8 for these amounts.

There have been no other significant changes to our derivative instruments, as described in Note 2, Note 4 and Note 5 to our Consolidated Financial Statements and related notes included in Item 8 of our 2013 Form 10-K/A.

Note 6 - Employee Benefit Plans

Pension Benefits

We sponsor the AGL Resources Inc. Retirement Plan, a tax-qualified defined benefit retirement plan for our eligible employees, which is described in Note 6 to our Consolidated Financial Statements and related notes included in Item 8

of our 2013 Form 10-K/A. Following are the components of our pension costs for the periods indicated.

	Three months ended September 30,		Nine months ended September 30,	
In millions	2014	2013	2014	2013
Service cost	$6	$7	$18	$22
Interest cost	12	11	35	32
Expected return on plan assets	(16)	(16)	(48)	(47)
Net amortization of prior service cost	(1)	-	(2)	(1)
Recognized actuarial loss	5	9	16	26
Net periodic pension benefit cost	$6	$11	$19	$32

Welfare Benefits

The benefits of our Health and Welfare Plan for Retirees and Inactive Employees of AGL Resources Inc. (AGL Welfare Plan) are described in Note 6 to our Consolidated Financial Statements and related notes included in Item 8 of our 2013 Form 10-K/A. Following are the components of our welfare costs for the periods indicated.

	Three months ended September 30,		Nine months ended September 30,	
In millions	2014	2013	2014	2013
Service cost	$1	$1	$2	$2
Interest cost	4	3	11	10
Expected return on plan assets	(2)	(1)	(5)	(4)
Net amortization of prior service cost	(1)	(1)	(2)	(3)
Recognized actuarial loss	1	2	4	6
Net periodic welfare benefit cost	$3	$4	$10	$11

Note 7 - Debt and Credit Facilities

The following table provides maturity dates, year-to-date weighted average interest rates and amounts outstanding for our various debt securities and facilities for the periods presented. We fully and unconditionally guarantee all debt issued by AGL Capital. For additional information on our debt, see Note 8 in our Consolidated Financial Statements and related notes in Item 8 of our 2013 Form 10-K/A.

		September 30, 2014		September 30, 2013			
Dollars in millions	Year(s) due	Weighted average interest rate (1)	Outstanding	Outstanding at December 31, 2013	Weighted average interest rate (1)		Outstanding
Short-term debt							
Commercial paper - AGL Capital (2)	2014	0.3 %	$ 292	$ 857	0.4	%	$ 680
Commercial paper - Nicor Gas (2)	2014	0.2	389	314	0.3		152
Total short-term debt		0.3 %	$ 681	$ 1,171	0.4	%	$ 832
Current portion of long-term debt	2015	5.0 %	$ 200	$ -	-		$ -
Long-term debt - excluding current portion							
Senior notes	2016-2043	5.0 %	$ 2,625	$ 2,825	5.1	%	$ 2,825
First mortgage bonds	2016-2038	5.6	500	500	5.6		500
Gas facility revenue bonds	2022-2033	0.9	200	200	0.8		200
Medium-term notes	2017-2027	7.8	181	181	7.8		181
Total principal long-term debt		4.9 %	3,506	3,706	4.9	%	3,706
Fair value adjustment of long-term debt (3)	n/a	n/a	83	91	n/a		94
Unamortized debt premium, net	n/a	n/a	16	16	n/a		16
Total non-principal long-term debt		n/a	99	107	n/a		110
Total long-term debt			$ 3,605	$ 3,813			$ 3,816
Total debt			$ 4,486	$ 4,984			$ 4,648

(1) Interest rates are calculated based on the daily weighted average balance outstanding for the nine months ended September 30.

(2) As of September 30, 2014, the effective interest rates on our commercial paper borrowings were 0.3% for AGL Capital and 0.2% for Nicor Gas.

(3) See Note 4 for additional information on our fair value measurements.

Commercial Paper Programs

We maintain commercial paper programs at AGL Capital and Nicor Gas that consist of short-term, unsecured promissory notes used in conjunction with cash from operations to fund our seasonal working capital requirements. Working capital needs fluctuate during the year and are highest during the injection period in advance of the Heating Season. The Nicor Gas commercial paper program supports working capital needs at Nicor Gas, while all of our other subsidiaries and SouthStar participate in the AGL Capital commercial paper program. During the first nine months of

2014, our commercial paper maturities ranged from 1 to 108 days, and at September 30, 2014, remaining terms to maturity ranged from 1 to 24 days. Total borrowings and repayments netted to a payment of $490 million during the first nine months of 2014. For commercial paper issuances with original maturities over three months, borrowings and repayments were $50 million and $145 million, respectively, during the first nine months of 2014. During the three months ended September 30, 2014, we utilized a portion of the $225 million in proceeds from the sale of Tropical Shipping to reduce our commercial paper borrowings.

Financial and Non-Financial Covenants

The AGL Credit Facility and the Nicor Gas Credit Facility each include a financial covenant that requires us to maintain a ratio of total debt to total capitalization of no more than 70% at the end of any fiscal month. These ratios, as calculated in accordance with the debt covenants, include standby letters of credit and surety bonds and exclude accumulated OCI items related to non-cash pension adjustments, welfare benefits liability adjustments and accounting adjustments for cash flow hedges. Adjusting for these items, the following table contains our debt-to-capitalization ratios for the dates presented, which are below the maximum allowed.

	September 30, 2014		December 31, 2013		September 30, 2013	
AGL Credit Facility	53	%	57	%	56	%
Nicor Gas Credit Facility	57	%	55	%	50	%

The credit facilities contain certain non-financial covenants that, among other things, restrict liens and encumbrances, loans and investments, acquisitions, dividends and other restricted payments, asset dispositions, mergers and consolidations and other matters customarily restricted in such agreements.

Default Provisions

Our credit facilities and other financial obligations include provisions that, if not complied with, could require early payment or similar actions. The most important default events include the following:

- a maximum leverage ratio
- insolvency events and or nonpayment of scheduled principal or interest payments
- acceleration of other financial obligations
- change of control provisions

We have no triggering events in our debt instruments that are tied to changes in our specified credit ratings or our stock price, and have not entered into any transaction that requires us to issue equity based on credit ratings or other triggering events. We were in compliance with all existing debt provisions and covenants, both financial and non-financial, for all periods presented.

Note 8 - Equity

Our OCI amounts are aggregated within our accumulated other comprehensive loss. The following table provides changes in the components of our accumulated other comprehensive loss balance, net of the related income tax effects.

	2014			2013		
In millions (1)	Cash flow hedges	Retirement benefit plans	Total	Cash flow hedges	Retirement benefit plans	Total
For the three months ended September 30						
As of beginning of period	$ -	$ (133)	$ (133)	$ (1)	$ (208)	$ (209)
OCI, before reclassifications	(2)	-	(2)	-	-	-
Amounts reclassified from accumulated OCI	-	2	2	-	1	1
Net current-period other comprehensive (loss) income	(2)	2	-	-	1	1
As of end of period	$ (2)	$ (131)	$ (133)	$ (1)	$ (207)	$ (208)
For the nine months ended September 30						
As of beginning of period	$ 1	$ (137)	$ (136)	$ (3)	$ (215)	$ (218)
OCI, before reclassifications	2	-	2	-	-	-
Amounts reclassified from accumulated OCI	(5)	6	1	2	8	10
Net current-period other comprehensive (loss)	(3)	6	3	2	8	10

income						
As of end of period	$ (2)	$ (131)	$ (133)	$ (1)	$ (207)	$ (208)

(1) All amounts are net of income taxes. Amounts in parentheses indicate increases to our accumulated other comprehensive loss.

The following table provides details of the reclassifications out of accumulated other comprehensive loss and the impact on net income.

	Three months ended September 30,		Nine months ended September 30,	
In millions (1)	2014	2013	2014	2013
Cash flow hedges				
Cost of goods sold (natural gas contracts)	$(1)	$(1)	$4	$-
Operation and maintenance expense (natural gas contracts)	1	-	2	-
Interest expense (interest rate contracts)	-	1	-	(3)
Total before income tax	-	-	6	(3)
Income tax benefit	-	-	(1)	1
Total cash flow hedges	-	-	5	(2)
Retirement benefit plans				
Operation and maintenance expense (actuarial losses)(2)	(4)	(6)	(12)	(19)
Operation and maintenance expense (prior service credits) (2)	-	2	1	4
Total before income tax	(4)	(4)	(11)	(15)
Income tax benefit	2	3	5	7
Total retirement benefit plans	(2)	(1)	(6)	(8)
Total reclassification for the period	$(2)	$(1)	$(1)	$(10)

(1) Amounts in parentheses indicate reductions to our net income and accumulated other comprehensive loss. Except for retirement benefit plan amounts, the net income impacts are immediate.

(2) Amortization of these accumulated other comprehensive loss components is included in the computation of net periodic benefit cost. See Note 6 for additional details about net periodic benefit cost.

Note 9 - Non-Wholly Owned Entities

SouthStar, a joint venture owned by us and Piedmont, is our only significant VIE for which we are the primary beneficiary. This requires us to consolidate its assets, liabilities and statements of income. For additional information on SouthStar, see Note 10 to our Consolidated Financial Statements and related notes included in Item 8 of our 2013 Form 10-K/A. Earnings from SouthStar in 2014 and 2013 were allocated entirely in accordance with the ownership interests.

Cash flows used in our investing activities include capital expenditures for SouthStar of $6 million for the nine months ended September 30, 2014, and $2 million for the nine months ended September 30, 2013. Cash flows used in our financing activities include SouthStar's distribution to Piedmont for its portion of SouthStar's annual earnings from the previous year. Generally, this distribution occurs in the first quarter of each fiscal year. For each of the nine months ended September 30, 2014 and 2013, SouthStar distributed $17 million to Piedmont. SouthStar's creditors have no recourse to our general credit beyond our corporate guarantees that we have provided to SouthStar's counterparties and natural gas suppliers. The following table provides additional information about SouthStar's assets and liabilities as of the dates presented, which are consolidated within our unaudited Condensed Consolidated Statements of Financial Position.

	September 30, 2014 (1)			December 31, 2013 (1)			September 30, 2013 (1)		
In millions	Consolidated	SouthStar (2)	% (3)	Consolidated	SouthStar (2)	% (3)	Consolidated	SouthStar (2)	% (3)
Current assets	$ 2,093	$ 188	9 %	$ 2,895	$ 264	9 %	$ 2,252	$ 192	9 %
Goodwill and intangible assets	1,957	127	6	1,972	133	7	1,974	136	7
Long-term assets and other deferred debits	9,903	17	-	9,683	13	-	9,584	13	-
Total assets	$ 13,953	$ 332	2 %	$ 14,550	$ 410	3 %	$ 13,810	$ 341	2 %
Current liabilities	$ 2,462	$ 47	2 %	$ 3,118	$ 95	3 %	$ 2,407	$ 73	3 %
Long-term liabilities and other deferred credits	7,689	-	-	7,819	-	-	7,897	-	-
Total Liabilities	10,151	47	1	10,937	95	1	10,304	73	1
Equity	3,802	285	7	3,613	315	9	3,506	268	8
Total liabilities and equity	$ 13,953	$ 332	2 %	$ 14,550	$ 410	3 %	$ 13,810	$ 341	2 %

(1) Amounts revised and include prior period adjustments. See Note 13 for additional information.

(2) These amounts reflect information for SouthStar and exclude intercompany eliminations and the balances of our wholly owned subsidiary with an 85% ownership interest in SouthStar.

(3) SouthStar's percentage of the amount on our unaudited Condensed Consolidated Statements of Financial Position.

The following table provides information on SouthStar's operating revenues and operating expenses for the periods

presented, which are consolidated within our unaudited Condensed Consolidated Statements of Income.

In millions	Three months ended September 30, 2014	2013	Nine months ended September 30, 2014	2013
Operating revenues	$113	$98	$633	$464
Operating expenses				
Cost of goods sold	89	81	470	340
Operation and maintenance	19	16	62	49
Depreciation and amortization	3	2	8	3
Taxes other than income taxes	-	-	1	1
Total operating expenses	111	99	541	393
Operating income (loss)	$2	$(1)	$92	$71

Equity Method Investments

For more information about our equity method investments, see Note 10 to our Consolidated Financial Statements and related notes in Item 8 of our 2013 Form 10-K/A. The carrying amounts of our equity method investments within our unaudited Condensed Consolidated Statements of Financial Position were as follows:

In millions	September 30, 2014	December 31, 2013	September 30, 2013
Triton	$ 64	$70	$ 71
Horizon Pipeline	14	15	15
Other	2	1	9
Total	$ 80	$86	$ 95

Income from our equity method investments is classified as other income in our unaudited Condensed Consolidated Statements of Income. The following table provides the income from our equity method investments for the periods presented.

	Three months ended September 30,		Nine months ended September 30,	
In millions	2014	2013	2014	2013
Triton (1)	$2	$3	$5	$7
Other	-	-	1	1

(1) Reported within our "other" segment. For more information, see Note 11.

In the third quarter of 2014, we entered into two interstate pipeline joint ventures within our midstream operations segment as described below. The capacity from these joint ventures will further enhance system reliability as well as provide access to a more diverse supply of natural gas. We have concluded that, at present, both are VIEs. We are not considered the primary beneficiary and we have not consolidated the financial statements for these joint ventures in our unaudited Condensed Consolidated Financial Statements, because we share in the ability to direct the activities that most significantly impact their economic performance with their other member companies. We have accounted for our investment in these joint ventures using the equity method of accounting, and have classified the investment in other noncurrent assets in our unaudited Condensed Consolidated Statements of Financial Position.

PennEast Pipeline On August 11, 2014, we entered into a joint venture to develop and operate a 108-mile natural gas pipeline between New Jersey and Pennsylvania with initial transportation capacity of 800,000 dekatherms per day, which may be expanded to 1.2 Bcf per day. Our current investment in PennEast Pipeline is less than $1 million and represents a 20% ownership interest, and is the maximum extent of our current exposure to loss. Construction is expected to begin in the first quarter of 2017 with a targeted completion date in the fourth quarter of 2017.

Atlantic Coast Pipeline On September 2, 2014, we entered into a joint venture to develop and operate a 550-mile natural gas pipeline in North Carolina, Virginia, and West Virginia with initial transportation capacity of 1.5 Bcf per day, which may be expanded to 2.0 Bcf per day. Our current investment in Atlantic Coast Pipeline is less than $1 million and represents a 5% ownership interest, and is the maximum extent of our current exposure to loss. Construction is expected to begin in the second half of 2016 with a targeted completion date in the second half of 2018.

Note 10 - Commitments, Guarantees and Contingencies

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.

In 2014, we entered into several unconditional purchase obligations in the ordinary course of business. These include capacity and supply agreements related to the Dalton Pipeline, PennEast Pipeline, Atlantic Coast Pipeline and wholesale services, which are reflected in the table below. In addition, other contracts in the ordinary course of business have expired or ended. The following table illustrates our expected future contractual payments under our obligations and other commitments as of September 30, 2014.

2019 &

In millions	Total	2014	2015	2016	2017	2018	thereafter
Recorded contractual obligations:							
Long-term debt (1)	$3,706	$-	$200	$545	$22	$155	$2,784
Short-term debt	681	681	-	-	-	-	-
Environmental remediation liabilities (2)	454	16	83	104	50	38	163
Pipeline replacement program costs (2)	1	1	-	-	-	-	-
Total	$4,842	$698	$283	$649	$72	$193	$2,947
Unrecorded contractual obligations and commitments (3) (8):							
Pipeline charges, storage capacity and gas supply (4)	$3,837	$304	$564	$292	$185	$174	$2,318
Interest charges (5)	2,798	36	179	171	147	146	2,119
Operating leases (6)	207	11	35	31	24	18	88
Asset management agreements (7)	31	2	9	8	6	4	2
Standby letters of credit, performance/surety bonds (8)	27	9	17	1	-	-	-
Other	9	1	3	3	1	1	-
Total	$6,909	$363	$807	$506	$363	$343	$4,527

(1) Excludes the $77 million step up to fair value of first mortgage bonds, $16 million unamortized debt premium and $6 million interest rate swaps fair value adjustment. Includes current portion of long-term debt of $200 million, which matures in January 2015.

(2) Includes charges recoverable through base rates or rate rider mechanisms.

(3) In accordance with GAAP, these items are not reflected in our unaudited Condensed Consolidated Statements of Financial Position.

(4) Includes charges recoverable through a natural gas cost recovery mechanism or alternatively billed to Marketers and demand charges associated with Sequent. The gas supply balance includes amounts for Nicor Gas and SouthStar gas commodity purchase commitments of 66 Bcf at floating gas prices calculated using forward natural gas prices as of September 30, 2014, and is valued at $271 million. As we do for other subsidiaries, we provide guarantees to certain gas suppliers for SouthStar in support of payment obligations.

(5) Floating rate interest charges are calculated based on the interest rate as of September 30, 2014, and the maturity date of the underlying debt instrument. As of September 30, 2014, we have $42 million of accrued interest on our unaudited Condensed Consolidated Statements of Financial Position that will be paid in the next 12 months.

(6) We have certain operating leases with provisions for step rent or escalation payments and certain lease concessions. We account for these leases by recognizing the future minimum lease payments on a straight-line basis over the respective minimum lease terms, in accordance with GAAP. However, this lease accounting treatment does not affect the future annual operating lease cash obligations as shown herein. Our operating leases are primarily for real estate.

(7) Represent fixed-fee minimum payments for Sequent's affiliated asset management agreements.

(8) We provide guarantees to certain municipalities and other agencies and certain gas suppliers of SouthStar in support of payment obligations.

We also are involved in legal or administrative proceedings before various courts and agencies with respect to general claims, taxes, environmental, gas cost prudence reviews and other matters. Although we are unable to determine the ultimate outcomes of these other contingencies, we believe that our financial statements appropriately reflect these amounts, including the recording of liabilities when a loss is probable and reasonably estimable. For more information on these matters, see Note 11 in our Consolidated Financial Statements and related notes in Item 8 of our 2013 Form 10-K/A.

Contingencies and Guarantees

Contingent financial commitments, such as financial guarantees, represent obligations that become payable only if certain predefined events occur. We have certain subsidiaries that enter into various financial and performance guarantees and indemnities providing assurance to third parties. We believe the likelihood of payment under our guarantees is remote. No liability has been recorded for such guarantees and indemnifications as the fair value was inconsequential at inception.

Regulatory Matters

On December 21, 2012, Atlanta Gas Light filed a petition with the Georgia Commission for approval to resolve a volumetric imbalance of natural gas related to Atlanta Gas Light's use of retained storage assets to operationally balance the system for the benefit of the natural gas market. On September 11, 2014, we filed a stipulation that was entered between us, staff of the Georgia Commission and several marketers that include a resolution of the 4.6 Bcf imbalance over a five-year period from January 1, 2015 through December 31, 2019. Over the five-year period, discretionary funds available from the Universal Service Fund, which is controlled by the Georgia Commission, would be used to resolve 25% of the imbalance, or 1.15 Bcf of natural gas. Atlanta Gas Light would be obligated for 25% as well and we have recorded a reserve in our unaudited Condensed Consolidated Statements of Financial Position representing the future estimated cost to purchase the 1.15 Bcf of natural gas. Marketers would be obligated to resolve the remaining 50% of the imbalance, or 2.3 Bcf of natural gas. The Georgia Commission is expected to vote on the petition in December 2014. We are currently unable to predict the ultimate outcome.

On August 7, 2014, staff of the Illinois Commission and the Citizens Utility Board (CUB) filed testimony in the 2003 gas cost prudence review disputing certain gas loan transactions offered by Nicor Gas under its Chicago Hub services requesting refunds of $18 million and $22 million, respectively. We have filed testimony in this proceeding disputing that any refund is due. Similar gas loan transactions were provided in other open review years. The resolution will ultimately be decided by the Illinois Commission. We are currently unable to predict the ultimate outcome and have recorded no liability for this matter.

Environmental Matters

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control that require us to remove or remedy the effect on the environment of the disposal or release of specified substances at our current and former operating sites. See Note 3 for additional information.

Litigation

We are involved in litigation arising in the normal course of business. Although in some cases the company is unable to estimate the amount of loss reasonably possible in addition to any amounts already recognized, it is possible that the resolution of these contingencies, either individually or in aggregate, will require us to take charges against, or will result in reductions in, future earnings. Management believes that while the resolution of these contingencies, whether individually or in aggregate, could be material to earnings in a particular period, they will not have a material adverse

effect on our consolidated financial position or cash flows. For additional litigation information, see Note 11 in our Consolidated Financial Statements and related notes in Item 8 of our 2013 Form 10-K/A.

PBR Proceeding Nicor Gas' PBR plan was a regulatory plan that provided economic incentives based on natural gas cost performance. The PBR plan went into effect in 2000 and was terminated effective January 1, 2003, following allegations that Nicor Gas acted improperly in connection with the plan. Under this plan, Nicor Gas' total gas supply costs were compared to a market-sensitive benchmark. Savings and losses relative to the benchmark were determined annually and shared equally with sales customers. Since 2002, the amount of the savings and losses required to be shared has been disputed by the CUB and others, with the Illinois Attorney General (IAG) intervening, and subject to extensive contested discovery and other regulatory proceedings before administrative law judges and the Illinois Commission. In 2009, the staff of the Illinois Commission, IAG and CUB requested refunds of $85 million, $255 million and $305 million, respectively.

In February 2012, we committed to a stipulation with the staff of the Illinois Commission for a resolution of the dispute through credits to Nicor Gas customers of $64 million. On November 5, 2012, the Administrative Law Judges issued a proposed order for a refund of $72 million to ratepayers. In the fourth quarter of 2012, we increased our accrual for this dispute by $8 million for a total of $72 million as a result of these developments and their effect on the estimated liability.

On June 7, 2013, the Illinois Commission issued an order requiring us to refund $72 million to current Nicor Gas customers through our purchased gas adjustment mechanism based upon natural gas throughput over 12 months beginning on July 1, 2013. Approximately $43 million was refunded during the first half of 2014, which resulted in the completion of all refunds. On February 28, 2014, the CUB appealed the Illinois Commission's order requesting refunds consistent with its 2009 request to the appellate court in Illinois and Nicor Gas filed its response brief on July 25, 2014. The CUB filed its reply brief on October 17, 2014. There is no set time frame for a final ruling by the appellate court.

Note 11 - Segment Information

Our operating segments comprise revenue-generating components of our company for which we produce separate financial information internally that regularly is used to make operating decisions and assess performance. Our determination of reportable segments considers the strategic operating units under which we manage sales of various products and services to customers in differing regulatory environments. We manage our businesses through four operating segments - distribution operations, retail operations, wholesale services and midstream operations - and other, a non-operating segment.

Effective September 1, 2014, we closed on the sale of Tropical Shipping, which historically operated within our cargo shipping segment. The assets and liabilities of these businesses are classified as held for sale on the unaudited Condensed Consolidated Statements of Financial Position, and the financial results of these businesses are reflected as discontinued operations on the unaudited Condensed Consolidated Statements of Income. Amounts shown in this note, unless otherwise indicated, exclude assets held for sale and discontinued operations. Cargo shipping also included our investment in Triton, which was not part of the sale and has been reclassified into our "other" segment. See Note 12 for additional information.

Our distribution operations segment is the largest component of our business and includes natural gas local distribution utilities in seven states. These utilities construct, manage and maintain intrastate natural gas pipelines and distribution facilities. Although the operations of our distribution operations segment are geographically dispersed, the operating subsidiaries within the distribution operations segment are all regulated utilities, with rates determined by individual state regulatory commissions. These natural gas distribution utilities have similar economic and risk characteristics.

We are also involved in several related and complementary businesses. Our retail operations segment includes retail natural gas marketing to end-use customers primarily in Georgia and Illinois. Additionally, retail operations provide home protection products and services. Our wholesale services segment engages in natural gas storage and gas pipeline arbitrage and related activities. Additionally, they provide natural gas asset management and/or related logistics services for each of our utilities except Nicor Gas, as well as for nonaffiliated companies. Our midstream operations segment includes our non-utility storage and pipeline operations, including the operation of high-deliverability natural gas storage assets. Our "other" segment includes aggregated subsidiaries that individually are not significant on a stand-alone basis and that do not fit into one of our operating segments.

24

The chief operating decision maker of the company is the Chairman, President and Chief Executive Officer, who utilizes EBIT as the primary measure of profit and loss in assessing the results of each segment's operations. EBIT includes operating income and other income and expenses. Items we do not include in EBIT are income taxes and financing costs, including interest expense, each of which we evaluate on a consolidated basis. Summarized Statements of Income, Statements of Financial Position and capital expenditure information by segment as of and for the periods presented are shown in the following tables.

Three months ended September 30, 2014

In millions	Distribution operations	Retail operations	Wholesale services (1)	Midstream operations	Other (3)	Intercompany eliminations	Consolidated
Operating revenues from external parties	$ 439	$ 146	$ 5	$ 4	$ 1	$ (6)	$ 589
Intercompany revenues	35	-	-	-	-	(35)	-
Total operating revenues	474	146	5	4	1	(41)	589
Operating expenses							
Cost of goods sold	138	99	3	(3)	-	(39)	198
Operation and maintenance	145	34	10	5	1	(2)	193
Depreciation and amortization	79	7	-	5	2	-	93
Taxes other than income taxes	24	1	1	1	3	-	30
Total operating expenses	386	141	14	8	6	(41)	514
Gain on disposition of assets	-	-	3	-	-	-	3
Operating income (loss)	88	5	(6)	(4)	(5)	-	78
Other income (expense)	1	-	(1)	-	3	-	3
EBIT	$ 89	$ 5	$ (7)	$ (4)	$ (2)	$ -	$ 81
Capital expenditures	$ 196	$ 3	$ -	$ 3	$ 9	$ -	$ 211

Three months ended September 30, 2013

In millions	Distribution operations (4)	Retail operations (4)	Wholesale services (1)	Midstream operations	Other (3)	Intercompany eliminations	Consolidated (4)
Operating revenues from external parties	$ 409	$ 138	$ 13	$ 19	$ 1	$ (6)	$ 574
Intercompany revenues	36	-	-	-	-	(36)	-
Total operating revenues	445	138	13	19	1	(42)	574

Operating expenses							
Cost of goods sold	111	92	1	9	-	(39)	174
Operation and maintenance	150	31	13	5	3	(3)	199
Depreciation and amortization	89	8	-	5	2	-	104
Taxes other than income taxes	22	1	1	1	2	-	27
Total operating expenses	372	132	15	20	7	(42)	504
Operating income (loss)	73	6	(2)	(1)	(6)	-	70
Other income	4	-	-	-	3	-	7
EBIT	$ 77	$ 6	$ (2)	$ (1)	$ (3)	$ -	$ 77
Capital expenditures	$ 200	$ 3	$ -	$ 3	$ 5	$ -	$ 211

Nine months ended September 30, 2014

In millions	Distribution operations (4)	Retail operations (4)	Wholesale services (1)	Midstream operations	Other (3)	Intercompany eliminations	Consolidated (4)
Operating revenues from external parties	$ 2,821	$ 728	$ 383	$ 65	$ 5	$ (62)	$ 3,940
Intercompany revenues	153	1	-	-	-	(154)	-
Total operating revenues	2,974	729	383	65	5	(216)	3,940
Operating expenses							
Cost of goods sold	1,655	498	13	44	-	(210)	2,000
Operation and maintenance	515	105	59	18	2	(6)	693
Depreciation and amortization	235	21	1	14	10	-	281
Taxes other than income taxes	146	3	2	4	5	-	160
Total operating expenses	2,551	627	75	80	17	(216)	3,134
Gain on disposition of assets	-	-	3	-	-	-	3
Operating income (loss)	423	102	311	(15)	(12)	-	809
Other income (expense)	5	-	(3)	1	5	-	8
EBIT	$ 428	$ 102	$ 308	$ (14)	$ (7)	$ -	$ 817
Identifiable and total assets (2)	$ 11,628	$ 663	$ 1,056	$ 692	$ 9,167	$ (9,253)	$ 13,953
Capital expenditures	$ 504	$ 9	$ 1	$ 8	$ 21	$ -	$ 543

Nine months ended September 30, 2013

In millions	Distribution operations (4)	Retail operations (4)	Wholesale services (1)	Midstream operations	Other (3)	Intercompany eliminations	Consolidated (4)
Operating revenues from external parties	$ 2,266	$ 605	$ 73	$ 58	$ 5	$ (16)	$ 2,991
Intercompany revenues	134	-	-	-	-	(134)	-
Total operating revenues	2,400	605	73	58	5	(150)	2,991
Operating expenses							
Cost of goods sold	1,142	402	21	25	-	(143)	1,447
Operation and maintenance	493	94	36	17	1	(7)	634
Depreciation and amortization	265	20	1	13	10	-	309
Taxes other than income taxes	124	3	2	4	6	-	139
Total operating expenses	2,024	519	60	59	17	(150)	2,529
Gain on disposition of assets	-	-	11	-	-	-	11
Operating income (loss)	376	86	24	(1)	(12)	-	473
Other income	11	-	-	2	5	-	18
EBIT	$ 387	$ 86	$ 24	$ 1	$ (7)	$ -	$ 491
Identifiable and total assets (2)	$ 11,215	$ 644	$ 930	$ 726	$ 9,784	$ (9,783)	$ 13,516
Capital expenditures	$ 495	$ 7	$ -	$ 11	$ 13	$ -	$ 526

(1) The revenues for wholesale services are netted with costs associated with its energy and risk management activities. A reconciliation of our operating revenues and our intercompany revenues is shown in the following table.

In millions	Third party gross revenues (4)	Intercompany revenues	Total gross revenues (4)	Less gross gas costs	Operating revenues (4)
Three months ended September 30, 2014	$1,885	$ 126	$2,011	$2,006	$5
Three months ended September 30, 2013	1,716	69	1,785	1,772	13
Nine months ended September 30, 2014	8,313	584	8,897	8,514	383
Nine months ended September 30, 2013	5,792	312	6,104	6,031	73

(2) Identifiable assets are those used in each segment's operations and exclude assets held for sale.

(3) Our other segment now also includes our investment in Triton, which was part of our cargo shipping segment that has been classified as discontinued operations. For more information, see Note 12.

(4) Amounts revised and include prior period adjustments. See Note 13 for additional information.

Information by segment on our Statements of Financial Position as of December 31, 2013, is as follows:

In millions		Identifiable and total assets
Distribution operations (1)	$	11,634
Retail operations (1)		685
Wholesale services (1)		1,163
Midstream operations		713
Other		10,160
Intercompany elimination		(10,088)
Consolidated (1)	$	14,267

(1) Amounts revised for prior period adjustments. See Note 13 for additional information.

Note 12 - Discontinued Operations

On September 1, 2014, we closed on the sale of Tropical Shipping to an unrelated third party. The after-tax cash proceeds and distributions from the transaction were $225 million. We determined that the cumulative foreign earnings of Tropical Shipping would no longer be indefinitely reinvested offshore. Accordingly, we recognized income tax expense of $60 million, of which $31 million was recorded in the first quarter of 2014, and the remaining $29 million was recorded in the third quarter of 2014 related to the cumulative foreign earnings for which no tax liabilities had been previously recorded, resulting in our repatriation of $86 million in cash.

During the first quarter of 2014, based upon the negotiated sales price, we also recorded a goodwill impairment charge of $19 million, for which there is no income tax benefit. Additionally, we recognized a total of $7 million charge in the second and third quarters of 2014 related to the suspension of depreciation and amortization for assets that we were not compensated for by the buyer. The assets and liabilities of Tropical Shipping classified as held for sale on the unaudited Condensed Consolidated Statements of Financial Position are as follows:

In millions	December 31, 2013	September 30, 2013
Current assets		
Cash and cash equivalents	$24	$34
Short-term investments	1	1
Receivables	36	33
Inventories	9	9
Other	1	3
Total current assets	71	80
Long-term assets and other deferred debits		
Property, plant and equipment, net	124	126
Goodwill	61	61
Intangible assets	19	19
Other	8	8
Total long-term assets and other deferred debits	212	214
Total assets held for sale	$283	$294
Current liabilities		
Other accounts payable - trade	$11	$9
Accrued expenses	7	7
Other	22	23
Total liabilities held for sale	$40	$39

The financial results of these businesses are reflected as discontinued operations, and all prior periods presented have been recast to reflect the discontinued operations. The components of discontinued operations recorded on the unaudited Condensed Consolidated Statements of Income are as follows:

	Three months ended September 30,		Nine months ended September 30,	
In millions	2014	2013	2014	2013
Operating revenues	$62	$89	$243	$264
Operating expenses				
Cost of goods sold	38	55	149	162
Operation and maintenance (1)	20	27	75	82

Depreciation and amortization (2)	-	4	5	14
Taxes other than income taxes	1	2	5	5
Loss on sale and goodwill impairment (3)	5	-	28	-
Total operating expenses	64	88	262	263
Operating (loss) income	(2)	1	(19)	1
(Loss) income before income taxes	(2)	1	(19)	1
Income tax expense (4)	(29)	-	(61)	-
(Loss) Income from discontinued operations, net of tax	$(31)	$1	$(80)	$1

(1) Includes $1 million for the three and nine months ended September 30, 2014, for another business not related to Tropical Shipping that we discontinued in the third quarter of 2014 and was included in our “other” segment.

(2) We ceased depreciating and amortizing Tropical Shipping’s assets on April 4, 2014, as a result of entering into an agreement to sell this business and the assets were classified as held for sale.

(3) Primarily relates to the suspension of depreciation and amortization for the nine months ended September 30, 2014 of $7 million and $19 million of goodwill attributable to Tropical Shipping that was impaired as of March 31, 2014, based on the negotiated sales price.

(4) Includes $31 million and $29 million that were recorded in the first and third quarters of 2014, respectively, related to the cumulative foreign earnings for which no tax liabilities had been previously recorded.

Note 13 - Revision to Prior Period Financial Statements

In September 2014, we identified an accounting issue in our revenue recognition related to certain of our regulatory infrastructure programs. Historically, our regulatory accounting models used to record revenues under these programs did not differentiate between allowable costs based on what the regulator had approved compared to costs that meet the definition of an incurred cost that would otherwise be charged to expense under the accounting literature. Specifically, Accounting Standards Codification (ASC) 980 - Regulated Operations prohibits capitalizing allowed, but not incurred, costs such as shareholder return, even if allowed by a respective state regulatory body. Shareholder returns and other allowed, but not incurred, costs can generally only be recognized in earnings when they are collected through rates. This change is only applicable to our distribution operations segment and primarily affects our operating revenues, operation and maintenance expense, depreciation and amortization, interest expense and income tax expense amounts.

Additionally, we have determined that our use of the straight-line method of amortizing our intangible assets was not applied consistent with the requirements of ASC 350 Intangibles-Goodwill and Other (ASC 350). ASC 350 requires that an intangible asset be amortized over its useful life in a manner to reflect the pattern in which the economic benefits of the intangible assets are consumed. We have determined that we should be utilizing the undiscounted cash flows as a basis to amortize these assets. Other previously identified immaterial uncorrected amounts are reflected in the revised amounts.

We assessed the materiality of these issues on our prior period financial statements and concluded they were not material to any prior annual or interim periods; however, the cumulative impact would have been material to the interim period ended September 30, 2014, if adjusted in 2014. As a result, in accordance with accounting standards, we revised our prior period financial statements as described below to correct for these adjustments. The revision had no effect on reported cash flows and would not have changed incentive compensation for any periods. The following tables present the effects of the revisions to our unaudited Condensed Consolidated Statements of Income, unaudited Condensed Consolidated Statements of Financial Position and unaudited Condensed Consolidated Statements of Cash Flows for the following interim periods:

	For the three months ended March 31, 2014			For the three months ended June 30, 2014			For the six months ended June 30, 2014		
In millions, except per share amounts	As filed (1)	Adjustment	Revised	As filed (2)	Adjustment	Revised	As filed (2)	Adjustment	Revised
Operating revenues	$ 2,474	$ (12)	$ 2,462	$ 902	$ (13)	$ 889	$ 3,376	$ (25)	$ 3,351
Operating expenses									
Cost of goods sold	1,400	-	1,400	402	-	402	1,802	-	1,802
Operation and maintenance	289	-	289	211	-	211	500	-	500
Depreciation and amortization	93	-	93	95	-	95	188	-	188
Taxes other than income taxes	88	-	88	42	-	42	130	-	130
Total operating expenses	1,870	-	1,870	750	-	750	2,620	-	2,620
	604	(12)	592	152	(13)	139	756	(25)	731

Operating income									
Other income	3	-	3	2	-	2	5	-	5
Interest expense, net	(48)	2	(46)	(48)	3	(45)	(96)	5	(91)
Income before income taxes	559	(10)	549	106	(10)	96	665	(20)	645
Income tax expense	207	(4)	203	41	(4)	37	248	(8)	240
Income from continuing operations	352	(6)	346	65	(6)	59	417	(12)	405
Income (loss) from discontinued operations	(50)	-	(50)	1	-	1	(49)	-	(49)
Net income	302	(6)	296	66	(6)	60	368	(12)	356
Less net income attributable to the noncontrolling interest	12	-	12	2	-	2	14	-	14
Net income attributable to AGL Resources Inc.	$ 290	$ (6)	$ 284	$ 64	$ (6)	$ 58	$ 354	$ (12)	$ 342
Per common share information									
Basic earnings (loss) per common share (3)									
Continuing operations	$ 2.87	$ (0.05)	$ 2.82	$ 0.53	$ (0.05)	$ 0.48	$ 3.40	$ (0.10)	$ 3.30
Discontinued operations	(0.43)	-	(0.43)	0.01	-	0.01	(0.42)	-	(0.42)
Basic earnings per common share attributable to AGL Resources Inc. common shareholders	$ 2.44	$ (0.05)	$ 2.39	$ 0.54	$ (0.05)	$ 0.49	$ 2.98	$ (0.10)	$ 2.88
Diluted earnings (loss) per common share (3)									
Continuing operations	$ 2.86	$ (0.05)	$ 2.81	$ 0.53	$ (0.05)	$ 0.48	$ 3.39	$ (0.10)	$ 3.29
Discontinued operations	(0.43)	-	(0.43)	0.01	-	0.01	(0.42)	-	(0.42)
	$ 2.43	$ (0.05)	$ 2.38	$ 0.54	$ (0.05)	$ 0.49	$ 2.97	$ (0.10)	$ 2.87

Diluted earnings per common share attributable to AGL Resources Inc. common shareholders

(1) Reflects the reclassification of the Tropical Shipping amounts as discontinued operations.

(2) Reflects the reclassification of the Tropical Shipping amounts as discontinued operations, as filed in our second quarter 2014 Form 10-Q.

(3) Excludes net income attributable to the noncontrolling interest.

	For the three months ended								
	March 31, 2013			June 30, 2013			September 30, 2013		
In millions, except per share amounts	As filed (1)	Adjustment	Revised	As filed (2)	Adjustment	Revised	As filed (1)	Adjustment	Revised
Operating revenues	$ 1,622	$ (10)	$ 1,612	$ 816	$ (11)	$ 805	$ 586	$ (12)	$ 574
Operating expenses									
Cost of goods sold	920	-	920	353	-	353	174	-	174
Operation and maintenance	232	(1)	231	205	(1)	204	199	-	199
Depreciation and amortization	102	-	102	103	-	103	105	(1)	104
Taxes other than income taxes	70	(1)	69	43	-	43	27	-	27
Total operating expenses	1,324	(2)	1,322	704	(1)	703	505	(1)	504
Gain on disposition of assets	-	-	-	11	-	11	-	-	-
Operating income	298	(8)	290	123	(10)	113	81	(11)	70
Other income	5	-	5	7	(1)	6	7	-	7
Interest expense, net	(46)	1	(45)	(46)	2	(44)	(43)	6	(37)
Income before income taxes	257	(7)	250	84	(9)	75	45	(5)	40
Income tax expense	94	(3)	91	33	(3)	30	18	(2)	16
Income from continuing operations	163	(4)	159	51	(6)	45	27	(3)	24
Income (loss) from discontinued operations	1	-	1	(1)	-	(1)	1	-	1
Net income	164	(4)	160	50	(6)	44	28	(3)	25
Less net income attributable to the noncontrolling interest	10	-	10	1	-	1	-	-	-
Net income attributable to AGL Resources Inc.	$ 154	$ (4)	$ 150	$ 49	$ (6)	$ 43	$ 28	$ (3)	$ 25

Per common share information									
Basic earnings per common share (3)									
Continuing operations	$ 1.30	$ (0.03)	$ 1.27	$ 0.42	$ (0.04)	$ 0.38	$ 0.23	$ (0.03)	$ 0.20
Discontinued operations	0.01	-	0.01	(0.01)	-	(0.01)	0.01	-	0.01
Basic earnings per common share attributable to AGL Resources Inc. common shareholders	$ 1.31	$ (0.03)	$ 1.28	$ 0.41	$ (0.04)	$ 0.37	$ 0.24	$ (0.03)	$ 0.21
Diluted earnings (loss) per common share (3)									
Continuing operations	$ 1.30	$ (0.04)	$ 1.26	$ 0.42	$ (0.04)	$ 0.38	$ 0.23	$ (0.03)	$ 0.20
Discontinued operations	0.01	-	0.01	(0.01)	-	(0.01)	0.01	-	0.01
Diluted earnings per common share attributable to AGL Resources Inc. common shareholders	$ 1.31	$ (0.04)	$ 1.27	$ 0.41	$ (0.04)	$ 0.37	$ 0.24	$ (0.03)	$ 0.21

(1) Reflects the reclassification of the Tropical Shipping amounts as discontinued operations.

(2) Reflects the reclassification of the Tropical Shipping amounts as discontinued operations, as filed in our second quarter 2014 Form 10-Q.

(3) Excludes net income attributable to the noncontrolling interest.

In millions, except per share amounts	For the six months ended June 30, 2013			For the nine months ended September 30, 2013		
	As filed (1)	Adjustment	Revised	As filed (2)	Adjustment	Revised
Operating revenues	$ 2,438	$ (21)	$ 2,417	$ 3,024	$ (33)	$ 2,991
Operating expenses						
Cost of goods sold	1,273	-	1,273	1,447	-	1,447
Operation and maintenance	437	(2)	435	636	(2)	634
Depreciation and amortization	206	(1)	205	311	(2)	309
Taxes other than income taxes	112	-	112	139	-	139
Total operating expenses	2,028	(3)	2,025	2,533	(4)	2,529
Gain on disposition of assets	11	-	11	11	-	11
Operating income	421	(18)	403	502	(29)	473
Other income	12	(1)	11	19	(1)	18
Interest expense, net	(92)	3	(89)	(135)	9	(126)
Income before income taxes	341	(16)	325	386	(21)	365
Income tax expense	127	(6)	121	145	(8)	137
Income from continuing operations	214	(10)	204	241	(13)	228
Income from discontinued operations, net of tax	-	-	-	1	-	1
Net income	214	(10)	204	242	(13)	229
Less net income attributable to the noncontrolling interest	11	-	11	11	-	11
Net income attributable to AGL Resources Inc.	$ 203	$ (10)	$ 193	$ 231	$ (13)	$ 218
Per common share information						
Basic earnings per common share (3)						
Continuing operations	$ 1.72	$ (0.07)	$ 1.65	$ 1.95	$ (0.10)	$ 1.85
Discontinued operations	-	-	-	0.01	-	0.01
Basic earnings per common share attributable to AGL Resources Inc. common shareholders	$ 1.72	$ (0.07)	$ 1.65	$ 1.96	$ (0.10)	$ 1.86
Diluted earnings (loss) per common share (3)						

Continuing operations	$ 1.72	$ (0.08)	$ 1.64	$ 1.95	$ (0.11)	$ 1.84
Discontinued operations	-	-	-	0.01	-	0.01
Diluted earnings per common share attributable to AGL Resources Inc. common shareholders	$ 1.72	$ (0.08)	$ 1.64	$ 1.96	$ (0.11)	$ 1.85

(1) Reflects the reclassification of the Tropical Shipping amounts as discontinued operations, as filed in our second quarter 2014 Form 10-Q, which had no effect on net income or basic and diluted earnings per common share for the six months ended June 30, 2013.

(2) Reflects the reclassification of the Tropical Shipping amounts as discontinued operations.

(3) Excludes net income attributable to the noncontrolling interest.

	As of March 31, 2014		As of June 30, 2014	
In millions	As filed	Revised	As filed (1)	Revised
Current assets				
Regulatory assets	$297	$250	$211	$165
Other	127	126	122	121
Total current assets	3,637	3,589	2,431	2,384
Long-term assets and other deferred debits				
Property, plant and equipment	11,068	11,054	11,202	11,188
Less accumulated depreciation	2,368	2,367	2,401	2,400
Property, plant and equipment, net	8,700	8,687	8,801	8,788
Regulatory assets	736	696	775	726
Intangible assets	151	140	147	135
Total long-term assets and other deferred debits	11,739	11,675	11,871	11,797
Total assets	$15,376	$15,264	$14,302	$14,181
Long-term liabilities and other deferred credits				
Accumulated deferred income taxes	$1,699	$1,655	$1,721	$1,675
Total long-term liabilities and other deferred credits	7,711	7,667	7,772	7,726
Total liabilities and other deferred credits	$11,465	$11,421	$10,368	$10,321
Equity				
Additional paid-in capital	$2,059	$2,060	$2,072	$2,073
Retained earnings	1,358	1,289	1,363	1,288
Total equity	3,911	3,843	3,934	3,860
Total liabilities and equity	$15,376	$15,264	$14,302	$14,181

(1) Reflects the reclassification of the Tropical Shipping amounts as held for sale, as filed in our second quarter 2014 Form 10-Q

In millions	As of March 31, 2013		As of June 30, 2013		As of September 30, 2013	
	As filed	Revised	As filed (1)	Revised	As filed	Revised
Current assets						
Regulatory assets	$119	$72	$120	$74	$133	$87
Total current assets	2,577	2,530	2,277	2,231	2,091	2,252
Long-term assets and other deferred debits						
Property, plant and equipment	10,463	10,450	10,613	10,599	10,920	10,761
Less accumulated depreciation	2,181	2,181	2,240	2,240	2,307	2,281
Property, plant and equipment, net	8,282	8,269	8,373	8,359	8,613	8,480
Regulatory assets	878	868	898	880	871	845
Intangible assets	136	131	164	158	180	152
Other	245	231	244	241	251	259
Total long-term assets and other deferred debits	11,363	11,332	11,518	11,477	11,813	11,558
Total assets	$13,940	$13,862	$13,795	$13,708	$13,904	$13,810
Current liabilities						
Accrued expenses	$162	$161	$164	$163	$157	$149
Total current liabilities	3,060	3,059	2,349	2,348	2,407	2,407
Long-term liabilities and other deferred credits						
Accumulated deferred income taxes	1,568	1,539	1,567	1,534	1,587	1,551
Total long-term liabilities and other deferred credits	7,339	7,310	7,891	7,858	7,934	7,897
Total liabilities and other deferred credits	$10,399	$10,369	$10,240	$10,206	$10,341	$10,304
Equity						
Additional paid-in capital	$2,019	$2,020	$2,035	$2,037	$2,046	$2,047
Retained earnings	1,134	1,085	1,127	1,072	1,100	1,042
Total equity	3,541	3,493	3,555	3,502	3,563	3,506
Total liabilities and equity	$13,940	$13,862	$13,795	$13,708	$13,904	$13,810

(1) Reflects the reclassification of the Tropical Shipping amounts as held for sale, as filed in our second quarter 2014 Form 10-Q

In millions	For the three months ended March 31, 2014			For the six months ended June 30, 2014		
	As filed	Adjustment	Revised	As filed	Adjustment	Revised
Cash flows from operating activities						
Net income	$302	$(6)	$296	$368	$(12)	$356
Adjustments to reconcile net income to net cash flow provided by operating activities						

Depreciation and amortization	93	-	93
Deferred income taxes	42	(34)	8
Changes to certain assets and liabilities			
Other, net	57	40	97
Net cash flow provided by operating activities	$853	-	$853

	For the three months ended March 31, 2013			For the six months ended June 30, 2013			For the nine months ended September 30, 2013		
In millions	As filed	Adjustment	Revised	As filed	Adjustment	As filed	As filed	Adjustment	Revised
Cash flows from operating activities									
Net income	$ 164	$ (4)	$ 160	$ 214	$ (10)	$ 204	$ 242	$ (13)	$ 229
Adjustments to reconcile net income to net cash flow provided by operating activities									
Depreciation and amortization	102	-	102	206	(1)	205	311	(2)	309
Deferred income taxes	(24)	(1)	(25)	(14)	(6)	(20)	(28)	(4)	(32)
Changes to certain assets and liabilities									
Other, net	32	5	37	14	17	31	63	19	82
Net cash flow provided by operating activities	$ 850	-	$ 850	$ 1,161	-	$ 1,161	$ 1,070	-	$ 1,070

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

The following discussion and analysis should be read in conjunction with our unaudited Condensed Consolidated Financial Statements and the related notes in this quarterly filing, as well as our 2013 Form 10-K/A. Results for the interim periods presented are not necessarily indicative of the results to be expected for the full fiscal period due to seasonal and other factors.

Forward-Looking Statements

Certain expectations and projections regarding our future performance referenced in this 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 and are subject to uncertainties and risks. 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 often include words such as "anticipate," "assume," “believe,” "can," "could," "estimate," "expect," "forecast," "future," “goal,” "indicate," "intend," "may," “outlook,” "plan," “potential,” "predict," "project," “proposed,” "seek," "should," "target," "would," or similar expressions. You are cautioned not to place undue reliance on our forward-looking statements. While we believe that our expectations are reasonable in view of the available information that we currently have, our expectations are subject to future events, risks and uncertainties, and there are numerous factors - many beyond our control - that could cause our actual results to differ materially 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 and our ability to recover our project costs from our customers; limits on pipeline capacity; the impact of acquisitions and divestitures; our ability to successfully integrate operations that we have or may acquire or develop in the future; direct or indirect effects on our business, financial condition or liquidity resulting from any change in our credit ratings, or any change in the credit ratings of our counterparties or competitors; interest rate fluctuations; financial market conditions, including disruptions in the capital markets and lending environment; general economic conditions; uncertainties about environmental issues and the related impact of such issues, including our environmental remediation plans; the capacity of our gas storage caverns, which are subject to natural settling and other occurrences; the impact of our construction projects and related capital expenditures, including our pipeline projects; the development, timing and anticipated costs relating to our pipeline projects; 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; the outcome of litigation; and other factors discussed elsewhere herein and in our other filings with the SEC. There also may be other factors that we do not anticipate or that we do not recognize as material that are not described in this report that could cause our actual results to differ materially from our expectations.

Forward-looking statements speak only as of the date they are made. We expressly disclaim any obligation to publicly update or revise any forward-looking statement, whether as a result of future events, new information or otherwise, except as required by law.

Executive Summary

We are an energy services holding company whose principal business is the distribution of natural gas in seven states - Illinois, Georgia, Virginia, New Jersey, Florida, Tennessee and Maryland - through our seven natural gas distribution utilities. We are also involved in several other businesses that are primarily related and complementary to the distribution of natural gas. Our operating segments consist of four operating and reporting segments - distribution operations, retail operations, wholesale services and midstream operations and one non-operating segment - other. These segments are consistent with how management views and operates our business. For additional information on our operating segments, see Note 11 to our unaudited Condensed Consolidated Financial Statements herein and Item 1, “Business” of our 2013 Form 10-K.

In the third quarter of 2014, we revised the accounting treatment for our previously-reported non-cash revenue recognition associated with our infrastructure replacement programs. The adjustments did not affect previously-reported operating cash flows, nor are they expected to affect capital expenditure plans or dividend payments. The infrastructure replacement programs are expected to generate the same levels of return as previously communicated, as all amounts will be recovered in accordance with allowed recovery mechanisms. The adjustments related only to the timing of recognition and do not impact rates charged to customers. These adjustments impacted our distribution operations segment. Additionally, we corrected the amortization of customer relationship and trade name intangibles in our retail operations segment to reflect the amortization expense on a declining basis consistent with the pattern of undiscounted cash flows used to determine their fair values. See Note 13 to our unaudited Condensed Consolidated Financial Statements herein for additional information on these adjustments. As indicated in the tables below, these adjustments resulted in the following impact to our previously reported financial results.

Distribution operations

In millions	Operating margin (1)(2)	Operating expenses (2)	EBIT (1)	Operating margin (1) (2)	Operating expenses (2)	EBIT (1)
Three months ended		March 31, 2014			March 31, 2013	
As filed	$ 544	$ 306	$ 239	$ 505	$ 290	$ 218
Adjustment	(12)	(2)	(10)	(9)	(2)	(7)
Revised	$ 532	$ 304	$ 229	$ 496	$ 288	$ 211
Three months ended		June 30, 2014			June 30, 2013	
As filed	$ 371	$ 254	$ 120	$ 368	$ 263	$ 109
Adjustment	(12)	(2)	(10)	(13)	(3)	(10)
Revised	$ 359	$ 252	$ 110	$ 355	$ 260	$ 99
Six months ended		June 30, 2014			June 30, 2013	
As filed	$ 915	$ 560	$ 359	$ 873	$ 553	$ 327
Adjustment	(24)	(4)	(20)	(22)	(5)	(17)
Revised	$ 891	$ 556	$ 339	$ 851	$ 548	$ 310

Retail operations

Three months ended		March 31, 2014			March 31, 2013	
As filed	$ 126	$ 44	$ 82	$ 107	$ 37	$ 70
Adjustment	-	2	(2)	-	1	(1)
Revised	$ 126	$ 46	$ 80	$ 107	$ 38	$ 69
Three months ended		June 30, 2014			June 30, 2013	
As filed	$ 58	$ 40	$ 18	$ 50	$ 38	$ 12
Adjustment	-	1	(1)	-	1	(1)
Revised	$ 58	$ 41	$ 17	$ 50	$ 39	$ 11
Six months ended		June 30, 2014			June 30, 2013	
As filed	$ 184	$ 84	$ 100	$ 157	$ 75	$ 82
Adjustment	-	3	(3)	-	2	(2)

Revised	$ 184	$ 87	$ 97	$ 157	$ 77	$ 80

(1) Operating margin is a non-GAAP measure. A reconciliation of operating revenue and operating margin to operating income, and EBIT to income before income taxes and net income is contained in "Results of Operations" herein. See Note 11 to our unaudited Condensed Consolidated Financial Statements under Part I, Item 1 herein for additional segment information.

(2) Operating margin and operating expenses are adjusted for revenue tax expenses, which are passed directly through to our customers.

In September 2014, we closed on the sale of Tropical Shipping and received after-tax cash proceeds of $225 million and we repatriated $86 million in cash. The transaction resulted in expenses of approximately $(0.67) per share for the nine months ended September 30, 2014, of which $(0.42) was recorded in the first quarter of 2014 with the remaining $(0.25) recorded in the third quarter of 2014. Tropical Shipping operated as part of our cargo shipping segment and the financial results are classified as discontinued operations. The cargo shipping segment also included our investment in Triton, which has been reclassified into our "other" segment. Accordingly, all references to continuing operations exclude the operations of Tropical Shipping. The sale of Tropical Shipping will allow us to focus on growing our core business of operating regulated utilities and complementary non-regulated energy businesses and provide us with flexibility around our long-term financing plans. For additional information on our discontinued operations, see Note 12 to our unaudited Condensed Consolidated Financial Statements herein.

For the third quarter of 2014, net loss attributable to AGL Resources Inc. was $8 million, which includes a $31 million after-tax loss from discontinued operations. For the third quarter of 2014, our net income from continuing operations was $23 million, a decrease of $1 million compared to net income from continuing operations for the same period in 2013. The decrease was primarily the result of the following:

- Decreased EBIT at our midstream operations segment mainly due to lower contracted firm rates at Jefferson Island and Central Valley storage facilities.
- Decreased operating margin at wholesale services due to lower commercial activity related to the tightening of transportation spreads compared to the same period last year, and additional LOCOM adjustments.
- The decreases were partially offset by an increase in operating margin at distribution operations as a result of increased average customer usage and customer growth, increased regulatory infrastructure program revenues at Atlanta Gas Light, as well as lower operating expenses, primarily due to lower depreciation expense at Nicor Gas.
- A $3 million pre-tax gain from the renegotiated five-year earn-out provision related to the Compass Energy sale in 2013.
- Mark-to-market hedge gains at wholesale services during the current quarter compared to mark-to-market hedge losses for the same period in 2013.

In the first nine months of 2014, our net income attributable to AGL Resources Inc. was $334 million, an increase of $116 million compared to the same period in 2013, which includes an $80 million after-tax loss from discontinued operations. For the first nine months of 2014, our net income from continuing operations was $428 million, an increase of $200 million compared to net income from continuing operations for the same period in 2013. This increase was primarily the result of the following:

- A benefit from significantly colder-than-normal weather in the first half of the year at most of our businesses as compared to slightly colder-than-normal weather in the same period last year. This cold weather contributed an additional $11 million of operating margin for distribution operations compared to the same period of 2013, primarily in Illinois. The weather also increased the operating margin for retail operations by $12 million compared to the same period of 2013, primarily related to Georgia.
- Excluding the favorable weather impacts at distribution operations and retail operations, we also achieved growth in our operating margins of $15 million in 2014 primarily as a result of our January and June 2013 acquisitions in our retail operations.
    - Additionally, we experienced natural gas market volatility that enabled us to capture value and increase wholesale services' operating margin by $318 million.
- These increases were partially offset by a decrease in margin at midstream operations due to a retained fuel true-up at one of our storage facilities as a result of naturally occurring shrinkage of the caverns, as well as lower contracted firm rates at Jefferson Island and Central Valley.
- Higher incentive compensation expenses primarily related to higher earnings in 2014, increased outside services and other expenses at retail operations, and the $11 million pre-tax gain on sale of Compass Energy in the second quarter of 2013.
- Our income tax expense from continuing operations increased by $117 million for the first nine months of 2014 compared to the same period of 2013, primarily due to higher consolidated earnings.

Several of our business objectives are as follows:

- Distribution Operations: Invest necessary capital to enhance and maintain safety and reliability; remain a low-cost leader within the industry; opportunistically expand the system and capitalize on potential customer conversions. We intend to continue investing in our regulatory infrastructure programs in Georgia, Virginia, New Jersey and Tennessee to minimize regulatory lag and the recovery cycle. The state regulatory commissions have increased their focus on pipeline integrity, which may require additional costs to replace or repair some or our natural gas infrastructure. We continue to manage costs effectively and leverage our shared services model across our businesses to largely overcome inflationary effects.

Nicor Gas In 2013 Illinois enacted legislation that will allow Nicor Gas to provide more widespread safety and reliability enhancements to its distribution system. The legislation stipulates that rate increases to customer bills as a result of any infrastructure investments shall not exceed an annual average of 4.0% of base rate revenues. In July 2014 the Illinois Commission approved our Investing in Illinois Rider (previously known as Qualified Infrastructure Plant) that allows us to implement rates under the program effective in January 2015. Our filing included cost estimates for three years of $171 million in 2015, $173 million in 2016 and $171 million in 2017.

Atlanta Gas Light In accordance with an order issued by the Georgia Commission, when AGL Resources makes a business acquisition that reduces the costs allocated or charged to Atlanta Gas Light for shared services, the net savings to Atlanta Gas Light will be shared equally between the firm customers of Atlanta Gas Light and our shareholders for a 10-year period. In December 2013 we filed a Report of Synergy Savings with the Georgia Commission in connection with the Nicor Inc. acquisition. If and when approved, the net savings are expected to result in annual rate reductions to the firm customers of Atlanta Gas Light of $5 million.

Virginia Natural Gas In April 2014 the Governor of Virginia signed into law legislation that enables the state's natural gas utilities, including Virginia Natural Gas, to acquire long-term supplies of natural gas and make capital investments to facilitate the delivery of low-cost shale and coal-bed methane gas to Virginia homeowners and businesses. Under the terms of the new statute, Virginia Natural Gas could enter into commercial agreements to obtain up to 25% of its annual firm sales demand for natural gas through long-term contracts or investments such as purchases of reserves. Recovery on investments would be based upon the utility's authorized return on rate base, which would flow through the purchased gas adjustment mechanism or a similar mechanism, and approval in advance by the Virginia Commission. The new statute will also allow us to build pipelines and other infrastructure that deliver shale and coal-bed methane gas into the state's markets that seek to reduce natural gas supply costs or reduce price volatility for consumers, if approved by the Virginia Commission.

- Retail Operations: Maintain operating margin in Georgia and Illinois while continuing to expand into other profitable retail markets; integrate our warranty businesses and expand our overall market reach through partnership opportunities with our affiliates. With the continued adoption of fixed-price plans, we expect the Georgia retail market to remain highly competitive; however, our operating margins are forecasted to remain stable with modest growth from the acquisitions completed in 2013 and expansion into new markets.

- Wholesale Services: Maximize strong storage and transportation positions, including the creation of additional economic value in 2014; effectively perform on existing asset management agreements, expand customer base and maintain cost structure in line with market fundamentals. We anticipate low volatility in certain areas of our portfolio; however, we expect a continuation of volatility in the supply-constrained Northeast corridor in the near-term. We continue to position our business model to secure sufficient supplies of natural gas to meet the needs of our utility customers and to hedge natural gas prices to manage costs effectively, reduce price volatility and maintain a competitive advantage. We experienced increased natural gas price volatility that enabled us to capture value in wholesale services. As a result, wholesale services' operating margin for the first nine months of 2014 was $318 million higher than the same period in 2013. Wholesale services operating margin for the first nine months of 2014 also includes $37 million related to year-to-date transportation and forward commodity derivative losses associated with October 2014 and forward transportation capacity. This is compared to $31 million of similar transportation derivative losses in the first nine months of 2013 related to October 2013 and forward transportation capacity.

- Midstream Operations: Optimize our storage portfolio, including contracts that have expired or will expire, pursue LNG transportation and natural gas pipeline opportunities and evaluate alternate uses for our storage facilities. In 2014, we announced three pipeline agreements that we expect to provide a diverse source of natural gas to our customers in Georgia, New Jersey and Virginia. Subject to regulatory approvals and other conditions, construction is expected to begin in the 2016-2017 timeframe with completion targeted in 2017-2018.

The Dalton Pipeline will connect with the Transco pipeline system and provide additional natural gas supply to our customers in Georgia. We entered into an agreement to lease our 50% ownership in this lateral pipeline extension once it is placed in service. For additional information, see Note 2.

The PennEast Pipeline is a joint venture to construct and operate a natural gas pipeline that will transport low-cost natural gas from the Marcellus Shale area to our customers in New Jersey. We believe this will alleviate takeaway constraints in the Marcellus region and help mitigate some of the price volatility experienced during the past winter.

The Atlantic Coast Pipeline is a joint venture to construct and operate a natural gas pipeline that will run from West Virginia through Virginia and into eastern North Carolina to meet the region's growing demand for natural gas. The proposed pipeline project is expected to transport natural gas to our customers in Virginia. See Note 9 of our unaudited Condensed Consolidated Financial Statements under Part I, Item 1 herein and the following table for additional information.

Dollars in millions	Miles of Pipe	Expected capital expenditures (1)	Ownership Interest (1)	Scheduled year of completion
Dalton Pipeline	106	$ 210	50 %	2017
PennEast Pipeline	108	200	20 %	2017
Atlantic Coast Pipeline	550	260	5 %	2018
Total	764	$ 670		

(1) Represents our expected capital expenditures and ownership interest, which may change.

Natural Gas Market Fundamentals Volatility in the natural gas market arises from a number of factors, such as weather fluctuations or changes in supply or demand for natural gas in different regions of the country. The volatility of natural gas commodity prices has a significant impact on our customer rates, our long-term competitive position against other energy sources and the ability of retail operations and wholesale services to capture value from location and seasonal spreads. Additionally, changes in commodity prices subject a significant portion of our operations to earnings variability.

While natural gas supply increased during the 2013/2014 Heating Season in the U.S., it was not enough to meet the increased demand, resulting in the lowest storage levels in over a decade. Assuming normal weather during the next year, higher natural gas prices may occur as storage levels are restored.

Our non-utility businesses principally use physical and financial arrangements to reduce the risks associated with both weather-related seasonal fluctuations in market conditions and changing commodity prices. Additionally, our hedging strategies and physical natural gas supplies in storage enable us to reduce earnings risk exposure due to higher gas costs. These economic hedges may not qualify, or may not be designated, for hedge accounting treatment. As a result, our reported earnings for the wholesale services, retail operations and midstream operations segments reflect changes in the fair values of certain derivatives. Accordingly, a decline in natural gas prices or decreases in transportation spreads generally results in derivative gains and corresponding increases in EBIT, while an increase in natural gas prices or a widening of transportation spreads generally results in derivative losses and corresponding decreases in EBIT. These values may change significantly from period to period and are reflected as gains or losses within our operating revenues or our OCI for those derivative instruments that qualify and are designated as accounting hedges.

Results of Operations

We generate the majority of our operating revenues through the sale, distribution and storage of natural gas. We include in our consolidated revenues an estimate of revenues from natural gas distributed, but not yet billed to residential, commercial and industrial customers from the date of the last bill to the end of the reporting period. No individual customer or industry accounts for a significant portion of our revenues.

The operating revenues and EBIT of distribution operations and retail operations are seasonal. During the Heating Season, natural gas usage and operating revenues are generally higher as more customers are connected to our distribution systems and natural gas usage is higher in periods of colder weather. Our base operating expenses, excluding cost of gas, revenue taxes, interest expense and certain incentive compensation costs, are incurred relatively evenly over any given year. Thus, our operating results vary significantly from quarter to quarter as a result of seasonality.

We evaluate segment performance using the measures of EBIT and operating margin. EBIT includes operating income and other income and expenses. Items that we do not include in EBIT are financing costs (including interest) and income taxes, each of which we evaluate on a consolidated basis. Operating margin is a non-GAAP measure that is calculated as operating revenues minus cost of goods sold and revenue tax expense in distribution operations. Operating margin excludes operation and maintenance expense, depreciation and amortization, certain taxes other than income taxes, and the gain or loss on the sale of our assets, if any. These items are included in our calculation of operating income as reflected in our unaudited Condensed Consolidated Statements of Income.

We believe operating margin is a better indicator than operating revenues of the contribution resulting from customer growth in distribution operations, since the cost of goods sold and revenue tax expenses can vary significantly and are generally billed directly to our customers. We also consider operating margin to be a better indicator in retail operations, wholesale services and midstream operations, since it is a direct measure of earnings generated before overhead costs. You should not consider operating margin 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 may not be comparable to similarly titled measures of other companies.

The following table reconciles operating revenue and operating margin to operating income, and EBIT to income before income taxes and net income, together with other consolidated financial information for the periods presented.

	Three months ended September 30,			Nine months ended September 30,		
In millions, except per share amounts	2014	2013 (1)	Change	2014 (1)	2013 (1)	Change
Operating revenues	$ 589	$ 574	$ 15	$ 3,940	$ 2,991	$ 949
Cost of goods sold	(198)	(174)	(24)	(2,000)	(1,447)	(553)
Revenue tax expense (2)	(9)	(8)	(1)	(101)	(81)	(20)
Operating margin	382	392	(10)	1,839	1,463	376
Operating expenses	(316)	(330)	14	(1,134)	(1,082)	(52)
Revenue tax expense (2)	9	8	1	101	81	20
Gain on disposition of assets	3	-	3	3	11	(8)
Operating income	78	70	8	809	473	336
Other income	3	7	(4)	8	18	(10)

EBIT	81		77		4		817		491		326	
Interest expenses	(44)		(37)		(7)		(135)		(126)		(9)	
Income before income taxes	37		40		(3)		682		365		317	
Income tax expenses	(14)		(16)		2		(254)		(137)		(117)	
Income from continuing operations	23		24		(1)		428		228		200	
(Loss) income from discontinued operations, net of tax	(31)		1		(32)		(80)		1		(81)	
Net (loss) income	(8)		25		(33)		348		229		119	
Less net income attributable to the noncontrolling interest	-		-		-		14		11		3	
Net (loss) income attributable to AGL Resources Inc.	$ (8)		$ 25		$ (33)		$ 334		$ 218		$ 116	
Diluted earnings (loss) per common share information (3)												
Continuing operations	$ 0.19		$ 0.20		$ (0.01)		$ 3.47		$ 1.85		$ 1.63	
Discontinued operations (4)	(0.25)		0.01		(0.26)		(0.67)		0.01		(0.68)	
Diluted (loss) earnings per common share attributable to AGL Resources Inc. common shareholders	$ (0.06)		$ 0.21		$ (0.27)		$ 2.80		$ 1.86		$ 0.95	

(1) Amounts revised and or include prior period adjustments. For more information see Note 13 to our unaudited Condensed Consolidated Financial Statements under Part I, Item 1 herein.

(2) Adjusted for Nicor Gas' revenue tax expenses, as they are passed directly through to customers.

(3) Excludes net income attributable to the noncontrolling interest.

(4) In September 2014 we closed on the sale of Tropical Shipping. For more information see Note 12 to our unaudited Condensed Consolidated Financial Statements under Part I, Item 1 herein.

Operating Metrics

Weather We measure the effects of weather on our business through Heating Degree Days. Generally, increased Heating Degree Days result in higher demand for natural gas on our distribution systems. With the exception of Nicor Gas and Florida City Gas, we have various regulatory mechanisms, such as weather normalization, which limit our exposure to weather changes within typical ranges in each of our utilities' respective service areas. However, our customers in Illinois and our retail operations customers in Georgia can be impacted by warmer- or colder-than-normal weather. We have presented the Heating Degree Day information for those locations in the following table.

	Nine months ended September 30,			2014 vs. 2013 colder		2014 vs. normal colder	
	Normal	2014	2013				
Illinois (1) (2)	3,667	4,453	3,922	14	%	21	%
Georgia (1)	1,585	1,879	1,640	15	%	19	%

(1) Normal represents the 10-year average from January 1, 2004, through September 30, 2013, for Illinois at Chicago Midway International Airport, and for Georgia at Atlanta Hartsfield-Jackson International Airport as obtained from the National Oceanic and Atmospheric Administration, National Climatic Data Center.

(2) The 10-year average Heating Degree Days for the period, as established by the Illinois Commission in our last rate case, is 3,580 for the first nine months from 1998 through 2007.

For our weather risk associated with Nicor Gas, we implemented a corporate weather hedging program in 2013 that utilizes OTC weather derivatives to reduce the risk of lower operating margins potentially resulting from decreased customer usage in the event of significantly warmer-than-normal weather in Illinois. We will continue to evaluate and use available methods to mitigate our exposure to weather in Illinois for future periods.

Customers The number of customers at distribution operations and energy customers at retail operations can be impacted by natural gas prices, economic conditions and competition from alternative fuels. Our energy customers at retail operations are primarily located in Georgia and Illinois. Our customer metrics highlight the average number of customers for which we provide services and are provided in the following table.

	Three months ended September 30,		2014 vs. 2013		Nine months ended September 30,		2014 vs. 2013	
In thousands	2014	2013	% change		2014	2013	% change	
Distribution operations	4,455	4,447	0.2	%	4,498	4,480	0.4	%
Retail operations								
Energy customers (1)	619	621	(0.3	)%	629	617	2	%
Service contracts (2)	1,166	1,168	(0.2	)%	1,188	1,110	7	%
Market share in Georgia	31 %	31 %	-	%	31 %	32 %	(3	)%

(1) Increase for the nine months ended September 30 primarily represents the addition of approximately 33,000 residential and commercial customer relationships acquired in Illinois in June 2013.

(2) Increase for the nine months ended September 30, 2014 primarily due to acquisition of approximately 500,000 contracts on January 31, 2013.

Our year-over-year consolidated utility customer growth rate was 0.4% for the nine months ended September 30, 2014. We anticipate overall utility customer growth trends for 2014 to continue improving based on an expectation of improvement in the economy and relatively low natural gas prices.

However, retail operations' market share in Georgia has decreased slightly primarily as a result of a highly competitive marketing environment, which we expect will continue for the foreseeable future. For the remainder of 2014, our retail operations segment intends to continue its efforts to enter into targeted markets and expand its energy customers and its service contracts. We anticipate this expansion will provide growth opportunities in future years.

Volumes Our natural gas volume metrics for distribution operations and retail operations, as shown in the following table, present the effects of weather and our customers' demand for natural gas compared to prior year. Wholesale services' daily physical sales volumes represent the daily average natural gas volumes sold to its customers.

	Three months ended September 30,		2014 vs. 2013		Nine months ended September 30,		2014 vs. 2013	
	2014	2013	% change		2014	2013	% change	
Distribution operations (In Bcf)								
Firm	72	71	1	%	539	487	11	%
Interruptible	25	27	(7	)%	78	83	(6	)%
Total	97	98	(1	)%	617	570	8	%
Retail operations (In Bcf)								
Georgia firm	3	3	-	%	28	26	8	%
Illinois	1	1	-	%	13	7	86	%
Other (including Florida, Maryland, New York and Ohio)	1	1	-	%	7	5	40	%
Wholesale services								
Daily physical sales (Bcf / day)	5.6	5.4	4	%	6.2	5.7	9	%

Within our midstream operations segment, our natural gas storage businesses seek to have a significant percentage of their working natural gas capacity under firm subscription, but also take into account current and expected market conditions. This allows our natural gas storage business to generate additional revenue during times of peak market demand for natural gas storage services, but retain some consistency with their earnings and maximize the value of the investments.

Our midstream operations storage business is cyclical, and the abundant supply of natural gas in recent years and the resulting lack of market and price volatility, have negatively impacted the profitability of our storage facilities. Consistent with our expectations, we had contracts expire on March 31, 2014 that were subscribed at lower prices as compared to prior years. We anticipate these lower natural gas prices to continue throughout 2014 as compared to historical averages. The prices for natural gas storage capacity are expected to increase as supply and demand quantities reach equilibrium as the economy improves, expected exports of LNG occur and/or natural gas demand increases in response to low prices and expanded uses for natural gas. As of the periods presented, the overall monthly average firm subscription rates per facility and amount of firm capacity subscription were as follows:

	September 30, 2014		September 30, 2013	
	Avg. rates (1)	Firm capacity under subscription(1)	Avg. rates (1)	Firm capacity under subscription (1)
Jefferson Island	$0.108	4.6	$0.122	5.6
Golden Triangle	0.114	5.0	0.240	2.0
Central Valley	0.062	2.5	0.130	3.0

(1) Rates are per dekatherm. Firm capacity under subscription excludes 7.0 Bcf contracted by Sequent as of September 30, 2014, at an average monthly rate of $0.050 and 3.5 Bcf as of September 30, 2013, at an average monthly rate of $0.091.

Segment Information Operating margin, operating expenses and EBIT information for each of our segments are contained in the following tables:

	Three months ended September 30, 2014			Three months ended September 30, 2013		
In millions	Operating margin (1) (2)	Operating expenses (2)	EBIT (1)	Operating margin (1) (2) (3)	Operating expenses (2)	EBIT (1)
Distribution operations	$ 327	$ 239	$ 89	$ 326	$ 253	$ 77
Retail operations	47	42	5	46	40	6
Wholesale services	2	11	(7)	12	14	(2)
Midstream operations	7	11	(4)	10	11	(1)
Other (4)	1	6	(2)	1	7	(3)
Intercompany elimination	(2)	(2)	-	(3)	(3)	-
Consolidated	$ 382	$ 307	$ 81	$ 392	$ 322	$ 77

	Nine months ended September 30, 2014	Nine months ended September 30, 2013
In millions	EBIT (1)	EBIT (1)

	Operating margin (1) (2)	Operating expenses (2)		Operating margin (1) (2)	Operating expenses (2)	
Distribution operations (3)	$ 1,218	$ 795	$ 428	$ 1,177	$ 801	$ 387
Retail operations (3)	231	129	102	203	117	86
Wholesale services	370	62	308	52	39	24
Midstream operations	21	36	(14)	33	34	1
Other (4)	5	17	(7)	5	17	(7)
Intercompany elimination	(6)	(6)	-	(7)	(7)	-
Consolidated (3)	$ 1,839	$ 1,033	$ 817	$ 1,463	$ 1,001	$ 491

(1) Operating margin is a non-GAAP measure. A reconciliation of operating revenue and operating margin to operating income, and EBIT to income before income taxes and net income is contained in “Results of Operations” herein. See Note 11 to our unaudited Condensed Consolidated Financial Statements under Part I, Item 1 herein for additional segment information.

(2) Operating margin and operating expenses are adjusted for revenue tax expenses, which are passed directly through to our customers.

(3) 2013 amounts revised for prior period adjustments and the nine months ended 2014 includes revisions for the first six months of 2014. For more information, see Note 13 to our unaudited Condensed Consolidated Financial Statements under Part I, Item 1 herein.

(4) Our other segment includes our investment in Triton, which was formerly part of our cargo shipping segment that is now classified as discontinued operations. For more information, see Note 12 to our unaudited Condensed Consolidated Financial Statements under Part I, Item 1 herein.

Distribution Operations

Our distribution operations segment is the largest component of our business and is subject to regulation and oversight by agencies in each of the seven states we serve. These agencies approve natural gas rates designed to provide us the opportunity to generate revenues to recover the cost of natural gas delivered to our customers and our fixed and variable costs, such as depreciation, interest, maintenance and overhead costs, and to earn a reasonable return for our shareholders.

With the exception of Atlanta Gas Light, our second-largest utility, the earnings of our regulated utilities can be affected by customer consumption patterns that are a function of weather conditions, price levels for natural gas and general economic conditions that may impact our customers’ ability to pay for natural gas consumed. Depreciation expense at distribution operations decreased for the three and nine months ended September 30, 2014, by $10 million and $30 million, respectively, primarily due to Nicor Gas’ new composite depreciation rate that became effective August 30, 2013, partially offset by capital investments. Nicor Gas’ lower composite depreciation rate did not impact customer rates. For the three and nine months ended September 30, 2014, distribution operations’ EBIT increased by $12 million and $41 million, or 16% and 11%, respectively, compared to the same periods during the prior year, as shown in the following table.

In millions	Three months ended	Nine months ended (1)
EBIT - for September 30, 2013 (1)	$77	$387
Operating margin		
Increased operating margin mainly driven by colder-than-normal weather in the first quarter, higher customer usage and customer growth compared to prior year	3	28
(Decreased) increased rider revenues primarily as a result of bad debt and energy efficiency program recoveries at Nicor Gas	(4)	5
Increased revenues from regulatory infrastructure replacement programs, primarily at Atlanta Gas Light (1)	2	8
Increase in operating margin	1	41
Operating expenses		
Increased payroll and variable compensation costs as a result of merit increases, overtime costs related to colder-than-normal weather, higher earnings and the seasonality of earnings	1	21
Increased outside services primarily from costs related to weather, and increased other expenses	3	8
Decreased depreciation expense primarily due to the impact of Nicor Gas' new composite depreciation rate (1)	(10)	(30)
(Decreased) increased rider expenses primarily as a result of energy efficiency program expenses at Nicor Gas (1)	(4)	5
Decreased pension and health benefits expenses primarily related to retiree health care costs and change in actuarial gains and losses	(4)	(10)
Decrease in operating expenses	(14)	(6)
Decreased AFUDC equity from STRIDE projects at Atlanta Gas Light	(3)	(6)
EBIT - for September 30, 2014	$89	$428

(1) 2013 EBIT amounts revised for prior period adjustments and the nine months ended September 30, 2014 includes revisions for the first six months of 2014. For more information, see Note 13 to our unaudited Condensed Consolidated Financial Statements under Part I, Item 1 herein.

Retail Operations

Our retail operations segment, which consists of SouthStar and Pivotal Home Solutions, is weather sensitive and uses a variety of hedging strategies, such as weather derivative instruments and other risk management tools, to mitigate potential weather impacts. For the three months ended September 30, 2014, retail operations' EBIT decreased by $1 million, or 17%, compared to the same period last year and increased by $16 million, or 19%, for the nine months ended September 30, 2014, compared to the same period during the prior year, as shown in the following table.

In millions	Three months ended	Nine months ended (1)
EBIT - for September 30, 2013 (1)	$ 6	$ 86
Operating margin		
Increased margin primarily due to retail acquisitions in January and June 2013	-	15
Increased margin primarily related to average customer usage in Georgia due to colder-than-normal weather and increased demand relative to prior year, net of weather hedges	-	10
Increased margin in Illinois mainly due to weather and hedge gains	2	4

LOCOM adjustment	(1)	(1)
Increase in operating margin	1	28
Operating expenses		
Increased variable compensation expense related to higher earnings in the first quarter of 2014, and increased outside services and other expenses	4	9
(Decreased) increased bad debt expenses primarily related to colder-than-normal weather and higher natural gas prices	(1)	1
(Decreased) increased expenses primarily due to retail acquisitions in January and June 2013	(1)	2
Increase in operating expenses	2	12
EBIT - for September 30, 2014	$ 5	$ 102

(1) 2013 EBIT amounts revised for prior period adjustments and the nine months ended September 30, 2014 includes revisions for the first six months of 2014. For more information, see Note 13 to our unaudited Condensed Consolidated Financial Statements under Part I, Item 1 herein.

Wholesale Services

Our wholesale services segment is involved in asset management and optimization, storage, transportation, producer and peaking services, natural gas supply, natural gas services and wholesale marketing. Sequent has positioned the business to generate positive economic earnings even under low volatility market conditions. However, when market price volatility increases as we experienced in 2014, we believe Sequent is well positioned to capture significant value and generate stronger results. EBIT for wholesale services is impacted by volatility in the natural gas market arising from a number of factors, including weather fluctuations and changes in supply or demand for natural gas in different regions of the country. For the three months ended September 30, 2014, wholesale services' EBIT decreased by $5 million compared to the same period last year and increased by $284 million for the nine months ended September 30, 2014, compared to the same periods during the prior year, as shown in the following table.

In millions	Three months ended	Nine months ended
EBIT - for September 30, 2013	$(2)	$24
Operating margin		
Change in commercial activity largely driven by the transportation and storage portfolios in the Northeast and Midwest	(25)	337
Change in value on storage derivatives as a result of changes in NYMEX natural gas prices	-	(9)
Change in value on transportation and forward commodity derivatives from price movements related to natural gas transportation positions	18	(6)
Change in LOCOM adjustment, net of derivative recoveries	(3)	-
Decreased operating margin due to sale of Compass Energy in May 2013	-	(4)
(Decrease) increase in operating margin	(10)	318
Operating expenses		
(Decreased) increased incentive compensation costs at Sequent due to higher operating revenues in the first half of 2014, slightly offset by increased outside services and other costs	(3)	25
Decreased expenses due to sale of Compass Energy in May 2013	-	(2)
(Decrease) increase in operating expenses	(3)	23
Increase (decrease) in other income, primarily related to the gain on sale of Compass Energy	2	(11)
EBIT - for September 30, 2014	$(7)	$308

The following table illustrates the components of wholesale services' operating margin for the periods presented.

	Three months ended September 30,		Nine months ended September 30,	
In millions	2014	2013	2014	2013
Commercial activity recognized	$ 2	$ 27	$ 412	$ 79
Gain on storage derivatives	2	2	-	9
Gain (loss) on transportation and forward commodity derivatives	2	(16)	(37)	(31)
Inventory LOCOM adjustment, net of estimated current period recoveries	(4)	(1)	(5)	(5)
Operating margin	$ 2	$ 12	$ 370	$ 52

Change in commercial activity The commercial activity at wholesale services includes recognized storage and transportation values that were generated in prior periods, which reflect the impact of prior period derivative gains and losses as associated physical transactions occur in the period. For the three months ended September 30, 2014, the change in commercial activity was due primarily to tightening of locational (transportation) and seasonal (storage) spreads associated with natural gas transportation and storage markets, particularly in the Northeast region of the U.S., compared to the same period last year, in part driven by changes in natural gas production and new pipeline capacity. Further, commercial activity was negatively impacted by lower gas-fired generation sales due to milder weather in the current quarter. For the first nine months of 2014, commercial activity increased significantly due to the following:

- the recognition of significantly higher operating margin associated with our transportation and storage portfolios, particularly in the Northeast and Midwest regions, from price volatility generated by significantly colder-than-normal weather in the first quarter of 2014, in part reflecting Sequent's strategy and focus on providing asset management and related services to producers around the major shale producing regions and to natural gas-fired power generators, enabling Sequent to optimize the associated pipeline transportation and storage capacity assets,
- the recognition of operating margin resulting from the withdrawal of storage inventory at the end of 2013 that was included in the storage withdrawal schedule with a value of $28 million as of December 31, 2013; and
- the recognition of operating margin resulting from mark-to-market accounting derivative losses at the end of 2013.

Change in storage and transportation derivatives The first half of 2014 showed a return of significantly higher price volatility benefitting Sequent's portfolio of pipeline transportation and storage capacity assets throughout the country, primarily in the Gulf Coast, Northeast and Midwest markets. Although we do not expect this high level of price volatility to continue, we see the potential for market fundamentals indicating some level of increased volatility that would continue to benefit Sequent's portfolio of pipeline transportation capacity should this occur. Gains in our transportation and forward commodity hedge positions in the third quarter of 2014 are the result primarily of the tightening of transportation basis spreads that resulted in hedge gains in the third quarter. The storage derivative gains during the third quarter are primarily due to the change in natural gas prices applicable to the locations of our specific storage assets.

Losses in our transportation and forward commodity derivative positions for the first nine months of 2014 are the result primarily of widening transportation basis spreads. Significantly colder-than-normal weather and higher demand together with natural gas transportation constraints due to growing shale production impacted forward prices at natural gas receipt and delivery points, primarily in the Northeast and the Midwest regions, during the first half of 2014. These losses are temporary and, based on current expectations, largely will be recovered in the fourth quarter of 2014 and through 2015 with the physical flow of natural gas and utilization of the contracted transportation capacity.

Withdrawal schedule and physical transportation transactions The expected natural gas withdrawals from storage and expected recovery of derivative losses associated with Sequent's transportation portfolio are presented in the following table, along with the net operating revenues expected at the time of withdrawal from storage and the physical flow of natural gas between contracted transportation receipt and delivery points. Sequent's expected net operating revenues exclude storage and transportation demand charges, as well as other variable fuel, withdrawal, receipt and delivery charges, but are net of the estimated impact of profit sharing under our asset management agreements. The amounts that are realizable in future periods are based on the inventory withdrawal schedule, planned physical flow of natural gas between the transportation receipt and delivery points and forward natural gas prices at September 30, 2014. A portion of Sequent's storage inventory and transportation capacity is economically hedged with futures contracts, which results in realization of substantially fixed net operating revenues, timing notwithstanding. For more information on Sequent's energy marketing and risk management activities, see Item 7A, "Quantitative and Qualitative Disclosures About Market Risk - Commodity Price Risk" of our 2013 Form 10-K.

	Storage withdrawal schedule		Physical transportation transactions – expected net operating revenues (2)
Dollars in millions	Total storage (in Bcf) (WACOG $3.96)	Expected operating revenues (1)	
Fourth quarter 2014	16	$ 6	$ 12
2015	37	10	28
2016 and thereafter	3	2	(3)
Total at September 30, 2014 (3)	56	$ 18	$ 37
Total at December 31, 2013	36	$ 28	$ 73
Total at September 30, 2013	57	$ 23	$ 31

(1) Represents expected operating revenues from planned storage withdrawals associated with existing inventory positions and could change as Sequent adjusts its daily injection and withdrawal plans in response to changes in future market conditions and forward NYMEX price fluctuations.

(2) Represents the periods associated with the transportation derivative losses during which the derivatives will be settled and the physical transportation transactions will occur that offset the derivative losses recognized in 2013 and during the nine months of 2014.

(3) Includes 5 Bcf in storage with expected operating revenues of $4 million that is currently inaccessible due to operational issues at a third party storage facility. The owner of this third party storage facility is working to resolve these issues and has communicated to us that it expects the facility to be operational by mid-2015. While we expect this inventory to be fully recovered, the timing of withdrawal of this gas may be impacted by the operational issues.

The decline in storage roll-out value in part reflects the lower summer-to-winter storage spreads compared to last year, which we expect to continue in the near term. The unrealized storage and transportation derivative losses do not change the underlying economic value of our storage and transportation positions and, based on current expectations, will primarily be reversed in the fourth quarter of 2014 and 2015 when the related transactions occur and are

recognized. For more information on Sequent's energy marketing and risk management activities, see Item 7A "Quantitative and Qualitative Disclosures About Market Risk" under the caption "Natural Gas Price Risk" of our 2013 Form 10-K.

Midstream Operations

Our midstream operations segment's primary activity is operating non-utility storage and pipeline facilities, including the development and operation of high-deliverability underground natural gas storage and pipeline assets. While this business can also generate additional revenue during times of peak market demand for natural gas storage services, certain of our storage services are covered under short-, medium- and long-term contracts at fixed market rates. Based on an engineering study and mechanical integrity tests performed in 2014, we identified a lower amount of working gas capacity, further resulting in the true-up of retained fuel at one of our storage facilities, negatively impacting EBIT by $10 million for the nine months ended September 30, 2014. The decrease in working gas capacity is a result of naturally occurring shrinkage of the storage cavern, and we are developing strategies to recover the decreased working capacity. For the three and nine months ended September 30, 2014, midstream operations' EBIT decreased by $3 million and $15 million, respectively, compared to the same periods during the prior year, as shown in the following table.

In millions	Three months ended	Nine months ended
EBIT - for September 30, 2013	$ (1)	$ 1
Operating margin		
Decreased margin at one of our storage facilities related to true-up of retained fuel, partially offset on a year-to-date basis by higher interruptible operating margins largely at Golden Triangle in the first quarter of 2014 due to optimizing the facilities during the colder weather in 2014	(1)	(7)
Decreased margin at Jefferson Island and Central Valley as a result of lower subscription rates as well as lower revenues from LNG sales	(2)	(5)
Decrease in operating margin	(3)	(12)
Operating expenses		
Increased maintenance, outside service costs, depreciation expense and other	-	2
Increase in operating expenses	-	2
Decrease in other income from equity investment in Horizon Pipeline	-	(1)
EBIT - for September 30, 2014	$ (4)	$ (14)

Liquidity and Capital Resources

Overview The acquisition of natural gas and pipeline capacity, payment of dividends and funding of working capital needs primarily related to our natural gas inventory are our most significant short-term financing requirements. The liquidity required to fund these short-term needs is primarily provided by our operating activities, and any needs not met are primarily satisfied with short-term borrowings under our commercial paper programs, which are supported by the AGL Credit Facility and the Nicor Gas Credit Facility. The need for long-term capital is driven primarily by capital expenditures and maturities of long-term debt. Periodically, we raise funds supporting our long-term cash needs from the issuance of long-term debt or equity securities. We regularly evaluate our funding strategy and profile to ensure that we have sufficient liquidity for our short-term and long-term needs in a cost-effective manner.

Our financing activities, including long-term and short-term debt and equity, are subject to customary approval or review by state and federal regulatory bodies, including the various commissions of the states in which we conduct business. Certain financing activities we undertake may also be subject to approval by state regulatory agencies. A substantial portion of our consolidated assets, earnings and cash flows 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. Nicor Gas is restricted by regulation to the extent of its retained earnings balance in the amount it can dividend and is not permitted to make money pool loans to affiliates.

We believe the amounts available to us under our long-term debt and credit facilities as well as through the issuance of debt and equity securities, combined with cash provided by operating activities and the proceeds received from the sale of Tropical Shipping, will continue to allow us to meet our needs for working capital, pension and retiree welfare benefits, capital expenditures, anticipated debt redemptions, interest payments on debt obligations, dividend payments and other cash needs through the next several years. However, considering our upcoming January 2015 maturity of $200 million of senior notes and our recently announced pipeline agreements, we may issue additional long-term debt as our financing needs and market conditions warrant.

Our ability to satisfy our working capital requirements and our debt service obligations, or fund planned capital expenditures, will substantially depend upon our future operating performance (which will be affected by prevailing economic conditions), and financial, business and other factors, some of which we are unable to control. These factors

include, among others, regulatory changes, the price of and demand for natural gas and operational risks.

Our capitalization and financing strategy is intended to ensure that we are properly capitalized with the appropriate mix of debt securities and equity. This strategy includes active management of the percentage of total debt relative to total capitalization, as well as the term and interest rate profile of our debt securities, and maintenance of an appropriate mix of debt with fixed and floating interest rates (our variable-rate debt target is 20% to 45% of total debt). At September 30, 2014, our variable-rate debt was 20% of our total debt, compared to 28% as of December 31, 2013, and 23% as of September 30, 2013. The decrease from December 31, 2013, was primarily due to decreased commercial paper borrowings.

Our objective continues to be to maintain our strong balance sheet and liquidity profile, solid investment grade ratings and our annual dividend growth. Additionally, 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, acquisitions and other factors. See Item 1A, “Risk Factors,” in our 2013 Form 10-K for additional information on items that could impact our liquidity and capital resource requirements.

Capital Projects We continue to focus on capital discipline and cost control while moving ahead with projects and initiatives that we expect will have current and future benefits to us and our customers, provide an appropriate return on invested capital and ensure the safety, reliability and integrity of our utility infrastructure. The following table and discussions provide updates on some of our larger capital projects under various programs in our distribution operations segment. These programs update or expand our distribution systems to improve system reliability and meet operational flexibility and growth. Our anticipated expenditures for these programs in 2014 are discussed in "Liquidity and Capital Resources" under the caption 'Cash Flow from Investing Activities' under Item 7 in our 2013 Form 10-K/A.

Dollars in millions STRIDE program	Utility	Expenditures in 2014	Expenditures since project inception	Miles of pipe installed	Year project began	Scheduled year of completion
Integrated System Reinforcement Program (i-SRP)	Atlanta Gas Light	$ 8	$ 259	n/a	2009	2017
Integrated Customer Growth Program (i-CGP)	Atlanta Gas Light	3	43	n/a	2010	2017
Integrated Vintage Plastic Replacement Program (i-VPR)	Atlanta Gas Light	46	51	142	2013	2017
Enhanced infrastructure program	Elizabethtown Gas	23	139	129	2009	2017
Accelerated infrastructure replacement program (SAVE)	Virginia Natural Gas	18	58	115	2012	2017
Total		$ 98	$ 550	386		

Short-Term Debt Our short-term debt comprises borrowings under our commercial paper programs and current portion of our senior notes. Our commercial paper borrowings are supported by the $1.3 billion AGL Credit Facility and $700 million Nicor Gas Credit Facility. The Nicor Gas Credit Facility can only be used for the working capital needs of Nicor Gas. The following table provides additional information on our short-term debt.

In millions	Period end balance outstanding (1)	Daily average balance outstanding (2)	Minimum balance outstanding (2)	Largest balance outstanding (2)
Commercial paper - AGL Capital	$ 292	$ 381	$ -	$ 1,006
Commercial paper - Nicor Gas	389	217	58	393
Senior notes (3)	200	190	-	200
Total short-term debt and current portion of long-term debt	$ 881	$ 788	$ 58	$ 1,599

(1) As of September 30, 2014.

(2) For the nine months ended September 30, 2014. The minimum and largest balances outstanding for each debt instrument occurred at different times during the period. Consequently, the total balances are not indicative of actual borrowings on any one day during the period.

(3) These senior notes mature in January 2015.

The largest, minimum and daily average balances borrowed under our commercial paper programs are important when assessing the intra-period fluctuations of our short-term borrowings and potential liquidity risk. The fluctuations are

due to our seasonal cash requirements to fund working capital needs, in particular the purchase of natural gas inventory, margin calls and collateral posting requirements.

Increasing natural gas commodity prices can significantly impact our commercial paper borrowings. Based on current natural gas prices and our expected injection plan, a $1 NYMEX price increase could result in an approximately $24 million change of working capital requirements during the 2014 injection season. This range is sensitive to the timing of storage injections and withdrawals, collateral requirements and our portfolio position. Based upon our total debt outstanding as of September 30, 2014, and our maximum 70% debt to total capitalization allowed under our financial covenants, we could potentially borrow an additional $1 billion of commercial paper under the AGL Credit Facility and an additional $300 million of commercial paper under the Nicor Gas Credit Facility. As a result, based on current natural gas prices and our expected purchases during the remainder of the injection season, we believe that we have sufficient liquidity to cover our working capital needs for the upcoming Heating Season.

Credit Ratings Our borrowing costs and our ability to obtain adequate and cost-effective financing are directly impacted by our credit ratings, as well as the availability of financial markets. Credit ratings are important to our counterparties when we engage in certain transactions, including OTC derivatives. It is our long-term objective to maintain or improve our credit ratings in order to manage our existing financing costs and enhance our ability to raise additional capital on favorable terms.

Credit ratings and outlooks are opinions subject to ongoing review by the rating agencies and may periodically change. The rating agencies regularly review our performance and financial condition and reevaluate their ratings of our long-term debt and short-term borrowings, our corporate ratings and our ratings outlook. There is no guarantee 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. A credit rating is not a recommendation to buy, sell or hold securities, and each rating should be evaluated independently of other ratings.

Factors we consider important to assessing our credit ratings include our Consolidated Statements of Financial Position, leverage, capital spending, earnings, cash flow generation, available liquidity and overall business risks. We do not have any triggering 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 September 30, 2014, and reflects no change from what was reported in our 2013 Form 10-K/A.

	AGL Resources			Nicor Gas		
	S&P	Moody's	Fitch	S&P	Moody's	Fitch
Corporate rating	BBB+	n/a	BBB+	BBB+	n/a	A
Commercial paper	A-2	P-2	F2	A-2	P-1	F1
Senior unsecured	BBB+	A3	BBB+	BBB+	A2	A+
Senior secured	n/a	n/a	n/a	A	Aa3	AA-
Ratings outlook	Stable	Stable	Stable	Stable	Stable	Stable

A downgrade in our current ratings, particularly below investment grade, would increase our borrowing costs and could limit our access to the commercial paper market. 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 could decrease.

Default Provisions Our debt instruments and other financial obligations include provisions that, if not complied with, could require early payment or similar actions. Our credit facilities contain customary events of default, including, but not limited to, the failure to comply with certain affirmative and negative covenants, cross-defaults to certain other material indebtedness and a change of control.

Our credit facilities contain certain non-financial covenants that, among other things, restrict liens and encumbrances, loans and investments, acquisitions, dividends and other restricted payments, asset dispositions, mergers and consolidations, and other matters customarily restricted in such agreements.

Our credit facilities each include a financial covenant that requires us to maintain a ratio of total debt to total capitalization of no more than 70% at the end of any fiscal month. However, we typically seek to maintain these ratios at levels between 50% and 60%, except for temporary increases related to the timing of acquisition and financing activities. Adjusting for these items, the following table contains our debt-to-capitalization ratios for the dates presented, which are below the maximum allowed. We were in compliance with all of our debt provisions and covenants, both financial and non-financial, for all periods presented.

	AGL Resources			Nicor Gas		
	Sep. 30, 2014	Dec. 31, 2013	Sep. 30, 2013	Sep. 30, 2014	Dec. 31, 2013	Sep. 30, 2013
Debt-to-capitalization ratio as calculated from our unaudited Condensed Consolidated Statement of Financial Position	54 %	58 %	57 %	57 %	54 %	50 %
Adjustments (1)	(1)	(1)	(1)	-	1	-
Debt-to-capitalization ratio as calculated within our credit facilities	53 %	57 %	56 %	57 %	55 %	50 %

(1) As defined in credit facilities, includes standby letters of credit, performance/surety bonds and excludes accumulated OCI items related to non-cash pension adjustments, other post-retirement benefits liability adjustments and accounting adjustments for cash flow hedges.

Cash Flows The following table provides a summary of our operating, investing and financing cash flows for the periods presented.

In millions	Nine months ended September 30, 2014	2013	Variance
Net cash provided by (used in) (1):			
Operating activities	$874	$1,070	$196
Investing activities	(284)	(661)	377
Financing activities	(663)	(409)	(254)
Net increase (decrease) in cash and cash equivalents - continuing operations	(50)	(11)	(39)
Net (decrease) increase in cash and cash equivalents - discontinued operations	(23)	11	(34)
Cash and cash equivalents (including held for sale) at beginning of period	105	131	(26)
Cash and cash equivalents (including held for sale) at end of period	32	131	(99)
Less cash and cash equivalents held for sale at end of period	-	34	(34)
Cash and cash equivalents (excluding held for sale) at end of period	$32	$97	$(65)

(1) Includes activity for discontinued operations.

Cash Flow from Operating Activities The $196 million decrease in cash provided by operating activities resulted primarily from (i) trade payables, other than energy marketing, due to higher accrued volumes in December 2013 compared to December 2012, and (ii) deferred natural gas costs, due to an increase in the price paid for natural gas in the first half of 2014 associated with the extremely cold weather. This decrease in cash provided by operating activities was largely offset by increases in cash from operating activities for the nine months ended September 30, 2014, compared to the same period in 2013 primarily related to increased cash provided by (i) higher earnings year over year largely attributed to significantly colder-than-normal weather in the current year and increased price volatility that enabled us to capture value in wholesale services, (ii) inventories due to increased withdrawals at our distribution and midstream operations, partially offset by a decrease in withdrawals at Sequent, and (iii) net energy marketing receivables and payables, due to higher cash received in 2014 that related to December 2013.

Cash Flow from Investing Activities The $375 million decrease in cash flow used in investing activities was primarily the result of $225 million proceeds from the sale of Tropical Shipping during the third quarter of 2014. The decrease in cash flow used in investing activities was also impacted favorably by the $122 million spending on the acquisition of approximately 500,000 service plans during the first quarter of 2013. This decrease was partially offset by increased spending for PP&E expenditures of $17 million.

Cash Flow from Financing Activities The increased use of cash for our financing activities for the nine months ended September 30, 2014, compared to the same period in 2013 was primarily the result of our issuance of senior notes in May 2013 and recovery of working capital at wholesale services, partially offset by lower commercial paper repayments due to higher working capital needs at distribution operations. For more information on our debt, see Note 7 to our unaudited Condensed Consolidated Financial Statements under Part I, Item 1 herein.

Contractual Obligations and Commitments We have incurred various contractual obligations and financial commitments in the normal course of business that are reasonably likely to have a material effect on liquidity or the availability of requirements for 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. 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. For additional information see Note 10 to our unaudited Condensed Consolidated Financial Statements under Part I, Item 1 herein. The following table illustrates our expected future contractual payments under our obligations and other commitments as of September 30, 2014.

In millions	Total	2014	2015	2016	2017	2018	2019 & thereafter
Recorded contractual obligations:							
Long-term debt (1)	$3,706	$-	$200	$545	$22	$155	$2,784
Short-term debt	681	681	-	-	-	-	-
Environmental remediation liabilities (2)	454	16	83	104	50	38	163
Pipeline replacement program costs (2)	1	1	-	-	-	-	-
Total	$4,842	$698	$283	$649	$72	$193	$2,947
Unrecorded contractual obligations and commitments (3) (8):							
Pipeline charges, storage capacity and gas supply (4)	$3,837	$304	$564	$292	$185	$174	$2,318
Interest charges (5)	2,798	36	179	171	147	146	2,119

Operating leases (6)	207	11	35	31	24	18	88
Asset management agreements (7)	31	2	9	8	6	4	2
Standby letters of credit, performance/surety bonds (8)	27	9	17	1	-	-	-
Other	9	1	3	3	1	1	-
Total	$6,909	$363	$807	$506	$363	$343	$4,527

(1) Excludes the $77 million step up to fair value of first mortgage bonds, $16 million unamortized debt premium and $6 million interest rate swaps fair value adjustment. Includes current portion of long-term debt of $200 million, which matures in January 2015.

(2) Includes charges recoverable through base rates or rate rider mechanisms.

(3) In accordance with GAAP, these items are not reflected in our unaudited Condensed Consolidated Statements of Financial Position.

(4) Includes charges recoverable through a natural gas cost recovery mechanism or alternatively billed to Marketers and demand charges associated with Sequent. The gas supply balance includes amounts for Nicor Gas and SouthStar gas commodity purchase commitments of 66 Bcf at floating gas prices calculated using forward natural gas prices as of September 30, 2014, and is valued at $271 million. As we do for other subsidiaries, we provide guarantees to certain gas suppliers for SouthStar in support of payment obligations.

(5) Floating rate interest charges are calculated based on the interest rate as of September 30, 2014, and the maturity date of the underlying debt instrument. As of September 30, 2014, we have $42 million of accrued interest on our unaudited Condensed Consolidated Statements of Financial Position that will be paid in the next 12 months.

(6) We have certain operating leases with provisions for step rent or escalation payments and certain lease concessions. We account for these leases by recognizing the future minimum lease payments on a straight-line basis over the respective minimum lease terms, in accordance with GAAP. However, this lease accounting treatment does not affect the future annual operating lease cash obligations as shown herein. Our operating leases are primarily for real estate.

(7) Represent fixed-fee minimum payments for Sequent’s affiliated asset management agreements.

(8) We provide guarantees to certain municipalities and other agencies and certain gas suppliers of SouthStar in support of payment obligations.

Critical Accounting Policies and Estimates

The preparation of our financial statements in conformity with GAAP requires us to make estimates and judgments that affect the reported amounts in our unaudited Condensed Consolidated Financial Statements and accompanying notes. Those judgments and estimates have a significant effect on our financial statements, primarily due to the need to make estimates about the effects of matters that are inherently uncertain. Actual results could differ from those estimates. We frequently reevaluate our judgments and estimates that are based upon historical experience and various other assumptions that we believe to be reasonable under the circumstances.

Each of our critical accounting 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. Except as described below, there have been no significant changes to our critical accounting estimates from those disclosed in our Management's Discussion and Analysis of Financial Condition and Results of Operations as filed on our 2013 Form 10-K/A. Our critical accounting estimates used in the preparation of our unaudited Condensed Consolidated Financial Statements include the following:

- Accounting for Rate-Regulated Subsidiaries
- Derivatives and Hedging Activities
- Goodwill and Long-Lived Assets, including Other Intangible Assets
- Contingencies
- Pension and Other Retirement Plans
- Provisions for Income Taxes

Goodwill In the first quarter of 2014 we conducted an engineering study that indicated a reduction in our estimated working gas capacity for a storage facility from what was projected when our 2013 annual goodwill impairment analysis was performed in the fourth quarter of 2013. Given that the 2013 annual goodwill impairment test indicated that the estimated fair value of the storage and fuels reporting unit exceeded its carrying amount by less than 5%, we considered this reduced forecast of storage capacity as an indicator of potential impairment and, accordingly, conducted an interim goodwill impairment analysis during the first quarter of 2014. See "Goodwill" in Note 2 to our unaudited Condensed Consolidated Financial Statements under Part I, Item 1 herein for additional information.

Accounting Developments

See "Accounting Developments" in Note 2 to our unaudited Condensed Consolidated Financial Statements under Part I, Item 1 herein.

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 results from changes in the fair value of natural gas. Interest rate risk is caused by fluctuations in interest rates related to 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. We use derivative instruments to manage these risks. Our use of derivative instruments is governed by a risk management policy, approved and monitored by our Risk Management Committee (RMC), which prohibits the use of derivatives for speculative purposes.

Our 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 treatment for our derivative instruments are described in further detail in Note 5 of our unaudited Condensed Consolidated Financial Statements included herein.

Natural Gas Price Risk

The following tables include the fair values and average values of our consolidated derivative instruments as of the dates indicated. We base the average values on monthly averages for the nine months ended September 30, 2014 and 2013.

	Derivative instruments average values at September 30, (1)	
In millions	2014	2013
Asset	$ 144	$ 106
Liability	106	42

(1) Excludes cash collateral amounts.

In millions	Derivative instruments fair values netted with cash collateral at September 30, 2014	December 31, 2013	September 30, 2013
Asset	$113	$119	$112
Liability	47	80	44

The following table illustrates the change in the net fair value of our derivative instruments during the periods presented, and provides details of the net fair value of contracts outstanding as of the dates presented.

In millions	Three months ended September 30, 2014	2013	Nine months ended September 30, 2014	2013
Net fair value of derivative instruments outstanding at beginning of period	$(30)	$(3)	$(82)	$36
Derivative instruments realized or otherwise settled during period	(19)	(11)	24	(55)
Change in net fair value of derivative instruments	(10)	(12)	(1)	(7)
Net fair value of derivative instruments outstanding at end of period	(59)	(26)	(59)	(26)
Netting of cash collateral	125	94	125	94
Cash collateral and net fair value of derivative instruments outstanding at end of period	$66	$68	$66	$68

The sources of our net fair value at September 30, 2014, are as follows.

In millions	Prices actively quoted (Level 1) (1)	Significant other observable inputs (Level 2) (2)
Mature through 2014	$ (25)	$ 10
Mature 2015 - 2016	(41)	(1)
Mature 2017 - 2018	(2)	-
Total derivative instruments (3)	$ (68)	$ 9

(1) Valued using NYMEX futures prices.

(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.

VaR Our VaR may not be comparable to that of other entities due to differences in the factors used to calculate VaR. Our VaR is determined on a 95% confidence interval and a 1-day holding period, which means that 95% of the time, the risk of loss in a day from a portfolio of positions is expected to be less than or equal to the amount of VaR calculated. Our open exposure is managed in accordance with established policies that limit market risk and require daily reporting of potential financial exposure to senior management, including the chief risk officer. Because we generally manage physical gas assets and economically protect our positions by hedging in the futures markets, our open exposure is generally mitigated. We employ daily risk testing, using both VaR and stress testing, to evaluate the risks of our open positions.

Natural gas markets experienced levels of high volatility and increased prices due to the extended extreme cold weather during the first quarter of 2014, resulting in our VaR to be at elevated levels as compared to prior periods. We actively managed and monitored the open positions and exposures that were driving the elevated VaR levels not only to remain in compliance with established policies, but also to mitigate the operational risks of not being able to meet customer needs under these extreme conditions. As conditions moderated at the end of the first quarter, our period-end VaR was consistent with historical periods. We actively monitor open commodity positions and the resulting VaR. We also continue to maintain a relatively matched book, where our total buy volume is close to our sell volume, with minimal open natural gas price risk. Based on a 95% confidence interval and employing a 1-day holding period, we had the following VaRs.

	Three months ended September 30,		Nine months ended September 30,	
In millions	2014	2013	2014	2013
Period end	$7.2	$2.5	$7.2	$2.5
Average	3.1	2.3	4.1	2.0
High	8.0	3.1	19.7	3.1
Low	1.8	1.9	1.8	1.2

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 $0.9 billion of variable-rate debt outstanding at September 30, 2014, a 100 basis point change in market interest rates would have resulted in an increase in pre-tax interest expense of $9 million on an annualized basis.

We utilize interest rate swaps to help us achieve our desired mix of variable to fixed-rate debt. Our variable-rate debt target generally ranges from 20% to 45% of total debt. We also may use forward-starting interest rate swaps and interest rate lock agreements to lock in fixed interest rates on our forecasted issuances of debt. The objective of these hedges is to offset the variability of future payments associated with the interest rate on debt instruments we expect to issue. The gain or loss on the interest rate swaps designated as cash flow hedges is generally deferred in accumulated OCI until settlement, at which point it is amortized to interest expense over the period of the related hedge interest payments. For additional information, see Note 5 to our unaudited Condensed Consolidated Financial Statements included under Part 1, Item 1 herein.

Credit Risk

Wholesale Services We have established credit policies to determine and monitor the creditworthiness of counterparties, as well as the quality of pledged collateral. We also utilize master netting agreements whenever possible to mitigate exposure to counterparty credit risk. When we are engaged in more than one outstanding derivative transaction with the same counterparty and we also have a legally enforceable netting agreement with that counterparty, the "net" mark-to-market exposure represents the netting of the positive and negative exposures with that counterparty and a reasonable measure of our credit risk. We also use other netting agreements with certain counterparties with whom we conduct significant transactions. Master netting agreements enable us to net certain assets and liabilities by counterparty. We also net across product lines and against cash collateral, provided the master netting and cash collateral agreements include such provisions.

Additionally, we may require counterparties to pledge additional collateral when deemed necessary. We conduct credit evaluations and obtain appropriate internal approvals for a counterparty's line of credit before any transaction with the counterparty is executed. In most cases, the counterparty must have an investment grade rating, which includes a minimum long-term debt rating of Baa3 from Moody's and BBB- from S&P. Generally, we require credit enhancements by way of guaranty, cash deposit or letter of credit for transaction counterparties that do not have investment grade ratings.

We have a concentration of credit risk as measured by our 30-day receivable exposure plus forward exposure. As of September 30, 2014, our top 20 counterparties represented 50% of the total counterparty exposure of $360 million, derived by adding together the top 20 counterparties' exposures, exclusive of customer deposits, and dividing by the total of our counterparties' exposures.

As of September 30, 2014, our counterparties, or the counterparties' guarantors, had a weighted average S&P equivalent credit rating of A-, which is consistent with the prior year. The S&P equivalent credit rating is determined by a process of converting the lower of the S&P or Moody's ratings to an internal rating ranging from 9 to 1, with 9 being equivalent to AAA/Aaa by S&P and Moody's and 1 being D or Default by S&P and Moody's. A counterparty that does not have an external rating is assigned an internal rating based on the strength of the financial ratios of 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. The following table shows our third-party natural gas contracts receivable and payable positions.

	Gross receivables			Gross payables		
In millions	Sep. 30, 2014	Dec. 31, 2013	Sep. 30, 2013	Sep. 30, 2014	Dec. 31, 2013	Sep. 30, 2013
Netting agreements in place:						
Counterparty is investment grade	$308	$496	$310	$192	$265	$229
Counterparty is non-investment grade	6	-	-	8	10	7
Counterparty has no external rating	207	260	185	383	393	302
No netting agreements in place:						
Counterparty is investment grade	13	29	4	1	2	-
Counterparty has no external rating	10	1	3	28	1	1

Amount recorded on unaudited Condensed Consolidated Statements of Financial Position	$544	$786	$502	$612	$671	$539

We have 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, we would need to post collateral to continue transacting business with some of our counterparties. If such collateral were not posted, our 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 with our counterparties would have totaled $10 million at September 30, 2014, which would not have had a material impact on our consolidated results of operations, cash flows or financial condition.

There have been no significant changes to our credit risk related to any of our segments other than wholesale services, as described in Item 7A ”Quantitative and Qualitative Disclosures about Market Risk” of our 2013 Form 10-K.

ITEM 4. CONTROLS AND PROCEDURES.

(a) Evaluation of disclosure controls and procedures. Under the supervision of and with the participation of our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our disclosure controls and procedures, as such term is defined under Rule 13a-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the Exchange Act), as of September 30, 2014, the end of the period covered by this report. Based on their evaluation, our principal executive officer and our principal financial officer have concluded that our disclosure controls and procedures were not effective as of September 30, 2014 because of the material weakness in our internal control over financial reporting described below.

Material Weakness in Internal Control Over Financial Reporting

In connection with the preparation of our condensed consolidated financial statements included in this Quarterly Report on Form 10-Q, we concluded that there was a material weakness in our internal control over financial reporting. A material weakness is a deficiency, or combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the Company’s annual or interim financial statements will not be prevented or detected on a timely basis.

We did not maintain effective controls to appropriately apply the accounting guidance related to the recognition of allowed versus incurred costs. Specifically, the Company did not have controls to address the recognition of allowed versus incurred costs, primarily related to an allowed equity return, applied to the accounting for our regulated infrastructure programs and related disclosures that operated at a level of precision to prevent or detect potential material misstatements to the Company’s consolidated financial statements. This control deficiency could result in misstatements of the aforementioned accounts and disclosures that would result in a material misstatement of the consolidated financial statements that would not be prevented or detected. Accordingly, our management has concluded that the deficiency constitutes a material weakness.

As a result of the material weakness described above, the Company has revised its consolidated financial statements for the years ended December 31, 2013, 2012 and 2011, for each of the quarterly periods during the year ended December 31, 2013, and for the quarters ended March 31, 2014 and June 30, 2014. The Company has amended our Annual Report on Form 10-K for the year ended December 31, 2013 to reflect the revisions and the conclusion by our management that internal control over financial reporting and disclosure controls and procedures were not effective as of December 31, 2013.

Remediation Plan

We are committed to remediating the material weakness by implementing changes to our internal control over financial reporting. We have already implemented additional procedures to address the underlying causes of the material weakness prior to filing this quarterly report on Form 10-Q, and we will continue to implement changes and improvements in the internal control over financial reporting to remediate the control deficiency that caused the material weakness. The following actions have been, are being, or are planned to be implemented:

- Reviewed all existing regulatory programs to ensure the proper evaluation of deferral components and proper treatment of allowed versus incurred costs pursuant to the accounting guidance. This review was completed prior to the issuance of revised consolidated financial statements.
- Complete training for all appropriate personnel regarding the applicable accounting guidance and requirements through meetings concurrent with the process to evaluate all infrastructure and other regulated programs.
-

Create a process and design controls to capture and calculate allowed versus incurred costs and to record appropriate amounts in the consolidated financial statements. The Company will identify appropriate processes, reviews and other controls to ensure accurate amounts are appropriately reflected in the Company's consolidated financial statements.

- The Company is also considering other improvements and enhancements, including a review of organization structure, reporting relationships and adequacy of staffing levels, among others.

Management is committed to a strong internal control environment and believes that, when fully implemented and tested, the actions described above will remediate the material weakness in our internal control over financial reporting. We will continue to assess the effectiveness of our remediation efforts with our future assessments of the effectiveness of internal control over financial reporting. As we continue to evaluate and work to improve our internal control over financial reporting, management may determine to take additional measures to address the material weakness or determine to modify the remediation plan described above. Until the remediation steps set forth above are fully implemented, the material weakness described above will continue to exist.

(b) Changes in Internal Control over Financial Reporting. There were no changes in our internal control over financial reporting that occurred during the quarter ended September 30, 2014, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II - OTHER INFORMATION

Item 1. Legal Proceedings.

The nature of our business ordinarily results in periodic regulatory proceedings before various state and federal authorities. In addition, we are party, as both plaintiff and defendant, to a number of lawsuits related to our business on an ongoing basis. Management believes that the outcome of all regulatory proceedings and litigation in which we are currently involved will not have a material adverse effect on our consolidated financial condition. For more information, see Note 10 to our unaudited Condensed Consolidated Financial Statements in this quarterly filing under the caption “Litigation.”

In the third quarter of 2013, we commenced an investigation into payments to local officials and related persons at one of the foreign ports serviced by Tropical Shipping. In October 2013, we voluntarily disclosed these matters to the U.S. Department of Justice (DOJ) and the SEC and have periodically reported our progress. We have completed our investigation and reported our findings to the DOJ and SEC. Both the DOJ and SEC have confirmed that they do not intend to pursue this matter further.

Item 1A. Risk Factors.

For information regarding our risk factors, see the factors discussed in Part I, Item 1A. Risk Factors in our Original Filing. These risk factors could materially affect our business, financial condition or future results. There have been no significant changes to our risk factors included in Item 1A of our Original Filing. The risks described in the referenced document are not the only risks facing the company. Additional risks and uncertainties not currently known to us or that we currently do not recognize as material also may materially adversely affect our business, financial condition or future results.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds.

There were no purchases of our common stock by us or any affiliated purchasers during the third quarter of 2014, and no unregistered sales of equity securities were made during this period.

Item 6. Exhibits.

Exhibit Number	Description of Exhibit	Filer	The Filings Referenced for Incorporation by Reference
2	Stock Purchase Agreement by and among Aqua Acquisition Corp., Ottawa Acquisition LLC and Birdsall, Inc.(1)	AGL Resources	Filed herewith
12	Statement of Computation of Ratio of Earnings to Fixed Charges	AGL Resources	Filed herewith
31.1	Certification of John W. Somerhalder II	AGL Resources	Filed herewith
31.2	Certification of Andrew W. Evans	AGL Resources	Filed herewith
32.1	Certification of John W. Somerhalder II	AGL Resources	Filed herewith
32.2	Certification of Andrew W. Evans		Filed herewith

		AGL Resources	
101.INS	XBRL Instance Document	AGL Resources	Filed herewith
101.SCH	XBRL Taxonomy Extension Schema	AGL Resources	Filed herewith
101.CAL	XBRL Taxonomy Extension Calculation Linkbase	AGL Resources	Filed herewith
101.DEF	XBRL Taxonomy Definition Linkbase	AGL Resources	Filed herewith
101.LAB	XBRL Taxonomy Extension Labels Linkbase	AGL Resources	Filed herewith
101.PRE	XBRL Taxonomy Extension Presentation Linkbase	AGL Resources	Filed herewith

(1) Portions of this exhibit have been omitted pursuant to a request for confidential treatment with the SEC. The omitted portions have been separately filed with the SEC. This exhibit replaces and supercedes in its entirety the Stock Purchase Agreement filed on July 30, 2014 with our Form 10-Q for the quarter ended June 30, 2014.

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: November 7, 2014 /s/ Andrew W. Evans
Executive Vice President and Chief Financial Officer