AGL RESOURCES INC
Form 10-Q
October 30, 2013

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

FORM 10-Q

(Mark One)

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

For the Quarterly Period Ended September 30, 2013

OR

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

For the transition period from to

Commission File Number 1-14174

AGL RESOURCES INC.
(Exact name of registrant as specified in its charter)

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

Ten Peachtree Place NE, Atlanta, Georgia 30309
(Address and zip code of principal executive offices)

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer,”

”accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.

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

Indicate by check mark whether the registrant is a shell company (as defined in Exchange Act Rule 12b-2). Yes ¨ No þ

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

Class	Outstanding as of October 23, 2013
Common Stock, $5.00 Par Value	118,788,590

AGL RESOURCES INC.
Quarterly Report on Form 10-Q
For the Quarter Ended September 30, 2013

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Glossary of Key Terms

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GLOSSARY OF KEY TERMS

2012 Form 10-K	Our Annual Report on Form 10-K for the year ended December 31, 2012, filed with the SEC on February 6, 2013
AGL Capital	AGL Capital Corporation
AGL Credit Facility	$1.3 billion credit agreement entered into by AGL Capital to support the AGL Capital commercial paper program
Atlanta Gas Light	Atlanta Gas Light Company
Bcf	Billion cubic feet
Central Valley	Central Valley Gas Storage, LLC
Chattanooga Gas	Chattanooga Gas Company
Compass Energy	Compass Energy Services, Inc.
EBIT	Earnings before interest and taxes, a non-GAAP measure that includes operating income and other income and excludes financing costs, including interest on debt, and income tax expense, each of which we evaluate on a consolidated level.
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 Storage	Golden Triangle Storage, Inc.
Heating Degree Days	A measure of the effects of weather on our businesses, calculated as the extent to which the average daily temperature is 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
LIFO	Last-in, first-out
LOCOM	Lower of weighted average cost or current market price
Marketers	Marketers selling retail natural gas in Georgia and certificated by the Georgia Commission
Moody’s	Moody’s Investors Service
New Jersey BPU	New Jersey Board of Public Utilities, the state regulatory agency for Elizabethtown Gas
Nicor	Nicor Inc. - an acquisition completed in December 2011 and former holding company of Nicor Gas
Nicor Advanced Energy	Prairie Point Energy, LLC, doing business as Nicor Advanced Energy
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
Nicor Services	Nicor Energy Services Company
Nicor Solutions	Nicor Solutions, LLC
NUI	NUI Corporation - an acquisition completed in November 2004
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, that excludes operation and maintenance expense, depreciation and amortization, certain taxes other than income taxes, Nicor merger expenses and gains or losses on the sale of our assets, if any.
OTC	Over-the-counter

PBR	Performance-based rate, a regulatory plan at Nicor Gas that provided economic incentives based on natural gas cost performance. The plan terminated in 2003.
Piedmont	Piedmont Natural Gas Company, Inc.
PP&E	Property, plant and equipment
S&P	Standard & Poor's Ratings Services
SEC	Securities and Exchange Commission
Sequent	Sequent Energy Management, L.P.
Seven Seas	Seven Seas Insurance Company, Inc.
SouthStar	SouthStar Energy Services, LLC
STRIDE	Atlanta Gas Light's Strategic Infrastructure Development and Enhancement program
Tennessee Authority	Tennessee Regulatory Authority, the state regulatory agency for Chattanooga Gas
TEU	Twenty-foot equivalent unit, a measure of volume in containerized shipping equal to one 20-foot-long container
Triton	Triton Container Investments, LLC
Tropical Shipping	Tropical Shipping and Construction Company Limited
VaR	Value at risk
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

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

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

In millions, except share amounts	As of September 30, 2013	December 31, 2012	September 30, 2012
Current assets			
Cash and cash equivalents	$ 131	$ 131	$ 91
Short-term investments	42	58	60
Receivables			
Energy marketing receivables	502	677	397
Gas, unbilled and other receivables	341	686	305
Less allowance for uncollectible accounts	32	28	31
Total receivables	811	1,335	671
Inventories, net	797	708	778
Regulatory assets	133	145	158
Derivative instruments	97	130	144
Other current assets	80	161	233
Total current assets	2,091	2,668	2,135
Long-term assets and other deferred debits			
Property, plant and equipment	10,920	10,478	10,281
Less accumulated depreciation	2,307	2,131	2,069
Property, plant and equipment, net	8,613	8,347	8,212
Goodwill	1,883	1,837	1,817
Regulatory assets	871	944	994
Intangible assets	180	96	96
Derivative instruments	15	14	15
Other long-term assets and deferred debits	251	235	234
Total long-term assets and other deferred debits	11,813	11,473	11,368
Total assets	$ 13,904	$ 14,141	$ 13,503
Current liabilities			
Short-term debt	$ 832	$ 1,377	$ 1,048
Energy marketing trade payable	539	611	444
Accounts payable - trade	304	334	292
Regulatory liabilities	174	161	117
Accrued expenses	157	140	119
Customer deposits and credit balances	140	143	159

Accrued environmental remediation liabilities	48	57	61
Derivative instruments	38	33	37
Accrued regulatory infrastructure program costs	32	121	122
Current portion of long-term debt and capital leases	-	226	226
Other current liabilities	143	135	139
Total current liabilities	2,407	3,338	2,764
Long-term liabilities and other deferred credits			
Long-term debt	3,816	3,327	3,330
Accumulated deferred income taxes	1,587	1,588	1,555
Regulatory liabilities	1,524	1,477	1,465
Accrued environmental remediation liabilities	416	387	365
Accrued retiree welfare benefits	262	268	296
Accrued pension obligations	249	240	213
Derivative instruments	6	6	5
Other long-term liabilities and other deferred credits	74	75	112
Total long-term liabilities and other deferred credits	7,934	7,368	7,341
Total liabilities and other deferred credits	10,341	10,706	10,105
Commitments, guarantees and contingencies (see Note 9)			
Equity			
Common stock, $5 par value; 750,000,000 shares authorized: outstanding: 118,778,298 shares at September 30, 2013, 117,855,075 shares at December 31, 2012 and 117,743,809 shares at September 30, 2012	595	590	590
Additional paid in capital	2,046	2,014	2,012
Retained earnings	1,100	1,035	990
Accumulated other comprehensive loss	(208)	(218)	(203)
Treasury shares, at cost: 216,523 shares at September 30, 2013 and December 31, 2012 and September 30, 2012	(8)	(8)	(8)
Total common shareholders' equity	3,525	3,413	3,381
Noncontrolling interest	38	22	17
Total equity	3,563	3,435	3,398
Total liabilities and equity	$ 13,904	$ 14,141	$ 13,503

See Notes to Condensed Consolidated Financial Statements (Unaudited).

Glossary of Key Terms

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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	2013	2012	2013	2012
Operating revenues (includes revenue taxes of $8 and $82 for the three and nine months in 2013 and $8 and $63 for the three and nine months in 2012)	$ 675	$ 614	$ 3,288	$ 2,704
Operating expenses				
Cost of goods sold	229	215	1,609	1,174
Operation and maintenance	226	212	718	675
Depreciation and amortization	109	104	325	310
Taxes other than income taxes	29	27	144	123
Nicor merger expenses	-	2	-	15
Total operating expenses	593	560	2,796	2,297
Gain on sale of Compass Energy	-	-	11	-
Operating income	82	54	503	407
Other income	7	6	19	19
Interest expense, net	(43)	(45)	(135)	(137)
Earnings before income taxes	46	15	387	289
Income tax expense	18	6	145	106
Net income	28	9	242	183
Less net income attributable to the noncontrolling interest	-	-	11	10
Net income attributable to AGL Resources Inc.	$ 28	$ 9	$ 231	$ 173
Per common share data				
Basic earnings per common share attributable to AGL Resources Inc. common shareholders	$ 0.24	$ 0.08	$ 1.96	$ 1.48
Diluted earnings per common share attributable to AGL Resources Inc. common shareholders	$ 0.24	$ 0.08	$ 1.96	$ 1.48
Cash dividends declared per common share	$ 0.47	$ 0.46	$ 1.41	$ 1.28
Weighted average number of common shares outstanding				
Basic	118.2	117.1	117.8	116.9
Diluted	118.5	117.5	118.1	117.3

See Notes to Condensed Consolidated Financial Statements (Unaudited).

Glossary of Key Terms

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

In millions	Three months ended September 30, 2013	2012	Nine months ended September 30, 2013	2012
Net income	$ 28	$ 9	$ 242	$ 183
Other comprehensive income (loss), net of tax				
Retirement benefit plans				
Reclassification of actuarial losses to net benefit cost (net of income tax of $3 and $8 for the three and nine months ended September 30, 2013, and $2 and $6 for the three and nine months ended September 30, 2012)	3	2	11	10
Reclassification of prior service credits to net benefit cost (net of income tax of $(1) for the nine months ended September 30, 2013)	(2)	-	(3)	-
Retirement benefit plans	1	2	8	10
Cash flow hedges, net of tax				
Reclassification of realized derivative instrument (gains) losses to net income (net of income tax of $1 for the nine months ended September 30, 2013 and $1 and $2 for the three and nine months ended September 30, 2012)	-	2	2	4
Cash flow hedges, net	-	2	2	4
Other comprehensive income, net of tax	1	4	10	14
Comprehensive income	29	13	252	197
Less comprehensive income attributable to noncontrolling interest	-	-	11	10
Comprehensive income attributable to AGL Resources Inc.	$ 29	$ 13	$ 241	$ 187

See Notes to Condensed Consolidated Financial Statements (Unaudited).

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

	AGL Resources Inc. Shareholders							
	Common stock		Additional paid-in	Retained	Accumulated other comprehensive	Treasury	Noncontrolling	
In millions, except per share amounts	Shares	Amount	capital	earnings	loss	shares	interest	Total
Balance as of December 31, 2011	117.0	$ 586	$ 1,989	$ 967	$ (217)	$ (7)	$ 21	$ 3,339
Net income	-	-	-	173	-	-	10	183
Other comprehensive income	-	-	-	-	14	-	-	14
Dividends on common stock ($1.28 per share)	-	-	-	(150)	-	-	-	(150)
Distributions to noncontrolling interest	-	-	-	-	-	-	(14)	(14)
Stock granted, share-based compensation, net of forfeitures	-	-	(9)	-	-	-	-	(9)
Stock issued, dividend reinvestment plan	0.2	1	7	-	-	-	-	8
Stock issued, share-based compensation, net of forfeitures	0.5	3	17	-	-	(1)	-	19
Stock-based compensation expense (net of tax)	-	-	8	-	-	-	-	8
Balance as of September 30, 2012	117.7	$ 590	$ 2,012	$ 990	$ (203)	$ (8)	$ 17	$ 3,398

	AGL Resources Inc. Shareholders							
	Common stock		Additional paid-in	Retained	Accumulated other comprehensive	Treasury	Noncontrolling	
In millions, except per share amounts	Shares	Amount	capital	earnings	loss	shares	interest	Total
	117.9	$ 590	$ 2,014	$ 1,035	$ (218)	$ (8)	$ 22	$ 3,435

Balance as of December 31, 2012								
Net income	-	-	-	231	-	-	11	242
Other comprehensive income	-	-	-	-	10	-	-	10
Dividends on common stock ($1.41 per share)	-	-	-	(166)	-	-	-	(166)
Contribution from noncontrolling interest							22	22
Distributions to noncontrolling interest	-	-	-	-	-	-	(17)	(17)
Stock granted, share-based compensation, net of forfeitures	-	-	(6)		-	-	-	(6)
Stock issued, dividend reinvestment plans	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	$ 2,046	$ 1,100	$ (208)	$ (8)	$ 38	$ 3,563

See Notes to Condensed Consolidated Financial Statements (Unaudited).

Glossary of Key Terms

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

In millions	Nine months ended September 30, 2013	2012
Cash flows from operating activities		
Net income	$ 242	$ 183
Adjustments to reconcile net income to net cash flow provided by operating activities		
Depreciation and amortization	325	310
Change in derivative instrument assets and liabilities	37	61
Deferred income taxes	(28)	89
Gain on sale of Compass Energy	(11)	-
Changes in certain assets and liabilities		
Receivables, other than energy marketing	354	403
Energy marketing receivables and trade payables, net	103	64
Prepaid taxes	64	13
Accrued expenses	17	(43)
Accrued natural gas costs	14	(4)
Inventories	(89)	(28)
Trade payables, other than energy marketing	(19)	14
Other, net	61	(30)
Net cash flow provided by operating activities	1,070	1,032
Cash flows from investing activities		
Expenditures for property, plant and equipment	(535)	(569)
Acquisitions of assets	(154)	-
Disposition of assets	12	-
Other, net	16	(8)
Net cash flow used in investing activities	(661)	(577)
Cash flows from financing activities		
Issuance of senior notes	494	-
Contribution from noncontrolling interest	22	-
Net payments and borrowings of short-term debt	(545)	(273)
Payment of senior notes	(225)	-
Dividends paid on common shares	(166)	(150)
Distribution to noncontrolling interest	(17)	(14)
Payment of medium-term notes	-	(15)
Proceeds from termination of interest rate swap	-	17
Other, net	28	2
Net cash flow used in financing activities	(409)	(433)
Net increase in cash and cash equivalents	-	22
Cash and cash equivalents at beginning of period	131	69
Cash and cash equivalents at end of period	$ 131	$ 91
Cash paid during the period for		
Interest	$ 138	$ 142

Income taxes	$ 90	$ 4
Non cash financing transaction		
Refinancing of gas facility revenue bonds	$ 200	$ -

See Notes to Condensed Consolidated Financial Statements (Unaudited).

Glossary of Key Terms

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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 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, 2012 Condensed Consolidated Statement of Financial Position data was derived from our audited financial statements, but does not include all disclosures required by GAAP. We have prepared the accompanying unaudited Condensed Consolidated Financial Statements under the rules 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 2012 Form 10-K.

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 and 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 and 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 8 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. Certain amounts from prior periods have been reclassified and revised to conform to the current period presentation. Such reclassifications and revisions had no material impact on prior periods.

During the three months ended September 30, 2013, we recorded a $4 million ($2 million net of tax) reduction to our interest expense to correct the amortization period of credit fees related to the execution of the AGL Credit Facility in 2010 and subsequent amendment in 2011.

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 2012 Form 10-K. There were no significant changes to our accounting policies during the nine months ended September 30, 2013.

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 regulatory infrastructure program accruals, environmental remediation accruals, 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, Cash Equivalents and Cash Investments

Our cash and cash equivalents consist primarily of cash on deposit, money market accounts and certificates of deposit held by domestic subsidiaries with original maturities of three months or less. As of September 30, 2013 and 2012, and December 31, 2012, we had $74 million, $76 million and $80 million, respectively, of cash and short-term investments held by Tropical Shipping. This cash and investments are available for use by our other operations only if we repatriate a portion of Tropical Shipping’s earnings in the form of a dividend, and pay a significant amount of United States income tax. See Note 12 to our Consolidated Financial Statements included in Item 8 of our 2012 Form 10-K for additional information on our income taxes.

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Inventories

For our regulated utilities, except Nicor Gas, our gas inventories and the inventories we hold for Marketers in Georgia are carried at cost on a WACOG 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 9 for information regarding a regulatory filing by Atlanta Gas Light related to gas inventory.

Nicor Gas' inventory is carried at cost on a LIFO basis. Inventory decrements occurring during interim periods that are expected to be restored prior to year-end are charged to cost of goods sold at the estimated annual replacement cost, and the difference between this cost and the actual liquidated LIFO layer cost is recorded as a temporary LIFO inventory liquidation. Any temporary LIFO liquidation is included as a current liability in our unaudited Condensed Consolidated Statements of Financial Position. Interim inventory decrements that are not expected to be restored prior to year-end are charged to cost of goods sold at the actual LIFO cost of the layers liquidated. As of September 30, 2013 and 2012, there was no inventory decrement.

Our retail operations, wholesale services and midstream operations segments are carried at the lower of cost on a WACOG basis or market value. 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 periods presented, we recorded LOCOM adjustments to cost of goods sold in the following amounts to reduce the value of our inventories to market value.

	Three months ended September 30,		Nine months ended September 30,	
In millions	2013	2012	2013	2012
Retail operations	$ 1	$ -	$ 1	$ 3
Wholesale services	-	-	8	18
Midstream operations	-	-	-	1

Energy Marketing Receivables and Payables

Our wholesale services segment provides services to retail and wholesale marketers and utility and industrial customers. These customers, also known as counterparties, utilize netting agreements, which enable our wholesale services segment to net receivables and payables by counterparty. Wholesale services also nets across product lines and against cash collateral, provided the master netting and cash collateral agreements include such provisions. 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, 2013, December 31, 2012 and September 30, 2012, 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 position. If such collateral were not posted, wholesale services' ability to continue transacting business with these counterparties would be negatively 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 2012 Form 10-K.

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.

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Derivative Instruments

The fair value of the natural gas derivative instruments that we use to manage exposures arising from changing natural gas prices 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 3 and Note 4 for additional derivative disclosures.

Distribution Operations Nicor Gas, subject to review by the Illinois Commission, and Elizabethtown Gas, in accordance with a directive from the New Jersey BPU, enter into derivative instruments to hedge the impact of market fluctuations in natural gas prices. In accordance with regulatory requirements, any realized gains and losses related to these derivatives are reflected in natural gas costs and ultimately included in billings to customers. Such derivative instruments are reported at fair value at the end of each reporting period. Hedge accounting is not elected and, in accordance with accounting guidance pertaining to rate-regulated entities, unrealized changes in the fair value of these derivative instruments are deferred or accrued as regulatory assets or liabilities until the related revenue is recognized.

On June 28, 2013 we entered into an OTC weather derivative to reduce the risk of lower operating margins related to the risk of significantly warmer-than-normal weather in Illinois during the fourth quarter of 2013. The weather derivative is based on fourth quarter 2013 Heating Degree Days at Chicago Midway International Airport and is a cash-settled option. If weather is warmer than normal during the fourth quarter of 2013 the option would partially offset lower operating margin that would result from lower customer usage. Since the option would not be exercised if heating degree days are equal to or higher than normal, the option would not offset margins that are higher because of colder than normal weather.

Nicor Gas also enters into derivative instruments to reduce the earnings volatility of certain forecasted operating costs arising from fluctuations in natural gas prices, such as the purchase of natural gas for company use. These derivative instruments are carried at fair value. To the extent hedge accounting is not elected, changes in such fair values are recorded in the current period as operation and maintenance expenses.

Retail Operations We have designated a portion of our derivative instruments, consisting of financial swaps to manage the risk associated with forecasted natural gas purchases and sales, as cash flow hedges. We record derivative gains or losses arising from cash flow hedges in OCI and reclassify them into earnings in the same period that the underlying hedged item is recognized in earnings.

We currently have minimal hedge ineffectiveness, defined as when the gains or losses on the hedging instrument more than offset the losses or gains on the hedged item. Any cash flow hedge ineffectiveness is recorded in cost of goods sold in the period in which it occurs. We have not designated the remainder of our derivative instruments as hedges for accounting purposes, and we record changes in the fair value of such instruments within cost of goods sold in the period of change.

We also enter into weather derivative contracts as economic hedges of operating margins in the event of warmer-than-normal weather in the Heating Season. Exchange-traded options are carried at fair value, with changes reflected in operating revenues. Non exchange-traded options are accounted for using the intrinsic value method and do not qualify for hedge accounting designation. Changes in the intrinsic value for non exchange-traded contracts are also reflected in operating revenues in our unaudited Condensed Consolidated Statements of Income.

Wholesale Services We purchase natural gas for storage when the current market price we pay to buy and transport natural gas plus the cost to store and finance the natural gas is less than the market price we can receive in the future, resulting in a positive net operating margin. We use NYMEX futures and OTC contracts to sell natural gas at that future price to substantially lock in the operating margin we ultimately will realize when the stored natural gas is sold.

We also enter into transactions to secure transportation capacity between delivery points in order to serve our customers and various markets. We use NYMEX futures and OTC contracts to capture the price differential or spread between the locations served by the capacity in order to substantially lock in the operating margin we will ultimately realize when we physically flow natural gas between delivery points. These contracts generally meet the definition of derivatives and are carried at fair value, with changes in fair value recorded in operating revenues in the period of change. These contracts are not designated as hedges for accounting purposes.

The purchase, transportation, storage and sale of natural gas are accounted for on a weighted average cost or accrual basis, as appropriate, rather than on the fair value basis we utilize for the derivatives used to mitigate the natural gas price risk associated with our storage and transportation portfolio. We incur monthly demand charges for the contracted storage and transportation capacity, and payments associated with asset management agreements, and recognize these demand charges and payments in the period they are incurred. This difference in accounting can result in volatility in our reported earnings, even though the economic margin is essentially unchanged from the dates the transactions were consummated.

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Depreciation Expense

We compute depreciation expense for distribution operations by applying composite, straight-line rates (approved by the state regulatory agencies) to the investment in depreciable property.

On August 30, 2013 Nicor Gas filed a depreciation study with the Illinois Commission that proposed a composite depreciation rate of 3.07% compared to the current composite rate of 4.10%. On October 23, 2013 the Illinois Commission approved our proposed composite depreciation rate for Nicor Gas. The depreciation rate is effective as of the date the depreciation study was filed and a $4 million reduction to our depreciation expense will be recognized in the fourth quarter of 2013 for the period from August 30, 2013 through September 30, 2013.

Goodwill

Our annual goodwill impairment analysis that was performed during the fourth quarter of 2012 indicated that the estimated fair value of a reporting unit within our midstream operations segment, with $14 million of goodwill, exceeded its carrying value by less than 10% as of our testing date. During the third quarter of 2013 we identified a reduction in the near-term market rates at which we are able to re-contract capacity at our storage facilities. We considered a decline in near-term rates an indicator of potential impairment and, accordingly, conducted an interim goodwill impairment analysis during the third quarter of 2013.

The fair value of this reporting unit was determined utilizing the income and market approaches. The market approach is based on observable transactions of comparable companies and assets. The income approach estimates fair value based upon the present value of estimated future cash flows discounted at an appropriate risk-free rate. These forecasts contain a degree of uncertainty, and changes in the projected cash flows could significantly increase or decrease the estimated fair value of the reporting unit. Key assumptions used in the income approach included long-term growth rates used to determine the terminal value at the end of the discrete forecast period, current and future rates charged for contracted capacity and a discount rate. The discount rate is applied to estimated future cash flows and is one of the most significant assumptions used to determine fair value under the income approach. As interest rates rise, the calculated fair values will decrease. The terminal growth rate was based on a combination of historical and forecasted statistics for real gross domestic product and personal income. The rates we charge to customers for capacity in the storage caverns are based on internal and external rates forecasts.

While near-term rates have declined, management’s forecast for long-term rates have not significantly changed since our 2012 annual impairment analysis was completed. Our interim goodwill impairment test indicated that the estimated fair value of this reporting unit continues to exceed its carrying value. We continue to monitor this reporting unit for impairment and note that continued declines in capacity or subscription rates or for a sustained period at the current market rates may result in an impairment of goodwill. The risk of impairment of the underlying long-lived assets is not estimated to be significant because the assets have long remaining useful lives and authoritative accounting guidance requires such assets to be tested for impairment based on the basis of undiscounted cash flows over their remaining useful lives.

Regulatory Assets and Liabilities

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 otherwise would 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. We are not aware of any evidence that these costs will not be recoverable through either rate riders or base rates, and we believe that we will be able to recover such costs consistent with our historical recoveries. In the event that the provisions of authoritative guidance related to regulated operations were no longer applicable, we would recognize a write-off of regulatory assets that would result in a charge to net income and be classified as an extraordinary item.

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Our regulatory assets and liabilities are summarized in the following table.

In millions	September 30, 2013	December 31, 2012	September 30, 2012
Regulatory assets			
Recoverable regulatory infrastructure program costs	$ 46	$ 47	$ 46
Recoverable environmental remediation costs	30	38	33
Recoverable pension and retiree welfare benefit costs	19	19	27
Other regulatory assets	38	41	52
Total regulatory assets - current	133	145	158
Recoverable environmental remediation costs	456	438	421
Recoverable pension and retiree welfare benefit costs	183	196	228
Recoverable regulatory infrastructure program costs	104	167	194
Long-term debt fair value adjustment	84	90	92
Other regulatory assets	44	53	59
Total regulatory assets - long-term	871	944	994
Total regulatory assets	$ 1,004	$ 1,089	$ 1,152
Regulatory liabilities			
Accrued natural gas costs	$ 104	$ 93	$ 62
Bad debt rider	37	37	30
Accumulated removal costs	17	16	14
Other regulatory liabilities	16	15	11
Total regulatory liabilities - current	174	161	117
Accumulated removal costs	1,448	1,393	1,381
Unamortized investment tax credit	26	29	30
Regulatory income tax liability	26	27	23
Bad debt rider	20	17	16
Other regulatory liabilities	4	11	15
Total regulatory liabilities - long-term	1,524	1,477	1,465
Total regulatory liabilities	$ 1,698	$ 1,638	$ 1,582

There have been no significant new types of regulatory assets or liabilities beyond those discussed in Note 2 to our Consolidated Financial Statements and related notes in Item 8 of our 2012 Form 10-K.

Other Income

Our other income is detailed in the following table for the periods presented.

	Three months ended September 30,		Nine months ended September 30,	
In millions	2013	2012	2013	2012
Allowance for funds used during construction (AFUDC) - equity	$ 3	$ 2	$ 9	$ 4
Equity investment income (1)	3	2	8	10

Other, net		1		2		2		5
Total other income	$	7	$	6	$	19	$	19

(1) Primarily relates to our investment in Triton. See Note 8 for additional information.

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 could occur 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. The vesting of certain shares of the restricted stock and restricted stock units depends on the satisfaction of defined performance 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.

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The following table shows the calculation of our diluted shares attributable to AGL Resources Inc. common shareholders for the periods presented, if performance units currently earned under the plan ultimately vest and 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)	2013	2012	2013	2012
Net income attributable to AGL Resources Inc.	$ 28	$ 9	$ 231	$ 173
Denominator:				
Basic weighted average number of shares outstanding (1)	118.2	117.1	117.8	116.9
Effect of dilutive securities	0.3	0.4	0.3	0.4
Diluted weighted average number of shares outstanding	118.5	117.5	118.1	117.3
Earnings per share:				
Basic	$ 0.24	$ 0.08	$ 1.96	$ 1.48
Diluted	$ 0.24	$ 0.08	$ 1.96	$ 1.48

(1) Daily weighted average shares outstanding.

Acquisitions

On January 31, 2013 our retail operations segment acquired approximately 500,000 service plans and certain other assets from NiSource Inc. for $120 million, plus $2 million of working capital. These service plans provide home warranty protection solutions and energy efficiency leasing solutions for residential and small business utility customers and complement the retail services business acquired in the Nicor merger. The preliminary allocation of the purchase price is as follows:

In millions	
Current assets	$ 5
PP&E	11
Goodwill	46
Intangible assets	64
Current liabilities	(4)
Total purchase price	$ 122

Intangible assets related to this acquisition are primarily customer relationships of $47 million and trade names of $17 million. The amortization periods are estimated to be 14 years for customer relationships and 10 years for trade names.

On June 30, 2013 our retail operations segment acquired approximately 33,000 residential and commercial energy customer relationships in Illinois for $32 million. These customer relationships have been recorded as an intangible asset and are expected to be amortized on a straight-line basis over an estimated period of 14 to 16 years.

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). Under the terms of the purchase and sale agreement, we are eligible to receive contingent cash consideration up to $8 million with a guaranteed minimum receipt of $3 million. The contingent cash consideration will be received from the buyer over a five-year earn out period based upon the financial performance of Compass Energy.

Accounting Developments

On January 1, 2013 we adopted ASU 2011-11, Disclosures about Offsetting Assets and Liabilities and ASU 2013-01, Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities, which require disclosures about offsetting and related arrangements in order to help financial statement users better understand the effect of those arrangements on our financial position. This guidance had no impact on our unaudited Condensed Consolidated Financial Statements. See Note 4 for additional disclosures about our offsetting of derivative assets and liabilities.

On January 1, 2013 we adopted ASU 2013-02, Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income, which requires enhanced disclosures of amounts reclassified out of accumulated other comprehensive income by component. This guidance had no impact on our unaudited Condensed Consolidated Financial Statements. See Note 7 for additional disclosures relating to accumulated other comprehensive income.

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Note 3 - 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 Consolidated Statements of Financial Position as of the dates presented. See Note 4 for additional derivative instrument information.

	Recurring fair values - Derivative instruments					
	September 30, 2013		December 31, 2012		September 30, 2012	
In millions	Assets (1)	Liabilities	Assets (1)	Liabilities	Assets (1)	Liabilities
Natural gas derivatives						
Quoted prices in active markets (Level 1)	$ 4	$ (52)	$ 8	$ (45)	$ 11	$ (55)
Significant other observable inputs (Level 2)	60	(41)	96	(30)	100	(33)
Netting of cash collateral	45	49	33	36	47	46
Total carrying value (2) (3)	$ 109	$ (44)	$ 137	$ (39)	$ 158	$ (42)
Interest rate derivatives						
Significant other observable inputs (Level 2)	$ -	$ -	$ 3	$ -	$ -	$ -

(1) Balances of $3 million of premium at September 30, 2013, $4 million at December 31, 2012 and $1 million at September 30, 2012 associated with weather derivatives have been excluded, as they are not material and some are accounted for based on intrinsic value.

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

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

Money Market Funds

The fair values of our money market funds were recorded within short-term investments as follows:

In millions	At September 30, 2013	At December 31, 2012	At September 30, 2012
Money market funds (1)	$ 48	$ 66	$ 69

(1) Carried at fair value and classified as Level 1 within the fair value hierarchy.

Debt

Our long-term debt is recorded at amortized cost, with the exception of Nicor Gas' first mortgage bonds, which were 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. We estimate the fair value of our debt using a discounted cash flow technique that incorporates a market interest yield curve with adjustments for duration, optionality and risk profile. The following table presents the amortized cost and fair value of our long-term debt as of the following dates.

In millions	September 30, 2013	December 31, 2012	September 30, 2012
Long-term debt amortized cost	$ 3,816	$ 3,553	$ 3,556
Long-term debt fair value (1)	4,024	4,057	4,100

(1) Fair value determined using Level 2 inputs.

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Note 4 - 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. See Note 3 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, 2013, for agreements with such features, derivative instruments with liability fair values totaled $44 million, for which we had posted no collateral to our counterparties. In addition, our energy marketing receivables and payables, which also have credit-risk-related or other contingent features, are discussed in Note 2. Our derivative instrument activities are included within operating cash flows as an adjustment to net income of $37 million and $61 million for the nine months ended September 30, 2013 and 2012, respectively. See Note 3 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	Income Statement
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 Changes in fair value of the hedged item are recorded as adjustments to the carrying amount of the hedged item	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
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

Distribution Operations

The following amounts represent net realized gains (losses) related to hedging natural gas costs for the periods presented.

In millions	Three months ended September 30, 2013	Three months ended September 30, 2012	Nine months ended September 30, 2013	Nine months ended September 30, 2012
Nicor Gas	$ (6)	$ (12)	$ 2	$ (60)
Elizabethtown Gas	(1)	(6)	(5)	(23)

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, 2013 (2)	December 31, 2012	September 30, 2012
Hedge designation			
Cash flow hedges	3	6	7
Not designated as hedges	40	96	35
Total hedges	43	102	42
Hedge position			
Short position	(2,788)	(1,955)	(1,994)
Long position	2,831	2,057	2,036
Net long position	43	102	42

(1) Volumes related to Nicor Gas exclude variable-priced contracts, which are accounted for as derivatives, but whose fair values are not directly impacted by changes in commodity prices.
(2) Approximately 97% of these contracts have durations of two years or less and the remaining 3% expire between 2 and 6 years.

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Derivative Instruments in our Unaudited Condensed Consolidated Statements of Financial Position

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.

	Classification	September 30, 2013		December 31, 2012		September 30, 2012		December 31, 2011	
In millions	(1) (2)	Assets	Liabilities	Assets	Liabilities	Assets	Liabilities	Assets	Liabilities
Designated as cash flow hedges and fair value hedges									
Natural gas contracts	Current	$6	$(5)	$1	$(2)	$4	$(3)	$9	$(12)
Natural gas contracts	Long-term	-	-	3	-	-	-	-	-
Interest rate swap agreements	Long-term	-	-	-	-	-	-	13	(13)
Total		6	(5)	4	(2)	4	(3)	22	(25)
Not designated as cash flow hedges									
Natural gas contracts	Current	445	(462)	394	(355)	427	(408)	706	(689)
Natural gas contracts	Long-term	143	(153)	45	(50)	54	(50)	133	(116)
Total		588	(615)	439	(405)	481	(458)	839	(805)
Gross amount of recognized assets and liabilities		594	(620)	443	(407)	485	(461)	861	(830)
Gross amounts offset in our unaudited Condensed Consolidated Statements of Financial Position		(482)	576	(299)	368	(326)	419	(573)	720
Net amounts of assets and liabilities presented in our unaudited Condensed Consolidated Statements of Financial Position		$112	$(44)	$144	$(39)	$159	$(42)	$288	$(110)

(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 $94 million as of September 30, 2013, $69 million as of December 31, 2012, $93 million as of September 30, 2012 and $147 million as of December 31, 2011. Cash collateral is included in the "Gross amounts offset in our unaudited Condensed Consolidated Statements of Financial Position" line of this table.

Derivative Instruments Impacts in our Unaudited Condensed Consolidated Statements of Income

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

In millions	Three months ended September 30, 2013	Three months ended September 30, 2012	Nine months ended September 30, 2013	Nine months ended September 30, 2012
Designated as cash flow hedges				
Natural gas contracts - gain reclassified from OCI to cost of goods sold	$ (1)	$ (2)	$ -	$ (2)
Natural gas contracts - gain reclassified from OCI to operation and maintenance expense	-	(2)	-	(1)
Interest rate swaps - loss (gain) reclassified from OCI to interest expense	1	2	(2)	(1)
Not designated as hedges				
Natural gas contracts - net fair value adjustments recorded in operating revenues (1)	(14)	(17)	(16)	(40)
Natural gas contracts - net fair value adjustments recorded in cost of goods sold (2)	-	1	(1)	(2)
Total gain (losses) on derivative instruments	$ (14)	$ (18)	$ (19)	$ (46)

(1) Associated with the fair value of existing derivative instruments at September 30, 2013 and 2012.

(2) Excludes losses recorded in operating revenues or cost of goods sold associated with weather derivatives of $3 million for the nine months ended September 30, 2013 and gains of $14 million for the nine months ended September 30, 2012.

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 nine months ended September 30, 2013 and 2012.

Our expected pre-tax net loss to be reclassified from OCI and recognized in cost of goods sold, operation and maintenance expenses and interest expense in our unaudited Condensed Consolidated Statements of Income over the next 12 months is less than $1 million. These pre-tax deferred gains and losses are recorded in OCI related to natural gas derivative contracts associated with retail operations and Nicor Gas and interest rate swaps with AGL Capital. The expected losses are based upon the fair values of these financial instruments at September 30, 2013.

There have been no other significant changes to our derivative instruments, as described in Note 2 and Note 4 to our Consolidated Financial Statements and related notes included in Item 8 of our 2012 Form 10-K.

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Note 5 - Employee Benefit Plans

Pension Benefits

On December 31, 2012 the AGL Resources Inc. Retirement Plan (AGL Plan), the Nicor Companies Pension and Retirement Plan (Nicor Plan) and the Employees' Retirement Plan of NUI Corporation (NUI Plan) were merged with, and into, the AGL Plan. The eligibility and benefit terms for participants under the Nicor Plan and the NUI Plan were not changed as a result of the plan merger. The AGL Plan is described in Note 6 to our Consolidated Financial Statements and related notes included in Item 8 of our 2012 Form 10-K.

Following are the components of our pension benefit costs for the periods indicated.

	Three months ended September 30,		Nine months ended September 30,	
In millions	2013	2012	2013	2012
Service cost	$ 7	$ 7	$ 22	$ 21
Interest cost	11	10	32	32
Expected return on plan assets	(16)	(16)	(47)	(48)
Net amortization of prior service cost	-	-	(1)	(1)
Recognized actuarial loss	9	9	26	26
Net periodic pension benefit cost	$ 11	$ 10	$ 32	$ 30

Retiree Welfare Benefits

On December 31, 2012 the Nicor Gas Welfare Benefit Plan (Nicor Welfare Plan) was terminated and as of January 1, 2013 all participants under that plan became eligible to participate in the Health and Welfare Plan for Retirees and Inactive Employees of AGL Resources Inc. (AGL Welfare Plan). This change in plan participation eligibility did not affect the benefit terms under the predecessor plans. The Nicor Welfare Plan benefits are now being offered to such participants under the AGL Welfare Plan. The benefits of the AGL Welfare Plan are described in Note 6 to our Consolidated Financial Statements and related notes included in Item 8 of our 2012 Form 10-K.

Following are the components of our retiree welfare benefit costs for the periods indicated.

	Three months ended September 30,		Nine months ended September 30,	
In millions	2013	2012	2013	2012
Service cost	$ 1	$ 1	$ 2	$ 3
Interest cost	3	4	10	12
Expected return on plan assets	(1)	(1)	(4)	(4)
Net amortization of prior service cost	(1)	(1)	(3)	(2)
Recognized actuarial loss	2	2	6	7
Net periodic welfare benefit cost	$ 4	$ 5	$ 11	$ 16

Capitalized Costs

Net pension benefit and net welfare benefit costs are included in operation and maintenance expense, except for a portion that is capitalized as a cost of constructing natural gas distribution facilities.

Contributions

Our employees generally do not contribute to these pension and retiree welfare plans. We fund the qualified pension plan by contributing at least the minimum amounts required by applicable regulations and as recommended by our actuary. However, we may contribute in excess of the minimum required amounts.

As a result of the 2012 merging of our pension plans, there were no contributions required during the nine months ended September 30, 2013. We contributed a combined $32 million to the AGL Plan and the NUI Plan during the same period last year. For more information on our pension plans, see Note 6 to our Consolidated Financial Statements and related notes included in Item 8 of our 2012 Form 10-K.

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Note 6 - 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 that are included in our unaudited Condensed Consolidated Statements of Financial Position. For additional information on our debt, see Note 8 in our Consolidated Financial Statements and related notes in Item 8 of our 2012 Form 10-K.

		September 30, 2013					September 30, 2012			
Dollars in millions	Year(s) due	Weighted average interest rate (1)		Outstanding		Outstanding at December 31, 2012	Weighted average interest rate (1)		Outstanding	
Short-term debt										
Commercial paper - AGL Capital (2)	2013	0.4	%	$ 680		$ 1,063	0.5	%	$ 875	
Commercial paper - Nicor Gas (2)	2013	0.3		152		314	0.5		173	
Total short-term debt		0.4		832		1,377	0.5		1,048	
Current portion of long-term debt and capital leases										
Current portion of long-term debt	n/a	-		-		225	4.6		225	
Current portion of capital leases	n/a	-		-		1	4.9		1	
Total current portion of long-term debt and capital leases		-		$ -		$ 226	4.6	%	$ 226	
Long-term debt - excluding current portion										
Senior notes	2015-2043	5.1	%	$ 2,825		$ 2,325	5.1	%	$ 2,325	
First mortgage bonds	2016-2038	5.6		500		500	5.6		500	
Gas facility revenue bonds	2022-2033	0.8		200		200	1.1		200	
Medium-term notes	2017-2027	7.8		181		181	7.8		181	
Total principal long-term debt		4.9		3,706		3,206	5.0		3,206	
Fair value adjustment of long-term debt (3)	2016-2038	n/a		94		103	n/a		106	
Unamortized debt premium, net	n/a	n/a		16		18	n/a		18	
Total non-principal long-term debt		n/a		110		121	n/a		124	
Total long-term debt				$ 3,816		$ 3,327			$ 3,330	
Total debt				$ 4,648		$ 4,930			$ 4,604	

(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, 2013, the effective interest rates on our commercial paper borrowings were 0.4% for AGL Capital and 0.2% for Nicor Gas.

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

AGL and Nicor Gas Credit Facilities

In October 2013 we notified the administrative agents for our two credit facilities of our request to extend the maturity date of each facility by one year, in accordance with the terms of the respective credit agreements. Subject to receiving the required lender consents for the extensions, the AGL Credit Facility and Nicor Gas Credit Facility maturity dates will be extended to November 10, 2017 and December 15, 2017, respectively. The existing terms, conditions and pricing under the agreements will remain unchanged. Upon receipt of consents from all lenders under the respective agreements, we will pay $1 million in extension fees, which will be amortized over the remaining periods of the respective credit facilities.

Long-Term Debt

On May 16, 2013 we issued $500 million in 30-year senior notes with a fixed interest rate of 4.4%. The net proceeds were used to repay a portion of AGL Capital's commercial paper, including $225 million we borrowed to redeem our senior notes that matured on April 15, 2013. We fully and unconditionally guarantee all debt issued by AGL Capital.

During the first quarter of 2013, we refinanced $200 million of our outstanding tax-exempt gas facility revenue bonds, $180 million of which were previously issued by the New Jersey Economic Development Authority and $20 million of which were previously issued by Brevard County, Florida. The refinancing involved a combination of the issuance of $60 million of refunding bonds to, and the purchase of $140 million of existing bonds by, a syndicate of banks. Our relationship with the syndicate of banks regarding the bonds is governed by an agreement that contains representations, warranties, covenants and default provisions consistent with those contained in similar financing documents of ours. All of the bonds are floating-rate instruments. AGL Resources had no cash receipts or payments in connection with the refinancing. The letters of credit providing credit support for the outstanding revenue bonds along with other related agreements were terminated as a result of the refinancing.

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Interest Rate Swaps

On April 4, 2013 we entered into two ten-year, $50 million fixed-rate forward-starting interest rate swaps to hedge any potential interest rate volatility prior to our issuance of senior notes in the second quarter 2013. The average interest rate on these swaps was 1.98%. Including existing forward-starting interest rate swap hedges, which were executed last year, we had fixed-rate swaps totaling $300 million in notional value at an average interest rate of 1.85%. We designated the forward-starting interest rate swaps as cash flow hedges of our second quarter 2013 senior note issuance. The interest rate swaps were settled on May 16, 2013, the senior note issuance date, at which time we received $6 million in proceeds. The $6 million will be amortized to reduce interest expense over the first 10 years of the 30-year senior notes.

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; however, our goal is to maintain these ratios at levels between 50% and 60%.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 OCI pension adjustments, other post-retirement 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, 2013	December 31, 2012	September 30, 2012
AGL Credit Facility	55 %	58 %	56 %
Nicor Gas Credit Facility	50 %	55 %	51 %

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:

- a maximum leverage ratio
- insolvency events and 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.

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Note 7 - Equity

Our other comprehensive income 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.

In millions (1)	Cash flow hedges	2013 Retirement benefit plans	Total
For the three months ended September 30			
Balance as of June 30	$ (1)	$ (208)	$ (209)
Other comprehensive income, before reclassifications	-	-	-
Amounts reclassified from accumulated other comprehensive income	-	1	1
Net current-period other comprehensive (loss) income	-	1	1
Balance as of September 30	$ (1)	$ (207)	$ (208)
For the nine months ended September 30			
Balance as of December 31, prior year	$ (3)	$ (215)	$ (218)
Other comprehensive income, before reclassifications	-	-	-
Amounts reclassified from accumulated other comprehensive income	2	8	10
Net current-period other comprehensive income	2	8	10
Balance as of September 30	$ (1)	$ (207)	$ (208)

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

The following table provides details of the reclassifications out of accumulated other comprehensive loss for the three and nine months ended September 30, 2013, and the ultimate impact on net income.

In millions	Three Months	Nine Months	
Cash flow hedges			
Natural gas contracts	$(1)	$-	Cost of goods sold
Interest rate contracts	1	(3)	Interest expense, net
Income tax benefit	-	1	
Total cash flow hedges	-	(2)	
Retirement benefit plan amortization of			
Actuarial losses	(6)	(19)	See (2), below
Prior service credits	2	4	See (2), below
Total before income tax	(4)	(15)	
Income tax benefit	3	7	
Total retirement benefit plans	(1)	(8)	

Total reclassification for the period	$ (1)	$ (10)

(1) Amounts in parentheses indicate debits, or reductions, to profit/loss and credits to accumulated other comprehensive loss. Except for retirement benefit plan amounts, the profit/loss impacts are immediate.

(2) Amortization of these accumulated other comprehensive loss components is included in the computation of net periodic benefit cost. See Note 5 for additional details about net periodic benefit cost.

Glossary of Key Terms

Note 8 - Non-Wholly Owned Entities

Variable Interest Entities

On a quarterly basis, we evaluate all of our ownership interests to determine if they represent a VIE as defined by the authoritative accounting guidance on consolidation, and if so, which party is the primary beneficiary. We have determined that SouthStar, a joint venture owned 85% by us and 15% by Piedmont, is our only VIE for which we are the primary beneficiary, which requires us to consolidate its assets, liabilities and statements of income. See Note 10 to our Consolidated Financial Statements and related notes included in Item 8 of our 2012 Form 10-K. Earnings from SouthStar in 2013 and 2012 were allocated entirely in accordance with the ownership interests.

On September 1, 2013 we contributed to SouthStar our Illinois retail energy businesses with approximately 108,000 customers. Additionally, Piedmont contributed to SouthStar $22.5 million in cash to maintain its 15% ownership in the joint venture. In connection with the contribution of our Illinois retail energy businesses, we provided certain limited protections to Piedmont regarding the value of the contributed businesses related to goodwill and other intangible assets. Piedmont’s contribution is reflected as an increase to noncontrolling interest on our unaudited Condensed Consolidated Statements of Financial Position and a financing activity on our unaudited Condensed Consolidated Statements of Cash Flows. These funds were used to reduce our commercial paper borrowings.

SouthStar markets natural gas and related services under the trade name Georgia Natural Gas to retail customers primarily in Georgia, under various other trade names to retail customers in Illinois, Ohio, Florida, Maryland and New York, and to commercial and industrial customers in the southeastern United States.

There have been no significant changes to the primary risks associated with SouthStar beyond those discussed in our risk factors included in Item 1A of our 2012 Form 10-K.

SouthStar’s financial results are seasonal in nature, with the majority of its earnings occurring during the first and fourth quarters of each year. SouthStar’s current assets consist primarily of natural gas inventory, derivative instruments and receivables from its customers. SouthStar also has receivables from us due to its participation in AGL Capital’s commercial paper program. See Note 2 for additional discussions of inventories. SouthStar’s restricted assets consist of customer deposits and were immaterial as of September 30, 2013 and 2012. SouthStar’s current liabilities consist primarily of accounts payable for natural gas purchases, other accrued expenses, customer deposits, derivative instruments and payables to us from its participation in AGL Capital’s commercial paper program.

SouthStar’s other contractual commitments and obligations, including operating leases and agreements with third party providers, do not contain terms that would trigger material financial obligations in the event that such contracts were terminated. 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. We have provided no financial or other support that was not previously contractually required. With the exception of our corporate guarantees, we have not entered into any arrangements that could require us to provide financial support to SouthStar.

Price and volume fluctuations of SouthStar’s natural gas inventories can cause significant variations in our working capital and cash flow from operations. Changes to SouthStar’s working capital resulting from the impact of weather, the timing of customer collections, payments for natural gas purchases and cash collateral amounts that SouthStar maintains to facilitate its derivative instruments also impact our operating cash flow.

Cash flows used in our investing activities include capital expenditures for SouthStar of $2 million for the nine months ended September 30, 2013 and 2012. 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 the nine months ended September 30, 2013 SouthStar distributed $17 million to Piedmont and $14 million during the same period last year. The increase was primarily the result of increased earnings year-over-year and a distribution of excess working capital from the joint venture.

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The following table provides additional information on all of SouthStar's assets and liabilities as of the dates presented, which are consolidated within our unaudited Condensed Consolidated Statements of Financial Position.

	September 30, 2013			December 31, 2012			September 30, 2012		
In millions	Consolidated	SouthStar		Consolidated	SouthStar		Consolidated	SouthStar	
Current assets	$ 2,091	$ 192	9 %	$ 2,668	$ 201	8 %	$ 2,135	$ 152	7 %
Goodwill and other intangible assets	2,063	141	7 %	1,933	-	-	1,913	-	-
Long-term assets and other deferred debits	9,750	11	-	9,540	10	-	9,455	10	-
Total assets	$ 13,904	$ 344	2 %	$ 14,141	$ 211	1 %	$ 13,503	$ 162	1 %
Current liabilities	$ 2,407	$ 73	3 %	$ 3,338	$ 62	2 %	$ 2,764	$ 42	2 %
Long-term liabilities and other deferred credits	7,934	-	-	7,368	-	-	7,341	-	-
Total Liabilities	10,341	73	1 %	10,706	62	1	10,105	42	-
Equity	3,563	271	8 %	3,435	149	4	3,398	120	4
Total liabilities and equity	$ 13,904	$ 344	2 %	$ 14,141	$ 211	1 %	13,503	$ 162	1 %

The following table provides additional information on SouthStar's operating revenues and operating expenses for the periods presented, which are consolidated within our unaudited Condensed Consolidated Statements of Income.

	Three months ended September 30,		Nine months ended September 30,	
In millions	2013	2012	2013	2012
Operating revenues	$ 98	$ 87	$ 464	$ 401
Operating expenses				
Cost of goods sold	81	73	340	286
Operation and maintenance	16	13	49	44
Depreciation and amortization	1	1	2	2
Taxes other than income taxes	-	-	1	2
Total operating expenses	98	87	392	334
Operating income	$ -	$ -	$ 72	$ 67

Equity Method Investments

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 more information about our equity method investments, see Note 10 to our Consolidated Financial Statements under Item 8 included in our 2012 Form 10-K.

In millions	Three months ended September 30, 2013	2012	Nine months ended September 30, 2013	2012
Triton	$ 3	$ 2	$ 7	$ 8
Other	-	-	1	2

Glossary of Key Terms

Note 9 - Commitments, Guarantees and Contingencies

Other than the changes in our debt, see Note 6 herein, there were no significant changes to our contractual obligations beyond those described in Note 11 to our Consolidated Financial Statements and related notes as filed in Item 8 of our 2012 Form 10-K.

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.

Contingencies and Guarantees

Contingent financial commitments, such as financial guarantees, represent obligations that become payable only if certain predefined events occur and include the nature of the guarantee and the maximum potential amount of future payments that could be required of us as the guarantor. 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 and indemnities is remote. No liability has been recorded for such guarantees and indemnifications as the fair value is insignificant.

Regulatory Matters

On December 21, 2012 Atlanta Gas Light filed a petition with the Georgia Commission for approval to resolve an imbalance of approximately 4.8 Bcf 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. We believe that any costs associated with resolving the imbalance are recoverable from Marketers. The resolution of this imbalance will be decided by the Georgia Commission and we are unable to predict the ultimate outcome.

Environmental Matters

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy the effect on the environment of the disposal or release of specified substances at our current and former operating sites. The following table provides more information on the costs related to remediation of our current and former operating sites as of September 30, 2013 and reflects changes in estimates since our 2012 Form 10-K.

In millions	Probabilistic model cost estimates	Engineering estimates	Amount recorded	Expected costs over next twelve months
Illinois	$ 208 - $458	$ 45	$ 248	$ 34
New Jersey	146 - 240	5	150	5
Georgia and Florida	42 - 100	11	55	2
North Carolina	n/a	11	11	7
Total	$ 396 - $798	$ 72	$ 464	$ 48

Our environmental remediation cost liabilities are estimates of future remediation costs for our current and former operating sites that are contaminated. Our estimates are based on conventional engineering estimates and the use of probabilistic models of potential costs when such estimates cannot be made, which is generally the case when remediation has not commenced or during the early years of a remediation effort. For those elements of the program where we cannot perform engineering estimates, there remains considerable variability in future cost estimates. Accordingly, we have established a probabilistic model to determine a range of potential expenditures to remediate and monitor our former operating sites. We cannot, at this time, identify any single number within this range as a better estimate of likely future costs, and we generally have recorded the low end of the range for our probabilistic cost estimates.

As we conduct the actual remediation and enter into cleanup contracts, 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. With the exception of our North Carolina site, these costs are recoverable from our customers as they are paid and, accordingly, we have recorded a regulatory asset associated with the recorded liabilities. For more information on our environmental remediation costs, see Note 11 to our Consolidated Financial Statements and related notes as filed in Item 8 of our 2012 Form 10-K.

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 the company 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 2012 Form 10-K.

PBR Proceeding From 2000 to 2002 Nicor Gas operated a PBR plan for natural gas costs. 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. The PBR plan was under review by the Illinois Commission since 2002 due to allegations that Nicor Gas acted improperly in connection with the plan. On June 27, 2002, the Citizens Utility Board (CUB) filed a motion to reopen the record in the Illinois Commission's proceedings to review the PBR plan (the "Illinois Commission Proceedings"). As a result of the motion to reopen, Nicor Gas entered into a stipulation with the staff of the Illinois Commission and CUB providing for additional discovery. The Illinois Attorney General's Office (IAGO) has also intervened in this matter. In addition, the IAGO issued Civil Investigation Demands (CIDs) to CUB and the Illinois Commission staff. The CIDs ordered that CUB and the Illinois Commission staff produce all documents relating to any claims that Nicor Gas may have presented, or caused to be presented, regarding false information related to its PBR plan. We have committed to cooperate fully in the reviews of the PBR plan.

The Nicor Board of Directors directed management to, among other things, make appropriate adjustments to account for, and fully address, the adverse consequences to ratepayers, and conduct a detailed study of the adequacy of internal accounting and regulatory controls. The adjustments were made in prior years' financial statements resulting in a $25 million liability. Included in this $25 million liability is a $4 million loss contingency. A $2 million adjustment to the previously recorded liability, which is discussed below, was made in 2004 increasing the recorded liability to $27 million. By the end of 2003, Nicor Gas completed steps to correct the weaknesses and deficiencies identified in the detailed study of the adequacy of internal controls.

On February 5, 2003 CUB filed a motion for $27 million in sanctions against Nicor Gas in the Illinois Commission Proceedings. In that motion, CUB alleged that Nicor Gas' responses to certain CUB data requests were false. Also on February 5, 2003, CUB stated in a press release that, in addition to $27 million in sanctions, it would seek additional refunds to consumers. On March 5, 2003 the Illinois Commission staff filed a response brief in support of CUB's motion for sanctions. On May 1, 2003 the Administrative Law Judges assigned to the proceeding issued a ruling denying CUB's motion for sanctions. CUB has filed an appeal of the motion for sanctions with the Illinois Commission, and the Illinois Commission has indicated that it will not rule on the appeal until the final disposition of the Illinois Commission Proceedings. It is not possible to determine how the Illinois Commission will resolve the claims of CUB or other parties to the Illinois Commission Proceedings.

In 2004 Nicor Gas became aware of additional information relating to the activities of individuals affecting the PBR plan for the period from 1999 through 2002, including information consisting of third party documents and recordings of telephone conversations from Entergy-Koch Trading, LP (EKT), a natural gas, storage and transportation trader and consultant with whom Nicor Gas did business under the PBR plan. Review of additional information completed in 2004 resulted in the $2 million adjustment to the previously recorded liability referenced above.

The evidentiary hearings on this matter were stayed in 2004 in order to permit the parties to undertake additional third party discovery from EKT. In December 2006 the additional third party discovery from EKT was obtained and the Administrative Law Judge issued a scheduling order that provided for Nicor Gas to submit direct testimony by April 13, 2007. Nicor Gas submitted direct testimony in April 2007, rebuttal testimony in April 2011 and surrebuttal testimony in December 2011. In surrebuttal testimony, we sought $6 million, which included interest due to us of $2 million, as of December 31, 2011. The staff of the Illinois Commission, IAGO and CUB submitted direct testimony to the Illinois Commission in April 2009 and rebuttal testimony in October 2011. In rebuttal testimony, the staff of the Illinois Commission, IAGO and CUB requested refunds of $85 million, $255 million and $305 million, respectively.

In February 2012 we committed to a stipulated resolution of issues, which existed prior to our acquisition of Nicor Gas, with the staff of the Illinois Commission that would include crediting Nicor Gas customers $64 million. There were no new developments between the date of acquisition and the date of the stipulated resolution. The CUB and IAGO were not parties to the stipulated resolution and continue to pursue their claims in this proceeding. Evidentiary hearings before the Administrative Law Judges were held during the first quarter of 2012 and post-trial legal briefs from the parties were submitted during the second quarter of 2012. Following the submission of legal briefs, on November 5, 2012 the Administrative Law Judges issued a proposed order for a refund of $72 million to ratepayers. During the fourth quarter of 2012, we increased our accrual by $8 million for a total of $72 million as a result of these developments and its effect on the estimated liability.

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On June 7, 2013 the Illinois Commission issued an order requiring us to refund $72 million to Nicor Gas' current customers over a 12-month period. We maintain that the appropriate PBR refund is $64 million, consistent with the stipulated resolution with the staff of the Illinois Commission, and filed an appeal for the amount in excess of that specified in the stipulated resolution. The CUB has also filed an appeal. During the third quarter of 2013 the Illinois Commission denied all applications for rehearing of its June order and the Illinois appellate court denied Nicor Gas's request for a stay on the obligation to refund the amount in excess of $64 million. On July 1, 2013 we began refunding customers the full $72 million through our purchased gas adjustment mechanism. The amount refunded is based upon actual natural gas throughput and $5 million was refunded during the third quarter of 2013.

Nicor Services Warranty Product Actions Nicor Gas, Nicor Services and Nicor are defendants in a putative class action initially filed in September 2011, in state court in Cook County, Illinois. The plaintiffs purport to represent a class of customers of Nicor Gas who purchased the Gas Line Comfort Guard product from Nicor Services. The plaintiffs variously allege that the marketing, sale and billing of the Nicor Services Gas Line Comfort Guard violate the Illinois Consumer Fraud and Deceptive Business Practices Act, constitute common law fraud and result in unjust enrichment of Nicor Services and Nicor Gas. The plaintiffs seek, on behalf of the classes they purport to represent, actual and punitive damages, interest, costs, attorney fees and injunctive relief. While we are unable to predict the outcome of these matters or to reasonably estimate our potential exposure related thereto, if any, and have not recorded a liability associated with this contingency, the final disposition of this matter is not expected to have a material adverse impact on our liquidity or financial condition.

Other We also are involved in an investigation by the United States Environmental Protection Agency regarding the applicable regulatory requirements for polychlorinated biphenyl in the Nicor Gas distribution system. While we are unable to predict the outcome of this matter or to reasonably estimate our potential exposure related thereto, if any, and have not recorded a liability associated with this contingency, the final disposition of this matter is not expected to have a material adverse impact on our liquidity or financial condition.

For additional litigation information on these matters, see Note 11 in our Consolidated Financial Statements and related notes in Item 8 of our 2012 Form 10-K.

In addition to the matters set forth above, we 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.

Glossary of Key Terms

Note 10 - Segment Information

Our operating segments comprise revenue-generating components of our company for which we produce separate financial information internally that we regularly use 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 five operating segments - distribution operations, retail operations, wholesale services, midstream operations, cargo shipping and other, a non-operating segment.

Our distribution operations segment is the largest component of our business and includes natural gas local distribution utilities in seven states - Illinois, Georgia, Virginia, New Jersey, Florida, Tennessee and Maryland. 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 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, as well as various businesses that market retail energy-related products and services to residential and small business customers primarily in Illinois, such as warranty protection solutions to customers and customer move connection services for other utilities. Our wholesale services segment includes natural gas asset management and related logistics activities for each of our utilities, except Nicor Gas, as well as for nonaffiliated companies, natural gas storage arbitrage and related activities. Our midstream operations segment includes our non-utility storage, fuels and pipeline operations, including the development and operation of high-deliverability natural gas storage assets.

Our cargo shipping segment transports containerized freight between Florida, the eastern coast of Canada, the Bahamas and the Caribbean region. Our cargo shipping segment also includes amounts related to cargo insurance coverage sold to our customers and other third parties. Our cargo shipping segment’s vessels are under foreign registry, and its containers are considered instruments of international trade. Although the majority of its long-lived assets are foreign owned and its revenues are derived from foreign operations, the functional currency is generally the United States dollar. Our cargo shipping segment also includes an equity investment in Triton, a cargo container leasing business. Profits and losses are generally allocated to investors’ capital accounts in proportion to their capital contributions. Our investment in Triton is accounted for under the equity method, and our share of earnings is reported within other income in our unaudited Condensed Consolidated Statements of Income.

Our other segment includes intercompany eliminations and aggregated subsidiaries that are individually not significant enough to be reportable.

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

You should not consider EBIT an alternative to, or a more meaningful indicator of, our operating performance than operating income or net income as determined in accordance with GAAP. In addition, our EBIT may not be comparable to a similarly titled measure of another company. The reconciliations of EBIT to operating income, earnings before income taxes and net income for the periods presented are as follows:

In millions	Three months ended September 30, 2013	2012	Nine months ended September 30, 2013	2012
Operating income	$ 82	$ 54	$ 503	$ 407
Other income	7	6	19	19
EBIT	89	60	522	426
Interest expense	43	45	135	137
Earnings before income taxes	46	15	387	289
Income taxes	18	6	145	106
Net income	$ 28	$ 9	$ 242	$ 183

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Information by segment on our Statements of Financial Position as of December 31, 2012 is as follows:

In millions	Identifiable and total assets (1)	Goodwill
Distribution operations	$ 11,320	$ 1,640
Retail operations	511	122
Wholesale services	1,218	-
Midstream operations	720	14
Cargo shipping	464	61
Other (2)	(92)	-
Consolidated	$ 14,141	$ 1,837

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

(2) The assets of our other segment consist primarily of cash and cash equivalents and PP&E, and reflect the effect of intercompany eliminations.

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, 2013

In millions	Distribution operations	Retail operations	Wholesale services	Midstream operations	Cargo shipping	Other and intercompany eliminations (4)	Consolidated
Operating revenues from external parties	$420	$138	$13	$19	$89	$ (4)	$ 675
Intercompany revenues (1)	36	-	-	-	-	(36)	-
Total operating revenues	456	138	13	19	89	(40)	675
Operating expenses							
Cost of goods sold	111	92	1	9	55	(39)	229
Operation and maintenance	150	31	13	5	29	(2)	226
Depreciation and amortization	91	6	-	5	4	3	109
Taxes other than income taxes	22	1	1	1	2	2	29
Total operating expenses	374	130	15	20	90	(36)	593
Operating income (loss)	82	8	(2)	(1)	(1)	(4)	82
Other income	4	-	-	-	3	-	7
EBIT	$86	$8	$(2)	$(1)	$2	$ (4)	$ 89
Capital expenditures	$200	$3	$-	$3	$6	$ 5	$ 217

Three months ended September 30, 2012

In millions	Distribution operations	Retail operations	Wholesale services	Midstream operations	Cargo shipping	Other and intercompany eliminations (4)	Consolidated
Operating revenues from external parties	$405	$118	$(12)	$22	$83	$ (2)	$ 614
Intercompany revenues (1)	37	-	-	-	-	(37)	-
Total operating revenues	442	118	(12)	22	83	(39)	614
Operating expenses							
Cost of goods sold	107	83	-	12	51	(38)	215
Operation and maintenance	148	26	11	4	29	(6)	212
Depreciation and amortization	88	3	-	4	5	4	104
Taxes other than income taxes	21	1	1	1	1	2	27
Nicor merger expenses (2)	-	-	-	-	-	2	2
Total operating expenses	364	113	12	21	86	(36)	560
Operating income (loss)	78	5	(24)	1	(3)	(3)	54
Other income	2	-	1	-	2	1	6
EBIT	$80	$5	$(23)	$1	$(1)	$ (2)	$ 60
Capital expenditures	$189	$3	$1	$18	$1	$ 7	$ 219

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Nine months ended September 30, 2013

In millions	Distribution operations	Retail operations	Wholesale services	Midstream operations	Cargo shipping	Other and intercompany eliminations (4)	Consolidated
Operating revenues from external parties	$2,299	$605	$73	$58	$264	$ (11)	$ 3,288
Intercompany revenues (1)	134	-	-	-	-	(134)	-
Total operating revenues	2,433	605	73	58	264	(145)	3,288
Operating expenses							
Cost of goods sold	1,142	402	21	25	162	(143)	1,609
Operation and maintenance	494	94	36	17	87	(10)	718
Depreciation and amortization	271	16	1	13	14	10	325
Taxes other than income taxes	124	3	2	4	5	6	144
Total operating expenses	2,031	515	60	59	268	(137)	2,796
Gain on sale of Compass Energy	-	-	11	-	-	-	11
Operating income (loss)	402	90	24	(1)	(4)	(8)	503
Other income (loss)	11	-	-	2	7	(1)	19
EBIT	$413	$90	$24	$1	$3	$ (9)	$ 522
Identifiable and total assets (3)	$11,300	$652	$930	$726	$464	$ (168)	$ 13,904
Goodwill	$1,640	$168	$-	$14	$61	$ -	$ 1,883
Capital expenditures	$495	$7	$-	$11	$9	$ 13	$ 535

Nine months ended September 30, 2012

In millions	Distribution operations	Retail operations	Wholesale services	Midstream operations	Cargo shipping	Other and intercompany eliminations (4)	Consolidated
Operating revenues from external parties	$1,848	$517	$59	$56	$247	$ (23)	$ 2,704
	124	-	-	-	-	(124)	-

Intercompany revenues (1)							
Total operating revenues	1,972	517	59	56	247	(147)	2,704
Operating expenses							
Cost of goods sold	767	342	34	24	152	(145)	1,174
Operation and maintenance	473	83	35	13	83	(12)	675
Depreciation and amortization	262	10	1	10	17	10	310
Taxes other than income taxes	103	3	3	4	4	6	123
Nicor merger expenses (2)	-	-	-	-	-	15	15
Total operating expenses	1,605	438	73	51	256	(126)	2,297
Operating income (loss)	367	79	(14)	5	(9)	(21)	407
Other income	7	-	1	1	8	2	19
EBIT	$374	$79	$(13)	$6	$(1)	$ (19)	$ 426
Identifiable and total assets (3)	$10,970	$472	$970	$712	$482	$ (103)	$ 13,503
Goodwill	$1,591	$122	$-	$14	$90	$ -	$ 1,817
Capital expenditures	$457	$7	$1	$77	$2	$ 25	$ 569

(1) Intercompany revenues - wholesale services records its energy marketing and risk management revenues on a net basis and its total operating revenues include intercompany revenues of $69 million and $312 million for the three and nine months ended September 30, 2013, respectively, and $93 million and $230 million for the three and nine months ended September 30, 2012, respectively.

(2) Transaction expenses associated with the Nicor merger are shown separately to better compare year-over-year results.

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

(4) The assets of our other segment consist primarily of cash and cash equivalents and PP&E, and reflect the effect of intercompany eliminations.

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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 notes to our unaudited Condensed Consolidated Financial Statements in this quarterly filing, as well as our 2012 Form 10-K. 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 vary 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 impact of our depreciation study for Nicor Gas and related legislation; 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 and on our cargo shipping business; 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 under United States federal securities 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 the following five operating and reporting segments – distribution operations, retail operations, wholesale services, midstream operations and cargo shipping 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 10 to our unaudited Condensed Consolidated Financial Statements herein and Item 1, "Business" of our 2012 Form 10-K. Following are summarized recent developments for our operating segments.

Overview In the first nine months of 2013, we benefited from the return to more normal weather as compared to the historically warm weather in 2012. Excluding weather, we achieved growth in our operating margins during the first nine months of 2013 primarily as a result of our regulatory infrastructure programs in our distribution operations, targeted acquisition growth in our retail operations and higher contributions from commercial activity in our wholesale operations.

We continue to effectively manage costs and leverage our shared services model across our businesses to largely overcome inflationary effects. Our operation and maintenance expenses in the first nine months of 2013 were largely consistent with prior years as we achieved efficiencies that offset inflationary costs and an increase in incentive compensation that reflects year over year performance. Our operation and maintenance expenses include a modest increase in bad debt expense compared to 2012 for some of our businesses as a result of colder weather and higher natural gas prices, which resulted in higher average customer bills.

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Distribution Operations At September 30, 2013 our seven utilities within distribution operations served approximately 4.5 million end-use customers with their primary focus being the safe and reliable delivery of natural gas.

Nicor Gas In June 2013 the Illinois Commission issued an order requiring us to refund $72 million to Nicor Gas' current customers over a 12-month period in connection with Nicor Gas' operation of a PBR plan from 2000 to 2002. We continue to maintain that the appropriate PBR refund is $64 million, consistent with our stipulated resolution agreed to by Nicor Gas and the staff of the Illinois Commission, and have appealed the amount in excess of that specified in the stipulated resolution. There is no deadline for the Illinois Appellate Court to act on the appeal and we do not expect a decision before the middle of 2014. On July 1, 2013 Nicor Gas began refunding the $72 million through its purchased gas adjustment mechanism based on natural gas throughput, with approximately 40% expected to be refunded in 2013 and 60% expected to be refunded in 2014. During the third quarter of 2013 $5 million was refunded. Nicor Gas previously accrued $72 million for this contingent liability, which is in line with the order issued by the Illinois Commission. See Note 9 to our unaudited Condensed Consolidated Financial Statements for additional information.

In June 2013 we entered into an OTC weather derivative to reduce the risk of lower operating margins related to the risk of significantly warmer-than-normal weather in Illinois during the fourth quarter of 2013. The weather derivative is based on fourth quarter 2013 Heating Degree Days at Chicago Midway International Airport and is a cash-settled option. If weather is warmer than normal during the fourth quarter of 2013 the option would partially offset lower operating margin that would result from lower customer usage. Since the option would not be exercised if heating degree days are equal to or higher than normal, the option would not offset margins that are higher because of colder than normal weather. We continue to evaluate ways to mitigate our Illinois weather risk on an ongoing basis.

In July 2013 Illinois enacted legislation that will allow Nicor Gas to provide more widespread safety and reliability enhancements to its system in a timelier manner than under traditional utility regulation, and to pass along lower program costs to its customers. The legislation requires that rate increases to customer bills as a result of the investment shall not exceed an annual average 4.0% of base rate revenues. We expect to submit a plan for approval by the Illinois Commission in mid-2014.

In July 2013 Illinois enacted legislation that provides a streamlined process to revise depreciation rates for natural gas utilities. On August 30, 2013 Nicor Gas filed a depreciation study with the Illinois Commission that proposed a composite depreciation rate of 3.07% compared to the current composite rate of 4.10%. The composite depreciation rate, if applied to Nicor Gas' property, plant and equipment as of December 31, 2012, would have resulted in a decrease of approximately $50 million in annual depreciation expense. In October 2013 the Illinois Commission approved our proposed composite depreciation rate for Nicor Gas. The depreciation rate is effective as of the date the depreciation study was filed and an adjustment to depreciation expense will be recognized during the fourth quarter of 2013. This will reduce our depreciation expense by $4 million for the period from August 30, 2013 through September 30, 2013. A lower composite depreciation rate is not expected to impact customer rates and we believe that it would provide an incentive to increase Nicor Gas' capital expenditures, potentially creating more jobs in the communities that are served by Nicor Gas.

In September 2013 Nicor Gas filed its second Energy Efficiency Plan, which outlines program offerings and therm reduction goals with spending of $93 million over the three-year period June 2014 through May 2017. Nicor Gas' first Energy Efficiency Program is currently in its third year and will end in May 2014. Although there is no statutory deadline for approval of gas utility plans, Nicor Gas requested approval in the same 5 month timeframe, or by March 1, 2014, as established by statute for electric utilities. The new plan must be implemented by June 1, 2014. A procedural schedule has not been established for this case.

Atlanta Gas Light In December 2012 Atlanta Gas Light filed a petition with the Georgia Commission for approval to resolve an imbalance of approximately 4.8 Bcf 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. We believe that any costs associated with resolving the imbalance are recoverable from Marketers. The resolution of this imbalance will be decided by the Georgia Commission and we are unable to predict the ultimate outcome.

Virginia Natural Gas In May 2013 the Virginia Commission approved Virginia Natural Gas' Conservation and Ratemaking Efficiency (CARE) plan. The plan provides for a modified CARE plan that includes a more limited set of conservation programs and measures at a reduced cost of $2 million over a three-year period.

Chattanooga Gas In April 2013 legislation was signed into law that gives the Tennessee Authority the ability to approve alternative regulatory mechanisms. The law allows the Tennessee Authority to: (i) implement separate rate adjustment mechanisms that track specific costs, (ii) implement annual rate reviews in lieu of traditional rate cases and (iii) adopt other policies or procedures that permit a more timely review and revision of rates, streamline the regulatory process, and reduce the cost and time associated with the traditional ratemaking processes.

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In April 2013 Chattanooga Gas filed a proposal with the Tennessee Authority to extend its energy conservation programs and associated rate adjustment mechanism that adjusts rates to recover reduced operating revenues as a result of reduced customer usage. In August 2013 a status conference was held by the Tennessee Authority and a procedural schedule was established whereby the Tennessee Authority's Staff will issue a report on the evaluation of the conservation programs, which is expected in 2014. After the Tennessee Authority issues its report, Chattanooga Gas will be required to file a report on the impacts of the rate adjustment mechanism within 45 days. Interveners will then have 30 days to respond to Chattanooga Gas's report and recommendations. The Tennessee Authority granted Chattanooga Gas an extension of its rate adjustment mechanism until the completion of the proceeding.

Retail Operations Our retail operations businesses serve approximately 600,000 energy customers and approximately 1.2 million service contracts in Florida, Georgia, Illinois, Indiana, Kentucky, Ohio, Maryland, Massachusetts, New York, Pennsylvania and West Virginia. SouthStar, Nicor Advanced Energy and Nicor Solutions generate earnings through the sale of natural gas to residential, commercial and industrial customers, primarily in Georgia and Illinois where we capture spreads between wholesale and retail natural gas prices. Additionally, these businesses offer our customers energy-related products that provide for natural gas price stability and utility bill management. These products mitigate and/or eliminate the risks to customers of colder-than-normal weather and/or changes in natural gas prices. We charge a fee or premium for these services. Our retail operations businesses also provide warranty protection and home solutions that include gas and electric line repair, equipment repair, insurance and maintenance through Pivotal Home Solutions and represent customers who are on monthly service contracts or warranty products billed at a fixed monthly amount.

In September 2013 we contributed our wholly owned subsidiaries Nicor Advanced Energy and Nicor Solutions, our Illinois retail energy subsidiaries, to our SouthStar joint venture. Piedmont contributed $22.5 million in cash to SouthStar to maintain its 15% ownership interest in the joint venture. In connection with the contribution of our Illinois retail energy businesses, we provided certain limited protections to Piedmont regarding the value of the contributed businesses related to goodwill and other intangible assets. See Note 8 for more information.

As described in Note 2 to our unaudited Condensed Consolidated Financial Statements, during June 2013, our retail operations segment acquired approximately 33,000 residential and commercial relationships in Illinois for $32 million. The transaction significantly increases the size of our retail energy customer portfolio in Illinois with minimal incremental operating expenses. We expect this transaction to result in approximately $4 million of EBIT during 2013.

In January 2013 our retail operations segment acquired approximately 500,000 service plans and certain other assets for $120 million, plus $2 million of working capital. We believe this acquisition will provide an enhanced platform for growth and continued expansion of this business into a number of key markets.

Wholesale Services Our wholesale services segment consists of our wholly owned subsidiary Sequent and engages in asset management and optimization, storage, transportation, producer and peaking services and wholesale marketing of natural gas across the United States and in Canada. It also provides natural gas asset management and/or related logistics services for most of our utilities, as well as for non-affiliated companies. In April 2013 the Tennessee Authority authorized an extension of the asset management agreement between Chattanooga Gas and Sequent. The terms of the agreement remain unchanged, except the expiration date is now March 2015.

In May 2013 we sold Compass Energy, a non-regulated retail natural gas business supplying commercial and industrial customers. We received an initial cash payment of $12 million, which resulted in an $11 million pre-tax gain ($5 million net of tax). Additionally, we are eligible to receive contingent cash consideration up to $8 million with a guaranteed minimum receipt of $3 million. The amount of the contingent cash consideration will be received from the buyer over a five-year earn out period based upon the financial performance of Compass Energy. See Note 2 to our unaudited Condensed Consolidated Financial Statements for additional information.

Midstream Operations Our midstream operations segment includes a number of businesses that are related and complementary to our primary business. The most significant of these businesses is our natural gas storage business, which develops and operates high-deliverability underground natural gas storage assets primarily in the Gulf Coast region of the United States and in northern California. While this business can generate additional revenue during times of peak market demand for natural gas storage services, many of our natural gas storage facilities are covered under a portfolio of short, medium and long-term contracts at fixed market rates.

Golden Triangle Storage's Cavern 1 began commercial operations in September 2010 and Cavern 2 began commercial operations in September 2012. Cavern 1 is currently going through a process to assess its working gas capacity. The process began in early 2013 and is expected to continue during the fourth quarter of 2013. Limited commercial service resumed in the third quarter 2013 and full commercial service is expected to resume in the first quarter of 2014. Cavern 2 has been covering, and will continue to cover, the obligations of Cavern 1 during this process. Central Valley, located in northern California, began commercial operations for firm customers during the second quarter of 2012.

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Through our wholly owned subsidiary Cypress Creek Gas Storage, LLC and as a result of our merger with Nicor, we own a 50% interest in Sawgrass Storage, LLC (Sawgrass Storage), a joint venture between us and a privately held energy exploration and production company. Sawgrass Storage was granted certification from the Federal Energy Regulatory Commission (FERC) in March 2012 for the development of an underground natural gas storage facility in Louisiana with 30 Bcf of working gas capacity (expandable to 40 Bcf). The FERC certificate is set to expire in March 2014 if not extended. Given the current weakness in the natural gas storage market and the impending expiration of the FERC certificate, we along with our joint venture partner continue to evaluate our on-going strategy for the Sawgrass Storage facility. Currently, our investment in Sawgrass Storage is $9 million, which could potentially be written-off or impaired in the event of a continued decline in natural gas market fundamentals and the rates for contracting availability capacity, the FERC certificate not being extended or other strategic decisions made by us, our joint venture partner or the joint venture.

Cargo Shipping Our cargo shipping segment consists of Tropical Shipping; multiple wholly owned foreign subsidiaries of Tropical Shipping that are treated as disregarded entities for United States income tax purposes; Seven Seas, a wholly owned domestic cargo insurance company; and an equity investment in Triton, a cargo container leasing business.

In September 2013 we entered into a contract to sell one of our 12 cargo vessels. We will replace this vessel with a chartered vessel, which is expected to provide greater capacity and operational flexibility.

Natural Gas Market Fundamentals Volatility in the natural gas market arises from a number of factors, such as weather fluctuations or changes in supply of, or demand for, natural gas in different regions of the country or portions of the interstate and intrastate gas pipeline systems. 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 our retail operations and wholesale services segments to capture value from location and seasonal spreads. Additionally, changes in commodity prices subject a significant portion of our operations to earnings variability. Since 2011 the volatility of the daily Henry Hub spot market prices for natural gas – a benchmark measure for natural gas generally - in the United States has been significantly lower than it had been in previous years. This is the result of a robust natural gas supply, the weak economy and ample natural gas storage.

Our utility natural gas acquisition strategy is designed to secure sufficient supplies of natural gas and the rights to physically flow natural gas between delivery points in order to meet the needs of our utility customers and to hedge gas prices and location spreads to manage costs, reduce price volatility for our utility customers and maintain a competitive advantage.

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 hedge gains and correspondingly increases in EBIT, while an increase in natural gas prices or a widening of transportation spreads generally results in hedge losses and correspondingly 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.

It is possible that natural gas prices will remain low for an extended period based on current levels of excess supply relative to market demand for natural gas, in part due to abundant sources of new shale natural gas reserves and the lack of demand by commercial and industrial enterprises. However, as economic conditions continue to improve, the demand for natural gas may increase, natural gas prices could rise and higher volatility could return to the natural gas markets. Consequently, we are working to reposition our wholesale services business model with respect to fixed costs, and the types of contracts pursued and executed.

The market fundamentals of midstream operations storage business are cyclical, and as discussed above, 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. In 2013 expiring storage capacity contracts were re-subscribed at lower prices and we anticipate these lower natural gas prices to continue throughout 2013 and 2014 as compared to historical averages. Due to the current market storage rates, we did not re-contract 2.0 Bcf at Golden Triangle Storage and intend to provide other services until market conditions improve to support longer-term contracts. As of September 30, 2013 the overall average firm subscription rate per facility is as follows:

	Average Monthly Rate per Dekatherm
Jefferson Island (1)	$0.111
Golden Triangle (1)	0.182
Central Valley	0.130

(1) Includes firm capacity contracted by Sequent at April 1, 2013 of 1.5 Bcf at an average monthly rate of $0.07 per dekatherm at Jefferson Island and 2 Bcf at an average monthly rate of $0.125 per dekatherm at Golden Triangle.

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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 our distribution operations and retail operations segments 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 generally incurred relatively equally over any given year. The revenues of our cargo shipping business are generally higher in the fourth quarter, due to increased tourist-related shipments as the hotels, resorts, and cruise ships typically have increased occupancy rates commencing in the fourth quarter and increasing further into the first quarter as well as consumer spending generally increasing during traditional holiday periods. Revenues for cargo shipping are also impacted during the fourth quarter by peak season surcharges. Thus, our operating results vary significantly from quarter to quarter as a result of seasonality.

We evaluate segment performance using the measures of operating margin and EBIT, which include the effects of corporate expense allocations. 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. EBIT is also a non-GAAP measure that includes operating income and other income and expenses. Items that we do not include in EBIT are financing costs, including interest and debt expense and income taxes, each of which we evaluate on a consolidated basis.

We believe operating margin is a better indicator than operating revenues of the contribution resulting from customer growth in our distribution operations segment, 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 our retail operations, wholesale services, midstream operations and cargo shipping segments, since it is a direct measure of operating margin generated before overhead costs.

We believe EBIT is a useful measurement of our operating segments' performance because it provides information that can be used to evaluate the effectiveness of our businesses from an operational perspective, exclusive of the costs to finance those activities and exclusive of income taxes, neither of which is directly relevant to the efficiency of those operations. You should not consider operating margin or EBIT an alternative to, or a more meaningful indicator of, our operating performance than operating income or net income attributable to AGL Resources Inc. as determined in accordance with GAAP. In addition, our operating margin and EBIT measures may not be comparable to similarly titled measures of other companies.

We believe presenting the non-GAAP measurements of basic and diluted earnings per share - as adjusted, which excludes Nicor merger-related expenses, provides investors with an additional measure of our performance. Adjusted basic and diluted earnings per share should not be considered an alternative to, or a more meaningful indicator of, our operating performance than our GAAP basic and diluted earnings per share. The following table reconciles operating revenue and operating margin to operating income, and EBIT to earnings before income taxes and net income, and our GAAP basic and diluted earnings per common share to our non-GAAP basic and diluted earnings per share – as adjusted, together with other consolidated financial information for the periods presented.

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In millions, except per share amounts	Three months ended September 30, 2013	2012	Change	Nine months ended September 30, 2013	2012	Change
Operating revenues	$675	$614	$61	$3,288	$2,704	$584
Cost of goods sold	(229)	(215)	(14)	(1,609)	(1,174)	(435)
Revenue tax expense (1)	(8)	(8)	-	(81)	(62)	(19)
Operating margin	438	391	47	1,598	1,468	130
Operating expenses (2)	(364)	(343)	(21)	(1,187)	(1,108)	(79)
Revenue tax expense (1)	8	8	-	81	62	19
Gain on sale of Compass Energy	-	-	-	11	-	11
Nicor merger expenses (2)	-	(2)	2	-	(15)	15
Operating income	82	54	28	503	407	96
Other income	7	6	1	19	19	-
EBIT	89	60	29	522	426	96
Interest expenses	(43)	(45)	2	(135)	(137)	2
Earnings before income taxes	46	15	31	387	289	98
Income tax expenses	(18)	(6)	(12)	(145)	(106)	(39)
Net income	28	9	19	242	183	59
Less net income attributable to the noncontrolling interest	-	-	-	(11)	(10)	(1)
Net income attributable to AGL Resources Inc.	$28	$9	$19	$231	$173	$58
Per common share data						
Basic earnings per common share attributable to AGL Resources Inc. common shareholders (3)	$0.24	$0.08	$0.16	$1.96	$1.48	$0.48
Transaction costs of Nicor merger	-	0.01	(0.01)	-	0.08	(0.08)
Basic earnings per share - as adjusted	$0.24	$0.09	$0.15	$1.96	$1.56	$0.40
Diluted earnings per common share attributable to AGL Resources Inc. common shareholders (3)	$0.24	$0.08	$0.16	$1.96	$1.48	$0.48
Transaction costs of Nicor merger	-	0.01	(0.01)	-	0.08	(0.08)
Diluted earnings per share - as adjusted	$0.24	$0.09	$0.15	$1.96	$1.56	$0.40

(1) Adjusted for Nicor Gas' revenue tax expenses, which are passed directly through to customers.

(2) Expenses associated with the Nicor merger are part of operating expenses, but are shown separately to better compare year-over-year results.

(3) Sale of Compass Energy generated basic and diluted EPS of $0.04 for the nine months ended September 30, 2013.

For the third quarter of 2013 our net income attributable to AGL Resources Inc. increased by $19 million compared to the same period last year.

- The increase was primarily the result of higher commercial activity in our wholesale services segment, increased operating margin at distribution operations as a result of increased regulatory infrastructure program revenues at Atlanta Gas Light, increased customer usage and customer growth for most of our utilities, as well as the acquisition of retail service customers in our retail operations segment.
- This increase was partially offset by increased incentive compensation expenses across our businesses as our incentive compensation expense increased from significantly below targeted levels in 2012 to above targeted levels in 2013 based on improved financial and operational performance and higher bad debt expense at retail operations primarily as a result of higher natural gas prices compared to the same period in the prior year.

For the nine months ended September 30, 2013 our net income attributable to AGL Resources Inc. increased by $58 million, or 34%, compared to the same period last year.

- The increase was primarily the result of increased operating margin at distribution operations and retail operations due to colder weather and increased average customer usage compared to the same period in the prior year, increased regulatory infrastructure program revenues at Atlanta Gas Light and the acquisition of retail services customers in January 2013.
- The increase also was favorably impacted by higher commercial activity and the $11 million pre-tax gain on the sale of Compass Energy in our wholesale services segment.
- This increase was partially offset by increased incentive compensation expenses across our businesses as our incentive compensation expense increased from significantly below targeted levels in 2012 to above targeted levels in 2013 based on improved financial and operational performance. In addition, our bad debt expense increased at retail operations primarily as a result of colder weather combined with natural gas prices that were higher than in the same period of the prior year.
- During the nine months ended September 30, 2012 we recorded $15 million ($9 million net of tax) of Nicor merger related expenses.

For the third quarter of 2013 our income tax expense increased by $12 million compared to the third quarter of 2012 and by $39 million for the nine months ended September 30, 2013 compared to the same period of 2012. The increases were primarily due to higher consolidated earnings, as previously discussed. Our income tax expense is determined from earnings before income taxes less net income attributable to noncontrolling interest.

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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 gas on our distribution systems. With the exception of Nicor Gas and Florida City Gas, we have various regulatory mechanisms, such as weather normalization mechanisms, which limit our exposure to weather changes within typical ranges in each of our utilities' respective service areas. However, our customers in Illinois and 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.

Weather (Heating Degree Days)	Nine months ended September 30, Normal	2013	2012	2013 vs. 2012 colder		2013 vs. normal colder	
Illinois (1) (2)	3,680	3,922	2,973	32	%	7	%
Georgia (1)	1,591	1,640	1,056	55	%	3	%

(1) Normal represents the ten-year average from January 1, 2003 through September 30, 2012, 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.

During the nine months ended September 30, 2013 we experienced weather in Illinois that was 7% colder-than-normal and 32% colder than the same period in the prior year. Georgia also experienced 3% colder-than-normal weather, and 55% colder than the same period last year.

Customers Our customer metrics highlight the average number of customers for which we provide services and are provided in the table below. 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 year-over-year consolidated utility customer growth rate was 0.4% for the three and nine months ended September 30, 2013. We anticipate overall utility customer growth trends for 2013 to improve compared to prior year as a result of the improving economy and the reduced volatility of natural gas prices.

Our energy customers at retail operations are primarily located in Georgia and Illinois. Our market share in Georgia has decreased primarily as a result of a highly competitive marketing environment, which we expect will continue for the foreseeable future. In 2013 our retail operations segment intends to continue its efforts to enter and expand within targeted markets to increase its energy customers and expand our service contracts to include our service territories in Virginia and Tennessee.

Customers and service contracts (average end-use, in thousands)	Three months ended September 30, 2013		2012		2013 vs. 2012 % change		Nine months ended September 30, 2013		2012		2013 vs. 2012 % change	
Distribution operations customers	4,447		4,429		0.4	%	4,480		4,461		0.4	%
Retail operations												
Energy customers (1)	621		600		4	%	617		630		(2	)%
Service contracts (2)	1,168		664		76	%	1,119		689		62	%
	31	%	32	%	(3	)%	32	%	32	%	-	%

Market share in Georgia	

(1) A portion of the energy customers represents customer equivalents in Ohio, which are computed by the actual delivered volumes divided by the expected average customer usage. The increase for the three months ended September 30, 2013 primarily represents the addition of approximately 33,000 residential and commercial customer relationships acquired in Illinois in June 2013. The decrease for the nine months ended September 30, 2013 is primarily due to our contract to serve approximately 50,000 customer equivalents that ended in April 2012.

(2) Increase primarily due to acquisition of approximately 500,000 service contracts on January 31, 2013.

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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. 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. Additionally, our cargo shipping segment measures the volume of shipments during the period in TEUs. We continue to seek opportunities to profitably increase our number of TEUs and maximize the utilization of our containers and vessels. Our volume metrics are presented in the following table:

Volumes	Three months ended September 30, 2013	2012	2013 vs. 2012 % change	Nine months ended September 30, 2013	2012	2013 vs. 2012 % change
Distribution operations (In Bcf)						
Firm	71	75	(5)%	487	408	19 %
Interruptible	27	26	4 %	83	79	5 %
Total	98	101	(3)%	570	487	17 %
Retail operations (In Bcf)						
Georgia firm	3	3	0 %	26	20	30 %
Illinois	2	-	N/A	7	5	40 %
Other (1)	1	1	0 %	5	6	(17)%
Wholesale services						
Daily physical sales (Bcf / day)	5.4	5.3	2 %	5.7	5.4	6 %
Cargo shipping (TEU's - in thousands)						
Shipments	46	43	7 %	136	124	10 %

	As of September 30, 2013	2012
Midstream operations		
Working natural gas capacity (in Bcf) (2)	31.8	30.3
% of firm capacity under subscription by third parties (3)	33 %	48 %

(1) Includes Florida, Maryland, New York and Ohio.

(2) Golden Triangle Storage's Cavern 1 is currently going through a process to assess its working gas capacity. The process began in early 2013 and is expected to continue with full commercial service operations resuming in the first quarter of 2014. Limited commercial operations resumed in the third quarter 2013. Cavern 2 has been covering obligations of Cavern 1 during the process.

(3) The percentage of capacity under subscription does not include 3.5 Bcf of capacity under contract with Sequent at September 30, 2013 and 3 Bcf of capacity under contract with Sequent at September 30, 2012.

Three and nine months ended September 30, 2013 compared to the same periods ended September 30, 2012

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

	Three months ended September 30, 2013			Three months ended September 30, 2012		
In millions	Operating margin (1) (2)	Operating expenses (2)	EBIT (1)	Operating margin (1) (2)	Operating expenses (2) (3)	EBIT (1)
Distribution operations	$337	$255	$86	$327	$249	$80
Retail operations	46	38	8	35	30	5
Wholesale services	12	14	(2)	(12)	12	(23)
Midstream operations	10	11	(1)	10	9	1
Cargo shipping	34	35	2	32	35	(1)
Other	(1)	3	(4)	(1)	2	(2)
Consolidated	$438	$356	$89	$391	$337	$60

	Nine months ended September 30, 2013			Nine months ended September 30, 2012		
In millions	Operating margin (1) (2)	Operating expenses (2)	EBIT (1) (4)	Operating margin (1) (2)	Operating expenses (2) (3)	EBIT (1)
Distribution operations	$1,210	$808	$413	$1,143	$776	$374
Retail operations	203	113	90	175	96	79
Wholesale services (4)	52	39	24	25	39	(13)
Midstream operations	33	34	1	32	27	6
Cargo shipping	102	106	3	95	104	(1)
Other	(2)	6	(9)	(2)	19	(19)
Consolidated	$1,598	$1,106	$522	$1,468	$1,061	$426

(1) These are non-GAAP measures. A reconciliation of operating margin to operating income and EBIT to earnings before income taxes and net income is contained in "Results of Operations" herein. See Note 10 to our unaudited Condensed Consolidated Financial Statements under Item 1 herein for additional segment information.
(2) Operating margin and expense are adjusted for revenue tax expense for Nicor Gas, which is passed directly through to customers.
(3) Includes $2 million and $15 million in Nicor merger transaction expenses for the three and nine months ended September 30, 2012, respectively.
(4) EBIT for the nine months ended September 30, 2013, includes $11 million pre-tax gain on sale of Compass Energy.

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.

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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 gas consumed. For the three and nine months ended September 30, 2013 distribution operations' EBIT increased by $6 million or 8% and $39 million or 10%, respectively, compared to prior year, as shown in the following table.

In millions	Three months ended	Nine months ended
EBIT - for September 30, 2012	$ 80	$ 374
Operating margin		
Increased operating margin mainly driven by colder weather, higher customer usage and customer growth compared to prior year	3	30
Increased rider revenues primarily as a result of energy efficiency program recoveries at Nicor Gas	-	12
Increased revenues from regulatory infrastructure programs, primarily at Atlanta Gas Light	7	25
Increase in operating margin	10	67
Operating expenses		
Increased rider expenses primarily as a result of energy efficiency program expenses at Nicor Gas	-	12
Increased incentive compensation costs that reflect year over year performance	4	13
Increased depreciation expense as a result of increased PP&E from infrastructure additions and improvements	3	9
Other	(1)	(2)
Increase in operating expenses	6	32
Increased AFUDC equity primarily from STRIDE projects at Atlanta Gas Light	2	4
EBIT - for September 30, 2013	$ 86	$ 413

Retail Operations

Our retail operations segment, which consists of SouthStar and several businesses that provide energy-related products and services to retail markets, also 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 and nine months ended September 30, 2013 retail operations' EBIT increased by $3 million or 60% and $11 million or 14%, 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, 2012	$ 5	$ 79
Operating margin		
Increased margin primarily related to average customer usage in Georgia due to	1	13

increased demand and colder weather relative to prior year, net of weather hedges		
Increased margin primarily due to 2013 retail acquisitions in January and June	12	24
Storage inventory write-down (LOCOM) in 2012	-	3
Decrease related to higher gas costs and lower retail price spreads, partially offset by favorable customer portfolio	(2)	(12)
Increase in operating margin	11	28
Operating expenses		
Increased expenses primarily due to 2013 retail acquisitions in January and June	6	15
Increased bad debt expense primarily related to colder weather and higher natural gas prices	1	3
Other	1	(1)
Increase in operating expenses	8	17
EBIT - for September 30, 2013	$ 8	$ 90

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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. EBIT for our wholesale services segment 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 and nine months ended September 30, 2013, wholesale services' EBIT increased by $21 million and $37 million, respectively, compared to prior year, as shown in the following table.

In millions	Three months ended	Nine months ended
EBIT - for September 30, 2012	$ (23)	$ (13)
Operating margin		
Change in commercial activity largely driven by the withdrawal of a portion of the storage inventory economically hedged at the end of 2012, colder weather and increased cash optimization opportunities in the supply-constrained Northeast corridor	29	62
Change in value on storage hedges as a result of changes in NYMEX natural gas prices	17	22
Change in value on transportation and forward commodity hedges from price movements related to natural gas transportation positions	(21)	(59)
Change in storage inventory LOCOM adjustment, net of estimated recoveries	(1)	2
Increase in operating margin	24	27
Operating expenses		
Increased incentive compensation expense, offset by lower costs due to sale of Compass Energy and other costs	2	-
Increase in operating expenses	2	-
Gain on sale of Compass Energy	-	11
Decrease in other income	(1)	(1)
EBIT - for September 30, 2013	$ (2)	$ 24

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

	Three months ended September 30,		Nine months ended September 30,	
In millions	2013	2012	2013	2012
Commercial activity recognized	$ 27	$ (2)	$ 79	$ 17
Gain (loss) on storage hedges	2	(15)	9	(13)
(Loss) gain on transportation and forward commodity hedges	(16)	5	(31)	28

Storage inventory LOCOM adjustment, net of estimated recoveries		(1	)		-			(5	)		(7	)
Operating margin	$	12		$	(12	)	$	52		$	25	

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 hedge gains and losses as associated physical transactions occur in the period. Additionally, the commercial activity includes operating margin generated and recognized in the current period. For the first nine months of 2013, commercial activity increased significantly due to (i) the recognition of operating margin resulting from the withdrawal of storage inventory hedged at the end of 2012 that was included in the storage withdrawal schedule with a value of $27 million as of December 31, 2012, (ii) the effects of colder weather and (iii) increased cash optimization opportunities related to certain of our transportation portfolio positions, particularly in the Northeastern United States. As previously discussed, our operating margin opportunities continued to be lower in 2013 due to lower volatility and lower seasonal price spreads associated with our storage portfolio.

Change in storage and transportation hedges Seasonal (storage) and geographical location (transportation) spreads and overall natural gas price volatility in general continued to remain low relative to historical periods. During the third quarter and the nine months ended September 30, 2013, the downward movement in natural gas prices resulted in storage hedge gains as compared to storage hedge losses last year resulting from an upward movement in the natural gas prices. Gains on our transportation positions in 2012 were primarily due to large transportation spreads at the time our transportation positions were executed and the subsequent narrowing of regional transportation spreads. However, similar to the first half of the year, significant volatility continued during the current quarter at natural gas receipt and delivery points throughout the Northeast corridor relative to natural gas receipt and delivery constraints in the region, resulting in losses on our transportation position. These losses are temporary and based on current expectations will largely be recovered in the fourth quarter of 2013 and the first quarter of 2014 when the related physical transactions occur and are recognized.

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Withdrawal schedule Sequent's expected natural gas withdrawals from storage are presented in the following table along with the operating revenues expected at the time of withdrawal. Sequent's expected operating revenues exclude storage demand charges but are net of the estimated impact of profit sharing under our asset management agreements and reflect the amounts that are realizable in future periods based on the inventory withdrawal schedule and forward natural gas prices at September 30, 2013 and 2012. A portion of Sequent's storage inventory is economically hedged with futures contracts, which results in realization of substantially fixed 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 2012 Form 10-K.

Withdrawal schedule	Total storage (in Bcf) (WACOG $3.29)	Expected operating revenues (1) (in millions)
2013		
Fourth quarter	39	13
2014		
First quarter	16	8
Second quarter	2	2
Total at September 30, 2013	57	$ 23
Total at December 31, 2012	51	$ 27
Total at September 30, 2012	58	$ 65

(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.

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 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. For the three and nine months ended September 30, 2013 midstream operations' EBIT decreased by $2 million and $5 million, respectively, compared to prior year, as shown in the following table.

In millions	Three months ended	Nine months ended
EBIT - for September 30, 2012	$ 1	$ 6
Operating margin		
Increased revenues at Golden Triangle as a result of Cavern 2 beginning commercial service in third quarter 2012, as well as revenue due to entry into LNG market, partially offset by lower revenues at Jefferson Island as a result of lower subscription rates and lower revenues at Central Valley	-	1
Increase in operating margin	-	1
Operating expenses		
Increased depreciation, property taxes, storage expenses, payroll and outside	2	7

services largely due to Central Valley and Cavern 2 at Golden Triangle beginning commercial service in 2012 and entry into the LNG market				
Increase in operating expenses		2		7
Increase from equity investment in Horizon Pipeline		-		1
EBIT - for September 30, 2013	$	(1	) $	1

Cargo Shipping

Our cargo shipping segment's primary activity is transporting containerized freight in the Bahamas and the Caribbean, a region that has historically been characterized by modest market growth and intense competition. Such shipments consist primarily of southbound cargo such as building materials, food and other necessities for developers, distributors and residents in the region, as well as tourist-related shipments intended for use in hotels and resorts and on cruise ships. The balance of the cargo consists primarily of interisland shipments of consumer staples and northbound shipments of apparel, rum and agricultural products. Other related services, such as inland transportation and cargo insurance, are also provided within the cargo shipping segment. Our cargo shipping segment also includes an equity investment in Triton, a cargo container leasing business. For more information about our investment in Triton, see Note 10 to our Consolidated Financial Statements under Item 8 included in our 2012 Form 10-K.

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For the third quarter of 2013 cargo shipping's EBIT increased by $3 million compared to the third quarter of 2012 and increased by $4 million for the nine months ended September 30, 2013, compared to prior year, as shown in the following table.

In millions	Three months ended	Nine months ended
EBIT - for September 30, 2012	$ (1)	$ (1)
Operating margin		
TEU volume increased due to market share expansion and modest improvement in economic conditions in our service regions; leverage effect of volume increases on fuel expense	3	15
Increased (decreased) average TEU rates due to general ocean freight rate increases, changes in cargo mix and competitive pressures	2	(6)
Increased brokerage and container storage costs combined primarily with lower other non-shipping revenues	(3)	(2)
Increase in operating margin	2	7
Operating expenses		
Increased payroll, benefits, outside services and other	1	5
Decreased depreciation expense	(1)	(3)
Increase in operating expenses	-	2
Increase (decrease) from equity investment income in Triton	1	(1)
EBIT - for September 30, 2013	$ 2	$ 3

Liquidity and Capital Resources

Overview The acquisition of natural gas and pipeline capacity, payment of dividends and funding of working capital needs are our most significant short-term financing requirements. The need for long-term capital is driven primarily by capital expenditures and maturities of long-term debt. The liquidity required to fund our working capital, capital expenditures and other cash needs is primarily provided by our operating activities. Our short-term cash requirements not met with cash from operations 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. 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. Consistent with this strategy, in May 2013 we issued $500 million in 30-year senior notes with a fixed interest rate of 4.4%.

Our capital market strategy is focused on maintaining strong Consolidated Statements of Financial Position, ensuring ample cash resources and daily liquidity, accessing capital markets at favorable times as necessary, managing critical business risks and maintaining a balanced capital structure through the appropriate issuance of equity or long-term debt securities.

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 in the amount it can dividend or loan to affiliates and is not permitted to make money pool loans to affiliates. Dividends are allowed only to the extent of Nicor Gas' retained earnings balance, which was $473 million at September 30, 2013.

We believe the amounts available to us under our senior notes, AGL Credit Facility and Nicor Gas Credit Facility, through the issuance of debt and equity securities, combined with cash provided by operating activities, 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. 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.

As of September 30, 2013 and 2012, and December 31, 2012, we had $74 million, $76 million and $80 million, respectively, of cash and short-term investments held by Tropical Shipping. This cash and investments are available for use by our other operations only if we repatriate a portion of Tropical Shipping's earnings in the form of a dividend, and pay a significant amount of United States income tax. See Note 12 to our Consolidated Financial Statements under Item 8 included in our 2012 Form 10-K for additional information on our income taxes.

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We will continue to evaluate our need to increase available liquidity based on our view of working capital requirements, including the impact of changes in natural gas prices, liquidity requirements established by rating agencies and other factors. See Item 1A, "Risk Factors," in our 2012 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 at 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 2013 are discussed in "Liquidity and Capital Resources" under the caption 'Cash Flows from Financing Activities' in our 2012 Form 10-K and our 2013 estimated expenditures have increased from $212 million to $262 million.

Dollars in millions	Utility	Expenditures in 2013	Expenditures since project inception	Miles of pipe replaced	Year project began	Anticipated year of completion
STRIDE program (1)						
Pipeline replacement program	Atlanta Gas Light	$ 114	$ 796	2,690	1998	2013
Integrated System Reinforcement Program	Atlanta Gas Light	22	246	n/a	2009	2013
Integrated Customer Growth Program	Atlanta Gas Light	11	40	n/a	2010	2013
Enhanced infrastructure program	Elizabethtown Gas	1	109	96	2009	2017
Accelerated infrastructure program	Virginia Natural Gas	17	33	72	2012	2017
Total		$ 165	$ 1,224	2,858		

(1) The i-VPR program began in 2013 and as of September 30, 2013 has incurred less than $1 million of expenditures.

Nicor Gas In July 2013 Illinois enacted legislation that provides for infrastructure investment by natural gas utilities serving more than 700,000 customers, which includes Nicor Gas. This bill will allow Nicor Gas to provide more widespread safety and reliability enhancements to its pipelines in a timelier manner than under traditional utility regulation, and pass along lower program costs to our customers. We expect to submit a plan for approval by the Illinois Commission in mid-2014.

Atlanta Gas Light Our STRIDE program is comprised of the ongoing pipeline replacement program, the Integrated System Reinforcement Program (i-SRP), the Integrated Customer Growth Program (i-CGP) and the Integrated Vintage Plastic Replacement Program (i-VPR). The purpose of the i-SRP is to upgrade our distribution system and liquefied natural gas facilities in Georgia, improve our peak day system reliability and operational flexibility, and create a platform to meet long-term forecasted growth. Our i-CGP authorizes Atlanta Gas Light to extend its pipeline facilities to serve customers in areas without pipeline access and create new economic development opportunities in Georgia. The STRIDE program requires us to file an updated ten-year forecast of infrastructure requirements under i-SRP along with a new construction plan every three years for review and approval by the Georgia Commission. These programs remain on track for completion in 2013.

We filed a new $260 million STRIDE program in August 2013, $214 million of which will be for i-SRP related projects and $46 million of which will be for i-CGP related projects. In addition to the $260 million request in new investment and programs, Atlanta Gas Light also requested an additional $5 million of investment for i-CGP projects from the initial i-CGP plan. Under the current procedural schedule, hearings will be held in November 2013 with a ruling scheduled for December 2013.

In November 2012 we filed i-VPR with the Georgia Commission, as a new component of STRIDE. This program would replace aging plastic pipe that was installed primarily in the mid-1960’s to the early 1980’s. We have identified approximately 3,300 miles of vintage plastic mains in our system that potentially should be considered for replacement over the next 15 - 20 years as it reaches the end of its useful life. Our initial request to the Georgia Commission was to replace approximately 756 miles over the next three to four years. The estimated cost of the first tranche of pipe to be replaced under i-VPR is $275 million. In August, 2013 the Georgia Commission voted unanimously to approve the replacement of 756 miles of vintage plastic pipe over four years at an estimated cost of $275 million. Additional reporting requirements and monitoring by the staff of the Georgia Commission were also included in the stipulation, which authorized a phased-in approach to funding the program.

The approximately $275 million construction program will be funded through a rider of $0.48 through December 2014. Additional surcharges of $0.48 and $0.49 will be applied in January 2015 and January 2016, respectively, and will continue through 2025.

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Elizabethtown Gas In August 2013 the New Jersey BPU approved the recovery of investments under the accelerated enhanced infrastructure program through a permanent adjustment to base rates. The base rate adjustments associated with this program were previously implemented on a provisional basis. Also in August 2013 our request under the accelerated infrastructure replacement (AIR) program was approved by the New Jersey BPU under modified terms from Elizabethtown Gas' initial request. The approval allows for infrastructure investment of $115 million over four years, effective as of September 2013. Carrying charges on the additional capital spend will be accrued and deferred at a weighted average cost for capital of 6.65%, and there will be no adjustment to base rates until Elizabethtown Gas files its next rate case. We agreed to file a general rate case by September 2016. This rate case requirement is consistent with the approvals the New Jersey BPU has given to other gas utilities in the state related to their similar filings.

In March 2013, the BPU issued an order inviting the submission of proposals from utilities for infrastructure upgrades designed to protect New Jersey's utility infrastructure from future major storm events. In September 2013 in response to this request, Elizabethtown Gas filed for a Natural Gas Distribution Utility Reinforcement Effort (ENDURE), a program that will improve the distribution system resiliency against coastal storms and floods. Under the proposed plan, Elizabethtown will invest $15 million in infrastructure and related facilities and communication planning over a one year period beginning January 2014. Elizabethtown Gas is proposing to accrue and defer carrying charges on the investment until its next rate case proceeding.

Virginia Natural Gas In January 2012 Virginia Natural Gas filed SAVE, an accelerated infrastructure replacement program, with the Virginia Commission, which involves replacing aging infrastructure as prioritized through Virginia Natural Gas' distribution integrity management program. SAVE was filed in accordance with a Virginia statute providing a regulatory cost recovery mechanism to recover the costs associated with certain infrastructure replacement programs. The Virginia Commission approved SAVE in June 2012 for a five-year period, which includes a maximum allowance for capital expenditure of $25 million per year, not to exceed $105 million in total. SAVE is subject to annual review by the Virginia Commission. We began recovering costs based on this program through a rate rider that became effective August 1, 2012. In May 2013 we filed our annual SAVE rate update detailing the first year performance and our expected future budget, which is subject to review and approval by the Virginia Commission. The rate update was approved with minor modifications by the Virginia Commission in July 2013 and became effective as of August 2013.

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, prospects 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, 2013 and reflects no change from December 31, 2012.

	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-2	F1
Senior unsecured	BBB+	Baa1	BBB+	BBB+	A3	A+
Senior secured	n/a	n/a	n/a	A	A1	AA-
Ratings outlook	Stable	Stable	Stable	Stable	Stable	Stable

Our credit ratings depend largely on our financial performance, and 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.

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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, our goal, subject to extraordinary events such as acquisitions, is to maintain these ratios at levels between 50% and 60%. These ratios, as defined within our debt agreements, include standby letters of credit, performance/surety bonds and exclude accumulated OCI items related to non-cash pension adjustments, other post-retirement 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, 2013	December 31, 2012	September 30, 2012
AGL Credit Facility	55 %	58 %	56 %
Nicor Gas Credit Facility	50 %	55 %	51 %

We were in compliance with all of our debt provisions and covenants, both financial and non-financial, for all periods presented.

Our ratio of total debt to total capitalization, on a consolidated basis, is typically greater at the beginning of the Heating Season, as we make additional short-term borrowings to fund our natural gas purchases and meet our working capital requirements. We attempt to maintain our ratio of total debt to total capitalization in a target range of 50% to 60%. Accomplishing this capital structure objective and maintaining sufficient cash flow are necessary to maintain attractive credit ratings. For more information on our default provisions, see Note 6 to our unaudited Condensed Consolidated Financial Statements under Item 1 herein. The components of our capital structure, as calculated from our unaudited Condensed Consolidated Statements of Financial Position, as of the dates indicated are provided in the following table.

	September 30, 2013	December 31, 2012	September 30, 2012
Short-term debt	10 %	16 %	13 %
Long-term debt	47	43	45
Total debt	57	59	58
Equity	43	41	42
Total capitalization	100 %	100 %	100 %

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

	Nine months ended September 30,		
In millions	2013	2012	Variance
Net cash provided by (used in):			
Operating activities	$ 1,070	$ 1,032	$ 38
Investing activities	(661)	(577)	(84)
Financing activities	(409)	(433)	24
Net increase in cash and cash equivalents	-	22	(22)
Cash and cash equivalents at beginning of period	131	69	62
Cash and cash equivalents at end of period	$ 131	$ 91	$ 40

Cash Flow from Operating Activities The $38 million increase in cash from operating activities for the nine months ended September 30, 2013 compared to the same period in 2012 was primarily related to increased cash provided by (i) net energy marketing receivables and payables, due to higher cash received in the current period related to higher sales volumes at higher prices in December 2012 versus the same period in 2011, (ii) prepaid taxes, due to decreased prepaid positions for federal and state income taxes, and (iii) lower payments for incentive compensation in 2013 as a result of reduced earnings in 2012 as compared to the prior year. This increase in cash provided by operating activities was partially offset by decreased cash provided by (i) receivables, other than energy marketing, due to colder weather in 2013, which resulted in higher volumes primarily at distribution operations and retail operations that will be collected in future periods and (ii) inventories, due to higher inventory injections at distribution operations, retail energy and midstream operations.

Cash Flow from Investing Activities The $84 million increase in cash flow used in investing activities was primarily the result of our $122 million acquisition of approximately 500,000 service plans during the first quarter of 2013 and our $32 million acquisition of approximately 33,000 residential and commercial energy customer relationships in Illinois during the second quarter of 2013. This increase was partially offset by decreased spending for property, plant and equipment expenditures of $34 million, a net decrease in short-term investments of $24 million and $12 million from the sale of Compass Energy.

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Cash Flow from Financing Activities The decreased use of cash for our financing activities for the nine months ended September 30, 2013 compared to the same period in 2012 was primarily the result of our May 2013 issuance of senior notes and the cash contribution received from Piedmont that was used to reduce our commercial paper borrowings, partially offset by higher short-term debt payments of $272 million and our April 2013 payment of $225 million of senior notes.

At September 30, 2013 our variable-rate debt was 23% of our total debt, compared to 32%, as of December 31, 2012 and 27% as of September 30, 2012. The decrease from December 31, 2012 was primarily due to decreased commercial paper borrowings. As of September 30, 2013 our commercial paper borrowings of $832 million were 40% lower than as of December 31, 2012, primarily a result of our repayment of a portion of AGL Capital’s commercial paper borrowings. For more information on our debt, see Note 6 to our unaudited Condensed Consolidated Financial Statements under Item 1 herein.

In April 2013 our $225 million 4.45% senior notes matured. Repayment of these senior notes was funded through our commercial paper program. In May 2013, we issued $500 million in 30-year senior notes. The net proceeds of $494 million were used to repay a portion of AGL Capital’s commercial paper, including $225 million we borrowed to repay our senior notes that matured in April 2013.

Short-term Debt Our short-term debt comprises borrowings under our commercial paper programs and current portions of our senior notes and capital leases. 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	$ 680	$ 757	$ 380	$ 1,064
Commercial paper - Nicor Gas	152	57	-	314
Senior notes	-	86	-	225
Capital leases	-	1	-	1
Total short-term debt and current portions of long-term debt and capital leases	$ 832	$ 901	$ 380	$ 1,604

(1) As of September 30, 2013.

(2) For the nine months ended September 30, 2013. The minimum and largest balances outstanding for each short-term 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.

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.

Increasing natural gas commodity prices can have a significant impact on our commercial paper borrowings. Based on current natural gas prices and our expected injection plan, a $1 increase NYMEX price change could result in a $24 million change of working capital requirements during the 2013 injection season. This range is sensitive to the timing of storage injections and withdrawals, collateral requirements and our portfolio position. 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.

In October 2013 we notified the administrative agents for our two credit facilities of our request to extend the maturity date of each facility by one year, in accordance with the terms of their respective agreements. Subject to receiving the required lender consents for the extensions, the AGL Credit Facility and Nicor Gas Credit facility maturity dates will be extended to November 10, 2017 and December 15, 2017, respectively. The existing terms, conditions and pricing under the agreements remain unchanged. We anticipate paying a fee to the consenting lenders for the one-year extension. Upon receipt of consents from all lenders under the agreements, we would pay $1 million in extension fees, which will be amortized over the remaining period of the respective credit facilities.

The lenders under our credit facilities and lines of credit are major financial institutions with $2.2 billion of committed balances and all had investment grade credit ratings as of September 30, 2013. It is possible that one or more lending commitments could be unavailable to us if the lender defaulted due to lack of funds or insolvency. However, based on our current assessment of our lenders' creditworthiness, we believe the risk of lender default is minimal.

Long-term Debt Our long-term debt matures more than one year from September 30, 2013 and consists of medium-term notes: Series A, Series B, and Series C, which we issued under an indenture during December 1989; senior notes; first mortgage bonds; and gas facility revenue bonds.

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During the first quarter of 2013 we refinanced $200 million of our outstanding tax-exempt gas facility revenue bonds, $180 million of which were previously issued by the New Jersey Economic Development Authority and $20 million of which were previously issued by Brevard County, Florida. The refinancing involved a combination of the issuance of $60 million of refunding bonds to and the purchase of $140 million of existing bonds by a syndicate of banks. Our relationship with the syndicate of banks regarding the bonds is governed by an agreement that contains representations, warranties, covenants and default provisions consistent with those contained in similar financing documents of ours. All of the bonds remain floating-rate instruments and we anticipate interest expense savings of approximately $2 million annually over the 5.5 year term of the agreement. AGL Resources had no cash receipts or payments in connection with the refinancing. The letters of credit providing credit support for the retired bonds along with other related agreements were terminated as a result of the refinancing. Costs associated with these refinancings will be amortized over the remaining life of the bonds.

Noncontrolling Interest We recorded cash distributions for SouthStar's dividend distributions to Piedmont of $17 million for the nine months ended September 30, 2013 and $14 million for the same period in 2012. The primary reason for the increase in the distribution to Piedmont during the current year was increased earnings for 2012 compared to 2011. In September 2013 Piedmont contributed to SouthStar $22.5 million in cash to maintain its 15% ownership in the joint venture subsequent to our contribution of our Illinois retail energy businesses.

Dividends on Common Stock Our common stock dividend payments were $166 million for the nine months ended September 30, 2013 and $150 million for the same period in 2012. The increase is primarily due to the $0.10 stub period dividend paid in December 2011, which reduced the dividend paid in the first quarter of 2012 by the same amount and the annual dividend increase of $0.04 per share.

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.

Other than the changes in our debt, see Note 6 to our unaudited Condensed Consolidated Financial Statements under Part I, Item 1 herein, there were no significant changes to our contractual obligations described in Note 11 to our Consolidated Financial Statements and related notes as filed in Item 8 of our 2012 Form 10-K.

Pension and retiree welfare plan obligations Primarily as a result of merging our pension plans in December 2012, no contributions were required thus far this year or are expected for the remainder of 2013. During the first nine months of 2012 we contributed $32 million to certain of our qualified pension plans and an additional $8 million in October 2012 for a total of $40 million through October 2012. Based on the current funding status of our merged pension plan, we do not believe additional contributions to the pension plan will be required during 2013.

During the nine months ended September 30, 2013 we recorded net periodic benefit costs of $43 million related to our defined benefit plans compared to $46 million during the same period last year. The final annual expense is expected to be $57 million, before capitalization, for 2013 compared to actual expense of $61 million for 2012. We estimate that during the remainder of 2013 we will record net periodic benefit costs of $14 million.

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 2012 Form 10-K. Our critical accounting estimates used in the preparation of our unaudited Condensed Consolidated Financial Statements include the following:

- Regulatory Infrastructure Program Liabilities
- Environmental Remediation Liabilities
- Derivatives and Hedging Activities
- Goodwill and Other Intangible Assets
- Contingencies
- Pension and Retiree Welfare Plans
- Provisions for Income Taxes

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Goodwill Impairment Testing Our annual goodwill impairment analysis that was performed during the fourth quarter of 2012 indicated that the estimated fair value of a reporting unit within our midstream operations segment, with $14 million of goodwill, exceeded its carrying value by less than 10% as of our testing date. During the third quarter of 2013 we identified a reduction in the near-term market rates at which we are able to re-contract capacity at our storage facilities. We considered the decline in near term rates as an indicator of potential impairment and, accordingly, conducted an interim goodwill impairment analysis during the third quarter of 2013.

The fair value of this reporting unit was determined utilizing the income and market approaches. The market approach is based on observable transactions of comparable companies and assets. The income approach estimates fair value based upon the present value of estimated future cash flows discounted at an appropriate risk-free rate. These forecasts contain a degree of uncertainty, and changes in the projected cash flows could significantly increase or decrease the estimated fair value of the reporting unit. Key assumptions used in the income approach included long-term growth rates used to determine the terminal value at the end of the discrete forecast period, current and future rates charged for contracted capacity and a discount rate. The discount rate is applied to estimated future cash flows and is one of the most significant assumptions used to determine fair value under the income approach. As interest rates rise, the calculated fair values will decrease. The terminal growth rate was based on a combination of historical and forecasted statistics for real gross domestic product and personal income. The rates we charge to customers for capacity in the storage caverns are based on internal and external rates forecasts.

While near-term rates have declined, management’s forecast for long-term rates have not significantly changed since our 2012 impairment analysis was performed. Our interim goodwill impairment test indicated that the estimated fair value of this reporting unit continues to exceed its carrying value. We continue to monitor this reporting unit for impairment and note that continued declines in capacity or subscription rates or for a sustained period at the current market rates may result in an impairment of goodwill. Our risk of impairment of the underlying long-lived assets is not estimated to be significant because the assets have long remaining useful lives and authoritative accounting guidance requires such assets to be tested for impairment based on the basis of undiscounted cash flows over their remaining useful lives.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

We are exposed to risks associated with natural gas prices, interest rates, credit and fuel prices. Natural gas price risk is defined as the potential loss that we may incur as a result of changes in the fair value of natural gas. Interest rate risk results from our portfolio of debt and equity instruments that we issue to provide financing and liquidity for our business. Credit risk results from the extension of credit throughout all aspects of our business, but is particularly concentrated at Atlanta Gas Light in distribution operations and in wholesale services. Our fuel price risk is primarily in cargo shipping, which is partially reduced through fuel surcharges. Our use of derivative instruments is governed by a risk management policy, approved and monitored by our Risk Management Committee (RMC).

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 4 of our unaudited Condensed Consolidated Financial Statements.

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, 2013 and 2012.

	Derivative instruments average values at September 30, (1)	
In millions	2013	2012
Asset	$ 106	$ 213
Liability	42	97

(1) Excludes cash collateral amounts.

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	Derivative instruments fair values netted with cash collateral at		
In millions	September 30, 2013	December 31, 2012	September 30, 2012
Asset	$ 112	$ 144	$ 159
Liability	44	39	42

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.

	Three months ended September 30,		Nine months ended September 30,	
In millions	2013	2012	2013	2012
Net fair value of derivative instruments outstanding at beginning of period	$ (3)	$ 23	$ 36	$ 31
Derivative instruments realized or otherwise settled during period	(11)	(16)	(55)	(65)
Net fair value of derivative instruments acquired during period	-	-	-	-
Change in net fair value of derivative instruments	(12)	17	(7)	58
Net fair value of derivative instruments outstanding at end of period	(26)	24	(26)	24
Netting of cash collateral	94	93	94	93
Cash collateral and net fair value of derivative instruments outstanding at end of period	$ 68	$ 117	$ 68	$ 117

The sources of our net fair value at September 30, 2013, are as follows.

In millions	Prices actively quoted (Level 1) (1)	Significant other observable inputs (Level 2) (2)
Mature through 2013	$ (1)	$ 6
Mature 2014 - 2015	(40)	10
Mature 2016 - 2017	(4)	3
Total derivative instruments (3)	$ (45)	$ 19

(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.

Value at risk 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. 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 immaterial, permitting us to operate within relatively low VaR limits. We employ daily risk testing, using both VaR and stress testing, to evaluate the risks of our open positions. Our VaR is determined on a 95% confidence interval and a 1-day holding period. In simple terms, this means that 95% of the time, the risk of loss from a portfolio of positions is expected to be less than or equal to the amount of VaR calculated.

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 for all positions, our portfolio positions for the periods presented had the following VaRs.

	Three months ended September 30,		Nine months ended September 30,	
In millions	2013	2012	2013	2012
Period end	$ 2.5	$ 1.7	$ 2.5	$ 1.7
Average	2.3	1.5	2.0	2.2
High	3.1	1.8	3.1	4.8
Low	1.9	1.3	1.2	1.3

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 $1.0 billion of variable-rate debt outstanding at September 30, 2013, a 100 basis point change in market interest rates would have resulted in an increase in pre-tax interest expense of $10 million on an annualized basis.

We use 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.

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We have $300 million of 6.4% senior notes due in July 2016. In May 2011 we entered into interest rate swaps related to these senior notes to effectively convert $250 million from a fixed-rate to a variable-rate obligation. On September 6, 2012, we settled this $250 million interest rate swap, which resulted in our receipt of a $17 million cash payment.

On May 16, 2013 we issued $500 million of 30-year senior notes with a fixed interest rate of 4.4%. We had entered into $300 million, in notional amount, of fixed-rate forward-starting interest rate swaps to hedge the first ten years of potential interest rate volatility prior to this issuance. The weighted average interest rate of these swaps was a 10-year United States Treasury rate of 1.85%. On May 16, 2013 we settled these swaps, which resulted in our receipt of a $6 million cash payment.

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 hedged interest payments. For additional information, see Note 4 to our unaudited Condensed Consolidated Financial Statements under 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 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 each 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, 2013 our top 20 counterparties represented approximately 52% of the total counterparty exposure of $333 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, 2013 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	Sept. 30, 2013	Dec. 31, 2012	Sept. 30, 2012	Sept. 30,2013	Dec. 31, 2012	Sept. 30, 2012
Netting agreements in place:						
Counterparty is investment grade	$ 310	$ 485	$ 293	$ 229	$ 282	$ 201
Counterparty is non-investment grade	-	9	15	7	13	20
Counterparty has no external rating	185	175	87	302	315	223
No netting agreements in place:						
Counterparty is investment grade	4	7	1	-	1	-
Counterparty has no external rating	3	1	1	1	-	-
Amount recorded on unaudited Condensed Consolidated Statements of Financial Position	$ 502	$ 677	$ 397	$ 539	$ 611	$ 444

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 $14 million at September 30, 2013, which would not have a material impact on our consolidated results of operations, cash flows or financial condition.

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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 2012 Form 10-K.

Fuel Price Risk

Cargo Shipping Tropical Shipping’s objective is to reduce its exposure to higher fuel costs through fuel surcharges. However, these fuel surcharges do not remove our entire risk in periods of increasing fuel prices and volatility, or increased competition, and any relief may not be realized in the same period as the cost incurred. An increase of 10% in Tropical Shipping’s average cost per gallon for vessel fuel results in approximately $5 million in additional annual fuel expense. Fuel surcharges would be implemented to reduce the impact of the increased fuel expense.

ITEM 4. CONTROLS AND PROCEDURES.

(a) Evaluation of disclosure controls and procedures. Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of our disclosure controls and procedures, as such term is defined under Rule 13a-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the Exchange Act), as of September 30, 2013, the end of the period covered by this report. Based on this evaluation, our principal executive officer and our principal financial officer concluded that our disclosure controls and procedures were effective as of September 30, 2013, in providing a reasonable level of assurance that information we are required to disclose in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods in SEC rules and forms, including a reasonable level of assurance that information required to be disclosed by us in such reports is accumulated and communicated to our management, including our principal executive officer and our principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

(b) Changes in Internal Control over Financial Reporting. There were no changes in our internal control over financial reporting that occurred during the third quarter ended September 30, 2013, 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 9 to our unaudited Condensed Consolidated Financial Statements under the caption “Litigation.”

We recently commenced an investigation into payments to local officials and related persons at one of the foreign ports serviced by Tropical Shipping. While the investigation is ongoing, we believe that a number of payments were made over a series of years and the aggregate amount of these payments is less than $200,000 based upon information obtained to date. In October 2013, we voluntarily disclosed these matters to the U.S. Department of Justice (DOJ) and the SEC. We will cooperate with any investigation by the DOJ and the SEC. We presently are unable to predict the duration, scope or result of this investigation or of any governmental investigation.

Item 1A. Risk Factors.

For information regarding our risk factors, see the factors discussed in Part I, Item 1A. Risk Factors in our 2012 Form 10-K and Part II Item 1A. Risk Factors in our second quarter 2013 Form 10-Q. These risk factors could materially affect our business, financial condition or future results. The risks described in the referenced documents are not the only risks facing our 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 2013 and no unregistered sales of equity securities were made during this period.

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Item 6. Exhibits.

10	Second Amended and Restated Limited Liability Company Agreement of SouthStar Energy Services LLC, dated September 6, 2013 by and between Georgia Natural Gas Company and Piedmont Energy Company.
12	Statement of Computation of Ratio of Earnings to Fixed Charges.
31.1	Certification of John W. Somerhalder II pursuant to Rule 13a - 14(a).
31.2	Certification of Andrew W. Evans pursuant to Rule 13a - 14(a).
32.1	Certification of John W. Somerhalder II pursuant to 18 U.S.C. Section 1350.
32.2	Certification of Andrew W. Evans pursuant to 18 U.S.C. Section 1350.
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase.
101.DEF	XBRL Taxonomy Definition Linkbase.
101.LAB	XBRL Taxonomy Extension Labels Linkbase.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase.

SIGNATURE

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

AGL RESOURCES INC.
(Registrant)

Date: October 30, 2013

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